

\*\*\* E.O. 12866 Review – Draft – Do Not Cite, Quote, or Release During Review\*\*\*  
SAN 8670~~EO12866~~\_Good Neighbor Plan\_~~2060-AV51~~-Final\_-Preamble\_~~20230207~~ EO 12866  
~~Initiated20230131~~

6560-50-P

Style Definition: Heading 3

## 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

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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 **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].**

**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 <http://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 <http://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:

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#### 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
<del>AQM TSD</del>	<del>Air Quality Modeling Technical Support Document</del>
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

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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
EO	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



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IRA	Inflation Reduction Act
LAER	Lowest Achievable Emission Rate
LDC	Local Distribution Company
LME	Low Mass Emissions
LNB	Low-NO <sub>x</sub> 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 <sub>x</sub>	Nitrogen Oxides
NREL	National Renewable Energy Lab
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standard

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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 <sub>2.5</sub>	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

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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 <sub>2</sub>	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

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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).<sup>1</sup> 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.<sup>2</sup> As discussed in Section III of this notice, the EPA’s updated analysis of 2023 suggests that the states of Arizona, Iowa,

<sup>1</sup> See 80 FR 65291 (October 26, 2015).

<sup>2</sup> ~~As discussed in Section III of this notice, 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.~~



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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](#). ~~[INSERT CITE TO DISAPPROVAL FINAL]~~ 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.<sup>3</sup>

This final rule defines ozone season nitrogen oxides (NO<sub>x</sub>) emissions 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

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<sup>3</sup> In general, specific tribal names or reservations are not identified separately in this ~~proposal~~ final rule except as needed. *See* Section III.C.2 of this notice for further discussion about the application of this rule in Indian Country.

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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<sub>x</sub> Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.<sup>4</sup> 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<sub>x</sub> 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.  
~~This final rule implements the necessary emissions reductions as follows. The FIP requirements~~

<sup>4</sup> As explained in Section V.C.1 of this notice, 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.

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~~establish ozone season NO<sub>x</sub> emissions budgets for 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) and require EGUs in these states to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) NO<sub>x</sub> Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.<sup>5</sup> The EPA is amending existing FIPs for 12 states currently participating in the CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) to replace their existing emissions budgets established in the Revised CSAPR Update (with respect to the 2008 ozone NAAQS) with new emissions budgets. For seven states currently covered by the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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

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~~<sup>5</sup>As explained in Section V.C.1 of this notice, 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.~~

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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 notice, 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,

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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<sub>x</sub> 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 \(by better ensuring emissions reductions are maintained throughout each ozone season, year over year\). These features provide further assurance that pollution controls will be operated during the ozone season and that the emissions reductions that were determined to be necessary to eliminate significant contribution will be achieved. 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](#)

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document.

The EPA is making a finding that NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions limitations during the ozone season for the following unit types for sources in non-EGU industries:<sup>6</sup> 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

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<sup>6</sup> 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.

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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 notice 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.<sup>7,8</sup> Assessments of ozone control approaches have concluded that control strategies targeting reduction of NO<sub>x</sub> emissions are an effective method to reduce regional-scale ozone transport.<sup>9</sup>

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.<sup>10</sup> 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 ~~submittal~~ SIP revision. As with any other type of SIP

Commented [EO 128661]: Redundant word choice

Commented [EPA2R1]: Thank you - adjusted wording.

<sup>7</sup> Bergin, M.S. et. al. (2007) Regional air quality: local and interstate impacts of NO<sub>x</sub> and SO<sub>2</sub> emissions on ozone and fine particulate matter in the eastern United States. *Environmental Sci & Tech.* 41: 4677-4689.

<sup>8</sup> 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.

<sup>9</sup> *See* 82 FR 51238, 51248 (November 3, 2017) [citing 76 FR 48208, 48222 (August 8, 2011)] and 63 FR 57381 (October 27, 1998).

<sup>10</sup> 42 U.S.C. 7410(a)(2)(D)(i)(I).

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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 notice 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 notice for additional information). The EPA is deferring finalizing a finding at this time for Oregon (*see* Section IV.G of this notice for additional information).~~The EPA also had proposed not to change its prior approval of Oregon’s 2015 ozone transport SIP, and we are finalizing this determination (*see* Section IV.G of this notice 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<sub>x</sub> 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.

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~~In this rule, the EPA is issuing FIP requirements that include new ozone season NO<sub>x</sub> emissions budgets for 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 these emissions budgets begins in the 2023 ozone season.~~

The EPA is expanding the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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, 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<sub>x</sub> 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.<sup>11</sup> Finally,

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<sup>11</sup> 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

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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<sub>x</sub> 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.<sup>12</sup> Refer to Section VI.B of this notice 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<sub>x</sub> 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

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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.

<sup>12</sup> Three states, Kansas, Iowa, and Tennessee, will remain in the Group 2 Trading Program.

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Table II.A-1 for a list of North American Industry Classification System (NAICS) codes for each entity included for regulation under this proposed rule.

*B. Summary of the ~~Major~~ 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 notice.

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

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2023 and 2026.<sup>13</sup> 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.<sup>14</sup> Once quantified, the EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS (i.e., 0.70 ppb).<sup>15</sup> 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

<sup>13</sup> 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.

<sup>14</sup> 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.

<sup>15</sup> *See* Section [IV.F](#) of this notice for explanation of EPA's use of the 1 percent of the NAAQS threshold in the Step 2 analysis.

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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 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 notice for additional information).

~~Further evaluation of the locations in California to which Oregon contributes greater than 1 percent of the NAAQS leads the EPA to conclude downwind areas represented by these monitoring sites in California should not be considered interstate ozone transport receptors at Step 1. Therefore, the EPA is not changing its prior approval of the SIP submittal from the state of Oregon, because there is no significant contribution required to be eliminated under CAA section 110(a)(2)(D)(i)(I), as described in Section IV.G of this notice.~~

Based on the air quality analysis presented in Section IV of this notice, 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.

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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 notice to both EGU and industrial sources. The EPA assessed the potential emissions reductions in 2023 and 2026,<sup>16</sup> 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<sub>x</sub> emissions control technologies: (1) fully operating existing selective catalytic reduction (SCR) controls, including both optimizing NO<sub>x</sub> removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO<sub>x</sub> combustion controls; (3) fully operating existing selective non-catalytic reduction (SNCR) controls, including both optimizing NO<sub>x</sub> 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 notice and supported by the [“Technical Support Document \(TSD\) for the Final Federal Good Neighbor Plan for the 2015 Ozone National](#)

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<sup>16</sup> 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<sub>x</sub> budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NO<sub>x</sub> budgets for those states.

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Ambient Air Quality Standard, Docket ID No. EPA-HQ-OAR-2021-0668, EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD” (Mar. 2023), hereinafter referred to as the EGU NO<sub>x</sub> Mitigation Strategies Final Rule ~~TSD, Technical Support Document (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<sub>x</sub> 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<sub>x</sub> 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 notice for a full discussion of EPA’s analysis of NO<sub>x</sub> emissions mitigation strategies for EGU sources.

The EPA is requiring control stringency levels that offer the most incremental NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> SIP Call and the Clean Air Interstate Rule (CAIR), the EPA established EGU budgets premised on the widespread availability of retrofitting EGUs with post-



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combustion emissions controls such as SCR.<sup>17</sup> 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<sub>x</sub> 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 notice, 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,

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<sup>17</sup> *See, e.g.*, 70 FR 25162, 25205-06 (May 12, 2005).

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the EPA is requiring emissions performance levels for EGU NO<sub>x</sub> control strategies commensurate with those determined to be necessary in the NO<sub>x</sub> SIP Call and CAIR.

Based on the Step 3 analysis described in Section V of this notice, 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 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<sub>x</sub> per ozone season.

To identify appropriate control strategies for non-EGU sources to achieve NO<sub>x</sub> 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

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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.<sup>18,19</sup> 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 Technical Support Document TSD,](#) prepared for the proposed FIP.<sup>20</sup>

<sup>18</sup> The memorandum is available in the docket at <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150>.

<sup>19</sup> 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.

<sup>20</sup> The TSD is available in the docket at <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145>.

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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 notice. As discussed 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,”* for the final rule 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,<sup>21</sup> to estimate NO<sub>x</sub> 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 notice.

The EPA performed air quality analysis using the Ozone Air Quality Assessment Tool

<sup>21</sup> More information about the control measures database (CMDDB) can be found at the following link: <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution>.

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(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 notice.<sup>22</sup> 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 notice, 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.

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<sup>22</sup> 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.

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Based on the multi-factor test applied to both EGU and non-EGU sources and 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 Trading Program (the “Group 2

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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,<sup>23</sup> and affected EGUs within the borders of three states not currently covered by any CSAPR trading program for seasonal NO<sub>x</sub> 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<sub>x</sub> pollution controls will be operated throughout each ozone season, as described in Section VI.B of this notice. This rulemaking does not revise the budget stringency and geography of the existing CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 trading program.

The EPA is establishing preset ozone season NO<sub>x</sub> emissions budgets for each ozone season from 2023 through 2029, using generally the same Group 3 trading program budget-

<sup>23</sup> The EPA ~~would~~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.

setting methodology used in the Revised CSAPR Update, as explained in Section VI.B of this notice 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<sub>x</sub> 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 available to such facilities.<sup>24</sup> 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

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<sup>24</sup> 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).

dynamics during this period. The need and reasoning for the limited-period preset budget floor is further discussed in Section VI.B.4.

~~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<sub>x</sub> 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





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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
<b>Total</b>	<b>208,119</b>	<b>198,014</b>	<b>195,259</b>	<b>150,836</b>	<b>119,781</b>	<b>115,060</b>	<b>104,838</b>

\* Further information on the state-level emissions budget calculations pertaining to Table I.B-1 is provided in Section VI.B.4 of this notice 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 notice.

\*\* As described in Section VI of this notice, 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 notice 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 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<sub>x</sub> 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 ~~offer downwind stakeholders~~ 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

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operation of installed pollution controls. The EPA’s experience with the CSAPR trading programs has revealed instances where EGUs have reduced their SCR’s performance on a given day, or across the entire ozone seasons in some cases, including high ozone days.<sup>25</sup> 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.

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<sup>25</sup> See 86 FR 23090. The EPA highlighted the Miami Fort Unit 7 (possessing a SCR) more than tripled its ozone-season NOx emission rate between 2017 and 2019.

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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 ~~generally~~ 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<sub>x</sub> emissions limits listed in Table I.B-2 for reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; the NO<sub>x</sub> emissions limits listed in Table I.B-3 for kilns in Cement and Cement Product Manufacturing; the NO<sub>x</sub> emissions limits listed in Table I.B-4 for reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; the NO<sub>x</sub> emissions limits listed in Table I.B-5 for furnaces in Glass and Glass Product Manufacturing; the NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Emissions Limits for Pipeline Transportation of Natural Gas**



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Engine Type and Fuel	NO <sub>x</sub> Emissions Limit
Natural Gas Fired Four Stroke Rich Burn	1.0 g/hp-hr
Natural Gas Fired Four Stroke Lean Burn	1.5 g/hp-hr
Natural Gas Fired Two Stroke Lean Burn	3.0 g/hp-hr

**Table I.B-3: Summary of NO<sub>x</sub> Emissions Limits for Kiln Types in Cement and Concrete Product Manufacturing**

Kiln Type	NO <sub>x</sub> Emissions Limit (lb/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

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<sub>x</sub> Control Requirements for Iron and Steel and Ferroalloy Emissions Units**

Emissions Unit	NO <sub>x</sub> Emissions Standard or Requirement (lb/mmBtu)
Reheat furnace	Test and set limit based on installation of Low-NO <sub>x</sub> Burners

**Commented [EO 128667]:** Will EPA establish a test procedure for reheat furnaces?

**Commented [EPA8R7]:** §52.43 of the regulations outline the requirements that reheat furnaces without low-nox burners currently installed must comply with. The regulations specifically require sources to conduct a performance test, then propose a plan that includes installing low nox burners and setting source-specific emissions limits. For the performance testing specifically, the regulations rely on known test procedures under 40 CFR part 60, Appendix A-4.

**Table I.B-5: Summary of NO<sub>x</sub> Emissions Limits for Furnace Unit Types in Glass and Glass Product Manufacturing**

Furnace Type	NO <sub>x</sub> 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<sub>x</sub> 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 <sub>x</sub> /mmBtu)
Coal	0.20
Residual oil	0.20
Distillate oil	0.12
Natural gas	0.08

**Table I.B-7: Summary of NO<sub>x</sub> Emissions Limits for Combustors and Incinerators in Solid Waste Combustors or Incinerators**

Combustor or Incinerator, Averaging Period	NO <sub>x</sub> Emissions Limit
ppmvd on a 24-hour block averaging period	110 ppmvd
ppmvd on a 30-day rolling averaging period	105 ppmvd

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Section V.C of this notice provides an overview of the applicability criteria, compliance assurance requirements, and the EPA’s rationale in proposing 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 notice 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 notice 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 notice describes the Agency’s analyses of air quality data to inform this proposed 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 notice describes the EPA’s approach to quantifying upwind states’ obligations in the form of EGU NO<sub>x</sub> control stringencies and non-EGU emissions limits. Section VI of this notice 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<sub>x</sub> Group 3 trading program and compliance deadlines, as well as regulatory requirements and compliance deadlines for non-EGU sources. Section VII of this notice discusses the environmental justice ~~considerations analysis~~ of the rule, as well as outreach and engagement efforts. Section VIII of this notice describes the expected costs, benefits, and other impacts of this rule. Section IX of this notice provides a summary of proposed changes to the existing regulatory text applicable to the EGUs covered by

this rule; and Section X of this notice 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)<sup>a</sup>**

	3% Discount Rate	7% Discount Rate
Health Benefits <sup>b</sup>	\$200,000	\$130,000
Climate Benefits <sup>c</sup>	\$15,000	\$15,000 <del>N/A</del>
Compliance Costs <sup>d,e</sup>	\$14,000	\$9,400
<b>Present Value Net Benefits</b>	<b>\$200,000</b>	<b><del>\$140,000</del> <del>130,000</del></b>

**Commented [EO 128669]:** Though climate benefits are not discounted at a 7% rate. Consider including a footnote here to explain that point, connected to the comment below on the need for more table notes explaining that climate is not discounted at 7%.

**Commented [EPA10R9]:** Please see response below and edited table note.

**Commented [EO 1286611]:** ... climate benefits are only discounted at 3%, but this is a little confusing. It could be read to suggest that you are not adding climate benefits into the \$130B net benefits figure below: is that, in fact, what is happening, or is the total \$130B instead of \$136B because of rounding? It would be better to more fully explain how climate benefits are included in net benefits, the fact that climate benefits are discounted only at a 3% rate, and why it is appropriate to combine climate benefits discounted at 3% with other costs/benefits discounted at a 7% rate. In many other rules, EPA has table notes that address these point. Please copy from those examples.

**Commented [EPA12R11]:** Thank you. We checked the underlying estimates, and the line edits are accurate. In addition, the EPA has edited/expanded on the suggested footnote to clarify the values in the table.

**Commented [EO 1286613]:** Does this include climate benefits? Why doesn't EPA include those in this column, discounted at 3% consistent with guidance, to sum to NPV? Reviewer suggests it would be preferable to include the climate benefits value and add a footnote to explain that different discount rates are used for climate vs. other values

**Commented [EPA14R13]:** Please see response above.

**Commented [Round 215R13]:** 3/9/2023: Can EPA double-check whether the net benefits at 7% include the climate benefits? Want to ensure the 3% climate value above is carried through the table

**Commented [EPA16R13]:** We corrected the value – thank you.

**Commented [EO 1286617]:** Does this include climate benefits? Why doesn't EPA include those in this column, discounted at 3% consistent with guidance, to sum to NPV? Reviewer suggests it would be preferable to include the climate benefits value and add a footnote to explain that different discount rates are used for climate vs. other values

**Commented [EPA18R17]:** Please see response above.

**Commented [Round 219R17]:** 3/9/2023: Can EPA double-check whether the net benefits at 7% include the climate benefits? Want to ensure the 3% climate value above is carried through the table

**Commented [EPA20R17]:** We corrected the value – thank you.

	Health Benefits	\$13,000	\$12,000
Equivalent Annualized Value	Climate Benefits	\$970	<del>\$970</del> N/A
	Compliance Costs	\$910	\$770
	Net Benefits	\$13,000	\$12,000
		0	

<sup>a</sup> Rows may not appear to add correctly due to rounding.

<sup>b</sup> 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<sub>2.5</sub> 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.

<sup>c</sup> ~~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.~~

<sup>k</sup> ~~Climate benefits are calculated using four different estimates of the social cost of carbon (SC-CO<sub>2</sub>), methane (SC-CH<sub>4</sub>), and nitrous oxide (SC-N<sub>2</sub>O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). Together these represent the global SC-GHG. For presentational purposes in of this table, the climate benefits associated with the average SC-CO<sub>2</sub>GHG at a 3-percent discount rate are used in the columns displaying results of other costs and benefits that are discounted at either using a 3-percent or 7-percent discount rate, as well as a 7-percent discount rate, shown, but EPA does not have a single central SC-GHG point estimate.~~

<sup>d</sup> 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<sub>2.5</sub> 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

**Commented [EO 1286621]:** But that's a private discount rate. This table should show social costs and benefits, and so use 3%/7% rates.

**Commented [EPA22R21]:** See response below.

**Commented [Round 223]:** 3/9/2023: FN edits to clarify the point.

**Commented [EPA24R23]:** Thank you.

**Commented [EO 1286625]:** Providing sample note text for EPA's consideration

**Commented [EPA26R25]:** Thank you for the suggested text. Because we are only using SC-CO<sub>2</sub>, EPA suggests removing references to the other values to avoid confusion. Corresponding edits made to reflect this.

**Commented [EO 1286627]:** But that's a private discount rate. This table should show social costs and benefits, and so use 3%/7% rates.

**Commented [EPA28R27]:** Discussed by teleconference 3/10 and added sentence to Table Note d.

**Commented [Round 229R27]:** 3/9/2023: Ok, will review the RIA when it comes back.

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

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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<sub>x</sub> 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

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CSAPR trading program for seasonal NO<sub>x</sub> 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 ~~rates-rate~~ of 0.14 lb/mmBtu for coal-fired steam units greater than or equal to 100 MW in covered states. The backstop emissions ~~rates~~ 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



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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 notice 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 notice.

*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.<sup>26</sup> 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.<sup>27</sup>

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.<sup>28</sup> It includes a list of specific elements that “[e]ach such plan” must address.<sup>29</sup>

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.<sup>30</sup>

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<sup>26</sup> 42 U.S.C. 7410(a)(1).

<sup>27</sup> See *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 509-10 (2014).

<sup>28</sup> 42 U.S.C. 7410(a)(2).

<sup>29</sup> 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).

<sup>30</sup> 42 U.S.C. 7410(c)(1).

CAA section 110(a)(2)(D)(i)(I), also known as the “good neighbor” provision, provides the primary basis for this proposed rule.<sup>31</sup> 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].”<sup>32</sup> 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.”

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).<sup>33</sup> 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.<sup>34</sup> 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.<sup>35</sup> 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).<sup>36</sup>

Section 301(a)(1) of the CAA gives the Administrator the general authority to prescribe

<sup>31</sup> 42 U.S.C. 7410(a)(2)(D)(i)(I).

<sup>32</sup> *Id.*

<sup>33</sup> 42 U.S.C. 7407(d).

<sup>34</sup> 42 U.S.C. 7511, 7511a.

<sup>35</sup> 42 U.S.C. 7511a.

<sup>36</sup> 42 U.S.C. 7511(b).

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such regulations as are necessary to carry out functions under the Act.<sup>37</sup> 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 notice.

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).<sup>38</sup> 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 notice.

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

The EPA has issued several ~~major-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).

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<sup>37</sup> 42 U.S.C. 7601(a)(1).

<sup>38</sup> 42 U.S.C. 7601(d)(4).

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The “NO<sub>x</sub> SIP Call,” promulgated in 1998, addressed the good neighbor provision for the 1979 1-hour ozone NAAQS.<sup>39</sup> The rule required 22 states and the District of Columbia to amend their SIPs to reduce NO<sub>x</sub> emissions that contribute to ozone nonattainment in downwind states. The EPA set ozone season NO<sub>x</sub> budgets for each state, and the states were given the option to participate in a regional allowance trading program, known as the NO<sub>x</sub> Budget Trading Program.<sup>40</sup> The D.C. Circuit largely upheld the NO<sub>x</sub> 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<sub>2.5</sub>) NAAQS and 1997 ozone NAAQS.<sup>41</sup> CAIR required SIP revisions in 28 states and the District of Columbia to reduce emissions of sulfur dioxide (SO<sub>2</sub>) or NO<sub>x</sub>—important precursors of regionally transported PM<sub>2.5</sub> (SO<sub>2</sub> and annual NO<sub>x</sub>) and ozone (summer-time NO<sub>x</sub>). As in the NO<sub>x</sub> 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

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<sup>39</sup> *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<sub>x</sub> 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).

<sup>40</sup> “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 notice.

<sup>41</sup> *Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO<sub>x</sub> SIP Call*, 70 FR 25162 (May 12, 2005).

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respect to the 1997 PM<sub>2.5</sub> and 1997 ozone NAAQS.<sup>42</sup> On March 15, 2006, the EPA promulgated FIPs to implement the emissions reductions required by CAIR.<sup>43</sup> CAIR was remanded to EPA by the D.C. Circuit in *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. ~~2008~~), *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.<sup>44</sup>

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<sub>2.5</sub> NAAQS.<sup>45</sup> CSAPR required 28 states to reduce SO<sub>2</sub> emissions, annual NO<sub>x</sub> emissions, or ozone season NO<sub>x</sub> emissions that significantly contribute to other states' nonattainment or interfere with other states' abilities to maintain these air quality standards.<sup>46</sup> 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.

<sup>42</sup> 70 FR 21147 (April 25, 2005).

<sup>43</sup> 71 FR 25328 (April 28, 2006).

<sup>44</sup> *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, 76 FR 48208, 48217 (August 8, 2011).

<sup>45</sup> 76 FR 48208.

<sup>46</sup> 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).

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CSAPR was the subject of an adverse decision by the D.C. Circuit in August 2012.<sup>47</sup> 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 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.<sup>48</sup>

In 2016, the EPA promulgated the CSAPR Update to address interstate transport of ozone pollution with respect to the 2008 ozone NAAQS.<sup>49</sup> The final rule updated the CSAPR ozone season NO<sub>x</sub> emissions budgets for 22 states to achieve cost-effective and immediately feasible

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<sup>47</sup> 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*).

<sup>48</sup> *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, 81 FR 74504, 74511 (October 26, 2016).

<sup>49</sup> 81 FR 74504.

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NO<sub>x</sub> emissions reductions from EGUs within those states.<sup>50</sup> 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.<sup>51</sup> The CSAPR Update implemented the budgets through FIPs requiring sources to participate in a revised CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> were required with respect to the 2008 ozone NAAQS for 20 of the 22 eastern states covered by the CSAPR Update.<sup>52</sup>

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<sup>50</sup> One state, Kansas, was made newly subject to ozone season NO<sub>x</sub> requirements by the CSAPR Update. All other CSAPR Update states were already subject to ozone season NO<sub>x</sub> requirements under CSAPR.

<sup>51</sup> 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.

<sup>52</sup> *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.



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.<sup>53</sup>

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.<sup>54</sup> 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<sub>x</sub> 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

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<sup>53</sup> 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).

<sup>54</sup> *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, 86 FR 23054 (April 30, 2021).

strategies for EGUs and emissions sources in other industry sectors (non-EGUs), the EPA determined that the NO<sub>x</sub> 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.<sup>55</sup>

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.

**Commented [Round 230]:** 3/9/2023: Fn. 54 refers to the *Midwest Ozone Group* litigation over the Revised CSAPR Update and should be updated to reflect the recent favorable decision.

**Commented [EPA31R30]:** Added paragraph and deleted footnote.

### 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<sub>x</sub> and volatile organic compounds (VOCs) in the presence of sunlight.

<sup>55</sup> ~~The Revised CSAPR Update is currently subject to a petition for judicial review pending in the D.C. Circuit Court of Appeals, *Midwest Ozone Group v. EPA*, No. 21-1146 (D.C. Cir. June 25, 2021).~~

Emissions from electric utilities and industrial facilities, motor vehicles, gasoline vapors, and chemical solvents are some of the major sources of NO<sub>x</sub> 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<sub>x</sub> 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 level.<sup>56</sup> 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).<sup>57</sup> 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

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<sup>56</sup> 80 FR 65291.

<sup>57</sup> 40 CFR part 50, Appendix P to part 50

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.<sup>58</sup> (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*<sup>59</sup> and *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II*<sup>60</sup> 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

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<sup>58</sup> 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. O<sub>3</sub> by scenario and across models and years, within the overall signal of higher summer O<sub>3</sub> concentrations in a warmer climate.

<sup>59</sup> 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. <http://dx.doi.org/10.7930/J0R49NQX>

<sup>60</sup> 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.

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relative to a future without climate change.<sup>61,62,63</sup> 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 Chapter~~ 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.<sup>64</sup> 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<sub>x</sub> SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update that a regional NO<sub>x</sub> control strategy would be effective in reducing regional-scale transport of ozone precursor emissions. NO<sub>x</sub> emissions can be

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<sup>61</sup> 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

<sup>62</sup> 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.

<sup>63</sup> 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

<sup>64</sup> Bergin, M.S. et al. (2007) Regional air quality: Local and interstate impacts of NO<sub>x</sub> and SO<sub>2</sub> emissions on ozone and fine particulate matter in the eastern United States. *Environmental Sci & Tech*. 41: 4677–4689.

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transported downwind as NO<sub>x</sub> 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<sup>65</sup> continue to show the importance of NO<sub>x</sub> emissions for ozone transport. This analysis is included in the docket for this rulemaking.

Further, studies have found that EGU NO<sub>x</sub> 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<sub>x</sub> reductions achieved under the NO<sub>x</sub> Budget Trading Program (i.e., the NO<sub>x</sub> SIP Call) shows that regulating NO<sub>x</sub> emissions in that program was highly effective in reducing ozone concentrations during the ozone season.<sup>66</sup>

Previous regional ozone transport efforts, including the NO<sub>x</sub> SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update, required ozone season NO<sub>x</sub> reductions from EGU sources to address interstate transport of ozone. Together with NO<sub>x</sub>, the EPA has also identified VOCs as a precursor in forming ground-level ozone. Ozone formation chemistry can

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<sup>65</sup> 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>.

<sup>66</sup> Butler, et al., "Response of Ozone and Nitrate to Stationary Source Reductions in the Eastern USA." *Atmospheric Environment*, 2011.

be “NO<sub>x</sub>-limited,” where ozone production is primarily determined by the amount of NO<sub>x</sub> emissions or “VOC-limited,” where ozone production is primarily determined by the amount of VOC emissions.<sup>67</sup> The EPA and others have long regarded NO<sub>x</sub> to be the more significant ozone precursor in the context of interstate ozone transport.<sup>68</sup>

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 notice, 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<sub>x</sub> 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<sub>x</sub>-limited, rather than VOC-limited. Therefore, the rule’s strategy for reducing regional-scale transport of ozone targets NO<sub>x</sub> 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<sub>x</sub> mitigation strategies from other sources are discussed in Section V.B of this notice.

In Section V of this notice, the EPA describes the multi-factor test that is used to determine NO<sub>x</sub> 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

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<sup>67</sup> “Ozone Air Pollution.” *Introduction to Atmospheric Chemistry*, by Daniel J. Jacob, Princeton University Press, Princeton, New Jersey, 1999, pp. 231–244.

<sup>68</sup> 81 FR 74514.

receptors. Based on the implementation schedule established in Section VI.A of this notice, 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<sup>69</sup> 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

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<sup>69</sup> Available at <https://www.epa.gov/sites/default/files/2016-02/documents/20151001ria.pdf>.



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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 ~~impacts-analysis~~ of this rule is located in Section VII of this notice 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<sub>x</sub> 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 ~~Chapter-Section~~ 11 of the ~~RTC~~ document.

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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<sub>x</sub> 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.<sup>70</sup> 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

<sup>70</sup> See CSAPR, Final Rule, 76 FR 48208, 48248-48249 (August 8, 2011); CSAPR Update, Final Rule, 81 FR 74504, 74517-74521 (October 26, 2016).

**Commented [Round 232]:** 3/9/2023: Suggested text:

In analyzing significant contribution at Step 3, where there is linkage between an upwind source and a downwind receptor, we identify what level of emission control is available, considering cost, to reduce emissions. We develop an allowance budget based on application of that technology to the sources, and ensure it does not lead to under or overcontrol at the downwind linked receptors. The level of emission control at each source identified in Step 3 is what EPA deems to eliminate significant contribution.

The trading program enhancements identified here are designed to ensure that sources actually achieve that level of emission control and thereby eliminate significant contribution. The enhancements ensure that the allowance budget reflects the potential to secure the level of emission control identified at Step 3 at the sources active in the trading program. Alternatively, EPA could simply implement source-specific emission rates reflecting that level of control—but doing so would require loss of the flexibilities inherent in a trading program, as well as the incentive it provides for innovations that can reduce emissions beyond the technologies identified by EPA.

**Commented [EPA33R32]:** Thank you for the suggested language. We incorporated it into Section VI.B.

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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 ~~generally~~ 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.<sup>71</sup> 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.

<sup>71</sup> 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. in chapters 1 and 2 of the Response to Comment document located in the docket for this action.

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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.](#)

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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 ~~clearly~~ 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.”<sup>72</sup> 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<sub>x</sub> SIP Call and CAIR<sup>73</sup>), the CAA does not require such an approach.

<sup>72</sup> 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.

<sup>73</sup> For information on the NO<sub>x</sub> SIP call see 63 FR 57356 (October 27, 1998). For information on CAIR see 70 FR 25162 (May 12, 2005).

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2018 Memoranda. As commenters point out, the EPA issued three “memoranda” in 2018 to provide some assistance to states in developing these SIP submittals.<sup>74</sup> 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

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<sup>74</sup> 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>.

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<sup>75</sup> 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."<sup>76</sup> 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."<sup>77</sup> Attachment A to the March 2018 memorandum, therefore, does not 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

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<sup>75</sup> "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.

<sup>76</sup> March 2018 memorandum, Attachment A at A-1.

<sup>77</sup> *Id.*

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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.<sup>78</sup>

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<sub>x</sub> 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

<sup>78</sup> 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).

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projections in Section IV of this notice 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 notice, 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 notice, 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. ~~Commenters have not established that this approach is either unlawful or arbitrary and capricious.~~ 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

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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 notice. 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<sub>x</sub> 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

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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 notice. 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 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](#), ~~(AQM 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

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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 notice, 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 notice 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

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inventory information and other updates. It is ~~entirely~~ reasonable for the Agency to improve its understanding of a situation before taking final ~~action~~ rule, and ~~it is surely expected that~~ the Agency ~~would promulgate a FIP using~~ the best information available ~~at the time it takes such action 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.<sup>79</sup> 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 ~~at all~~ 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 ~~four~~three upwind states included in the ~~proposed~~FIP went from being unlinked to being linked in 2023 between the 2011-based modeling provided in the March 2018 memorandum and the 2016v~~32~~-based modeling – Alabama, Minnesota, ~~and Nevada, and Tennessee.~~

<sup>79</sup> 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).

**Commented [EO 1286636]:** Were these upwind or downwind states, or a mix of both? It could be read as if these are all upwind, in which case 4 new linkages is fairly significant

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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.<sup>80</sup> 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. ~~And 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.<sup>81</sup>

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,<sup>82</sup> we gave states and other interested parties multiple opportunities

<sup>80</sup> See <https://www.epa.gov/air-emissions-modeling/2016v2-platform>.

<sup>81</sup> See <https://www.epa.gov/scram/photochemical-modeling-applications>.

<sup>82</sup> <https://www.epa.gov/air-emissions-modeling/2016v2-platform>.

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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 ~~entirely~~ 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 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

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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

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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<sub>x</sub> 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 contention~~ 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 ~~impose-implement~~ the necessary emissions controls. The EPA is not empowered to ~~rely-require on~~ 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) ~~clearly~~ 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 notice. With the implementation of the selected controls

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(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). Contrary to commenters’ contentions, 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). The statute does not define the term “amount” in the way commenters suggest (or in any other way). The statute does not define the term in this way (or any 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.*, See 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.”).<sup>83</sup>

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).<sup>84</sup> 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

<sup>83</sup> 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 ~~elsewhere in this rule~~ [Section VI.B](#).

<sup>84</sup> 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).

provided that are expressed in micrograms per cubic meter.<sup>85</sup> 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.

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<sup>85</sup> 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 P.L. 95-95, 91 Stat. 685, 693, 732, 746.

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’ ~~misconception~~, 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 (~~considering economic growth factors and the like~~) 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 at 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<sub>2</sub> 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).<sup>86</sup>

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<sub>x</sub> SIP Call, 63 FR at 57378-79 (discussing approvability of rate-based emissions limit approaches for implementing NO<sub>x</sub> 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<sub>x</sub> emissions to the budget amounts. Thus, the overall budget amount is not an independently enforceable requirement.”); CAIR, ~~71-70 FR~~ at 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,

<sup>86</sup> 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 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 ~~captured-authorized~~ by the term “quantity,” a term also used in CAA section 302(k).)

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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 notice. 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~~ ~~rejects~~ 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 notice. The relationship of ~~theour~~ control strategy to the assessment of overcontrol is discussed in Section V.D.4 of this notice. ~~And the~~ ~~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, Section II.C. of this notice.~~

*a. Step 1 Approach*

As proposed, the EPA ~~generally~~ 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 ~~apply~~ 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 notice, 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.

~~While the EPA has confidence in the reliability of the modeling for projecting air quality conditions and contributions in future years~~ 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. 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,

**Commented [EO 1286642]:** Why not?

**Commented [EPA43R42]:** There is no expectation that any air quality modeling will exactly match the corresponding measured data. As described in the Air Quality Modeling TSD, model performance statistics for EPA final rule modeling are within model performance benchmarks offered in recent peer-reviewed publications.



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 ~~be reached~~ technically in attainment in 2023, we have ~~reliable~~ 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 notice.

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.<sup>87</sup> The EPA evaluated each state’s contribution based on the average relative downwind impact calculated over multiple days.<sup>88</sup> 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

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<sup>87</sup> For ozone, the impacts include those from VOC and NO<sub>x</sub> from all sectors.

<sup>88</sup> 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](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](https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf)).

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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 notice.

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 notice and in the ~~RTC document~~*Response to Comments (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.<sup>89</sup> For states that are linked at Step 2 to downwind air quality problems, CSAPR, the CSAPR Update, and the Revised CSAPR Update evaluated NO<sub>x</sub> reduction potential, cost, and downwind air quality improvements available at various mitigation technology breakpoints (represented by cost thresholds) in the multi-factor test. In

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<sup>89</sup> 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).

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<sub>x</sub> 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*.<sup>90</sup>

In this action, the EPA applies this approach to identify EGU and non-EGU NO<sub>x</sub> 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<sub>x</sub> controls in light of the downwind air quality problems. The EPA’s evaluation of available NO<sub>x</sub> 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 ~~generally~~ commensurate with the control strategy for EGUs.

**Commented [EO 1286644]:** Flag for further discussion: “maximizing cost-effectiveness” is a slightly unusual phrase and does not seem to track with “reasonable balance.”

**Commented [EPA45R44]:** This is an accurate description of prior rules. Note also that “maximizing cost-effectiveness” refers to selecting a stringency at the knee in the curve, which is different than maximum control level or maximum benefits to costs.

<sup>90</sup> *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489 (2014).

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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<sub>x</sub> 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 notice.

In this rule, the EPA also continues to apply its approach for assessing and avoiding “over-control.” In *EME Homer 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~~~~excluded~~).

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 at 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 notice, does not find any over-control at the final control stringency selected.

This evaluation of cost, NO<sub>x</sub> 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 with these comments. The Agency has consistently and successfully regulated EGUs' ozone season NO<sub>x</sub> emissions under the good neighbor provision for over 25 years, beginning with the 1997 NO<sub>x</sub> 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) and the Department of Energy (DOE) have primary responsibility for ensuring reliability of the bulk electric system, the EPA has ensured that its final rule here will not create electric

**Commented [EO 1286646]:** DOE's responsibility regarding the reliability of the bulk electric system is important but limited and we would not generally characterize DOE as having "primary" responsibility for ensuring reliability.

If this is a reference to DOE's authority under section 202(c) of the Federal Power Act, recommend including both a discussion of FERC's general authority/responsibility to ensure bulk power system reliability and a separate statement about that specific authority, which is generally short-term and limited to specific grid emergency circumstances (as well as other related roles DOE plays such as the Sector Risk Management Agency for the energy sector). Reviewing agency supports including discussion of these authorities and would be happy to work with EPA to craft appropriate language.

**Commented [EPA47R46]:** We have accepted the suggested text edits. This was not intended as a reference to FPA section 202(c) authority. Given that the EGU portions of this rule are being implemented as a flexible trading program, we see the type of relief provided under section 202(c) as unnecessary.

**Commented [EO 1286648]:** Recommend clarifying that this refers to the bulk electric system, which is both the area of authority for FERC and the relevant component of electric system reliability at issue with these power plant rules.

**Commented [EPA49R48]:** Edit accepted.

reliability concerns. See Section VI.B.1.d of this notice. 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 authorities, including Reliability Coordinators who commented on the proposed rule, including several Regional Transmission Organizations (RTOs) as well as non-RTO entities, Independent System Operators (ISOs), non-RTO or ISO balancing authorities, and others,~~ throughout the rulemaking process.<sup>91</sup>

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<sub>x</sub> SIP Call and the establishment of the NO<sub>x</sub> 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 ~~major~~ interstate ozone transport rulemakings has focused on the regulation of ozone-precursor emissions from the power sector (all but the NO<sub>x</sub> 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<sub>x</sub> SIP Call); 70 FR 25165 and 71 FR 25343 (CAIR and CAIR FIP);

<sup>91</sup> 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.

**Commented [EO 1286650]:** It's not clear why stakeholder meetings would solve a record problem regarding whether there would be a reliability harm not accounted for in the rule. Is there other record evidence EPA could point to here?

**Commented [EPA51R50]:** EPA's response to comments on reliability is discussed later in the document, in Section VI.B.1.d.

**Commented [EO 1286652]:** Is this intended to reference NERC-designated and FERC-approved "[Reliability Coordinators \(nerc.com\)](#)"? There is substantial overlap between the RTOs and Reliability Coordinators, but they are not exactly the same.

Others that would be worth listing if EPA has engaged directly are the FERC-designated Reliability Organization (NERC) and the Regional Reliability Organizations.

If the intent is to discuss entities with responsibility over resource adequacy (i.e., is there enough capacity to meet peak demand), that would be a different set of actors that would include RTOs/ISOs as well as state PUCs. But would recommend specifically including language about resource adequacy rather than merely referring to "reliability" generally. EPA has some good language about this in the Resource Adequacy and Reliability TSD that was part of the final Clean Power Plan rule. [TSD: Resource Adequacy and Reliability Analysis \(epa.gov\)](#)

**Commented [EPA53R52]:** We have rephrased the sentence and removed the term "reliability authorities". We did not receive comments on the rule from NERC or any of the Regional Entities. We have also added a reference to the Resource Adequacy and Reliability Analysis TSD prepared for this rule, not in this section but in Section VI.B.1.d.



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76 FR 48210-11 (CSAPR); 81 FR 74507 (CSAPR Update); 86 FR 23061 (Revised CSAPR Update).<sup>92</sup>

This rule, like all prior EPA ozone-transport ~~rulemakings, which imposed requirements on the power sector,~~ regulates only one aspect of the operation of fossil-fuel fired EGUs, that is, the emissions of NO<sub>x</sub> as an ozone-precursor pollutant during the ozone season. This rule limits EGU NO<sub>x</sub> 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

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<sup>92</sup> 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.

specific compliance strategy.<sup>93</sup> 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 ~~entirely~~ 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

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<sup>93</sup> 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 ~~untoward~~ impact on system reliability ~~is caused~~. 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 notice.

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<sub>x</sub> 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<sub>x</sub> 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

**Commented [EO 1286654]:** EPA might consider also referencing a case in which the court was considering the extent of other regulators' authority vis-a-vis FERC's authority under the FPA rather than the other way around. For example, the discussion in *Hughes v. Talen*, 578 U.S. 150, 166 (2016) or the discussion in *Oneok v. Learjet*, 573 U.S. 373, 385 (2015). EPA might also consider citing to FERC precedent that there is no statutory conflict between flexible environmental regulations and FERC's authority to ensure grid reliability. There is a good discussion of FERC precedent in Sections I.D and I.E of the following brief from former FERC commissioners: [20-1530 Amicus Brief of Former Commissioners of the Federal Energy Regulatory Commission.pdf \(supremecourt.gov\)](#).

**Commented [EPA55R54]:** Added “see also” cite to Hughes.

technology, that is a choice that the EGU owner/operator can freely make under this rule.<sup>94</sup>

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.”).

<sup>94</sup> As explained in Section V.B of this notice, 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 have the effect of forcing the retrofit of an SCR, but such a mandated control installation through the establishment of a technology-based emissions limit is entirely 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.

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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 notice. Further comments regarding legal authority for “generation shifting,” relationship to state authorities, and expertise associated with grid reliability are addressed in ~~Chapter~~ Section ~~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 notice.

*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 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

**Commented [EO 1286656]:** Interagency reviewer requests that EPA provide the RTC

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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<sub>x</sub> SIP Call, *see* 63 FR at 57365.<sup>95</sup> See also Michigan v. EPA, 213 F.3d 663, 690-93 (upholding the inclusion of certain non-EGU boilers in the NO<sub>x</sub> 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 at 48247-48 (“[D]eveloping the additional information needed to consider NO<sub>x</sub> 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

<sup>95</sup> Specifically, in the NO<sub>x</sub> 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<sub>x</sub> SIP Call model rule.

**Commented [EO 1286658]:** Suggest also adding that in response to a challenge to EPA’s regulation of industrial boilers in the NO<sub>x</sub> SIP Call, the D.C. Circuit was clear that EPA had appropriately regulated industrial boilers as significant contributors to nonattainment, and that EPA had not acted arbitrarily in doing so. *Michigan*, 213 F.3d at 690–93. In this case, evidence in the record ran contrary to industry plaintiff’s claim that “industry boilers as a group have no impact on long-range industry transport,” and “EPA reiterated this finding[.]”, it relied on the finding, and industry plaintiffs never challenged it during the comment period. Therefore, [the court] *cannot say EPA’s inclusion of non-EGUs in the group of significantly contributing sources was arbitrary.*” *Id.* (emphasis added)

**Commented [EPA59R58]:** Added sentence.

**Commented [EO 1286660]:** Suggest also adding CAIR as an example, which also allowed states to include non-EGUs in their trading programs. *See* 40 C.F.R. § 51.123(aa)(2)(1) (“The state may . . . include all non-EGUs subject to the State’s emissions trading program”); *see also* EPA, QUESTIONS AND ANSWERS CONCERNING NON-EGUS TRANSITIONING FROM THE NO<sub>x</sub> BUDGET TRADING PROGRAM TO THE CAIR NO<sub>x</sub> PROGRAM, <https://archive.epa.gov/airmarkets/programs/cair/web/pdf/qasformnon-egus.pdf> (instructing states on the effects of bringing or not bringing non-EGUs into their Clean Air Interstate Rule trading program).

**Commented [EPA61R60]:** We don’t think adding a cite to CAIR is useful to support our authority to regulate non-EGUs for transport. In the CAIR obligations rule, while we allowed states the option of meeting their emission reduction obligations by imposing limits on non-EGUs instead of, or in addition to EGUs, we based our quantification of the obligations solely on EGUs. We assumed we did have authority, but we focused on EGUs.

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 at 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,

**Commented [EO 1286662]:** Suggest supplementing this point by adding that in CSAPR, EPA recognized that “potentially substantial” non-EGU reductions would be available in future rulemakings with higher cost thresholds. 76 FR at 48,256 (“EPA believes that potentially substantial non-EGU ozone season NOX reductions become available approaching the \$1,000/ton cost threshold.”)

**Commented [EPA63R62]:** Added language.

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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 at 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



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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 is generally~~ 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 the notice. See Section V.C of the notice.~~

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 notice. These emissions control strategies are generally comparable to the emissions reduction requirements that similar sources in downwind states are already required to meet. *See* Section V.B.2 of this notice. 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 ~~approximately 41~~ industries, as identified by North American Industry Classification System codes, we analyzed, only ~~nine seven~~ industries met the criteria for further evaluation of

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significant contribution. *See* Section V.B.2 of this notice. Further, the EPA finds that these strategies do not result in “overcontrol.” *See* Section V.D.4 of this notice. 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.<sup>96</sup>

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 ~~contention-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, ~~generally~~ 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<sub>x</sub>, 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

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<sup>96</sup> Certain changes in the emissions control strategies for non-EGUs reflecting comments and updated information are explained in Section VI.C of this notice ~~and in the RTC document~~.

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).

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 **on its face** 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

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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 notice. 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 notice.

*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

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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 notice. Here, we evaluate commenters’ more general ~~arguments~~ 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

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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 notice 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 notice 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.

~~It is certainly true that N~~ot 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. ~~These commenters may be overstating the relative importance of “cost” in the EPA’s Step 3 analysis.~~The EPA’s design of cost thresholds derives from the identification of discrete types

of NO<sub>x</sub> 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. ~~Said differently, when the EPA determines not to require controls at a higher cost threshold, it is not on grounds that they are simply “too expensive for industry.”~~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.

~~Further, t~~There are always inherent uncertainties in identifying a ~~precise-representative~~ cost per ton value for any particular control stringency, but this in itself does not upset the EPA’s ability

**Commented [EO 1286666]:** EPA should do more to explain why the levels it has chosen are the “cost-effective” ones appropriate under the statute vs. the regulatory alternatives that EPA has analyzed (e.g., more stringent levels)

**Commented [EPA67R66]:** Edits incorporated in following sentences.

**Commented [Round 368]:** 3/13: Clarifying that the knee of the curve reflects the point beyond which relative costs increase and *relative* additional emissions reductions decrease. Without “additional” this sentence suggests that more stringent techs reduce fewer emissions than less stringent techs, which by definition cannot be true.

**Commented [EPA69R68]:** Edit accepted.

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to render an overall policy judgment based on the Step 3 factors as to ~~the level of emissions reductions required a set of emissions control strategies that together eliminate significant contribution.~~ ~~The EPA provided this same explanation regarding our Step 3 analysis in responding to similar comments on the Revised CSAPR Update as related to diversity in the costs EGU sources might bear under that program.~~ 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,<sup>97</sup> 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 ~~generally~~ 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

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<sup>97</sup> For reheat furnaces in the Iron and Steel Mills and Ferroalloy Manufacturing industry, the EPA is establishing requirements to operate low-NO<sub>x</sub> 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 notice.



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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<sub>x</sub> 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-source~~ ~~at the 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 achieve a level of emissions performance~~ ~~to identify and eliminate significant contribution under CAA section 110(a)(2)(D)(i)(I)~~ based on cost-effective and proven control technologies that ~~is~~ ~~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 at 48210. Here it is not surprising that a more stringent level of control ~~as expressed in dollars per ton~~ 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 notice. Those air quality benefits continue to compare favorably to the air quality benefits that will be delivered

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through the combined non-EGU emissions limits, which apply to nine non-EGU industries (see Section V.C of this notice). We find that the implementation of both the EGU and non-EGU strategies identified in Section V of this notice 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 ~~any overcontrol based on the present record~~ 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 ~~hereby 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 the notice.

*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

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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<sub>x</sub>-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 notice 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<sub>x</sub> 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<sub>x</sub> 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

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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 notice). 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 proposed EGU emissions reductions using a CSAPR NO<sub>x</sub> trading program is further described in Section VI.B of this notice.

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<sub>x</sub> emissions reductions through emissions rate limits and control technology requirements for certain non-EGU industrial sources that the

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EPA found at Step 3 to be relatively impactful<sup>98</sup> on downwind air quality is an effective strategy for reducing regional ozone transport. Therefore, the EPA is establishing NO<sub>x</sub> 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 ~~proposal~~final rule. This is consistent with the EPA's transport actions dating back to the NO<sub>x</sub> SIP Call and the NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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~~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,

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<sup>98</sup> 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.

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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 ~~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 ~~At~~ 1057-58. The EPA is ~~adopting~~ 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

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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 notice 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 notice. 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 notice.

Responses to comments on the EGU trading program enhancements and adjustments in the final rule are contained in Section VI.B of this notice. 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 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<sub>x</sub>, for reasons explained in Section VI.B.1 of this notice. 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

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which is discussed in Section VI.B.1.c.ii of this notice, 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 Part 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

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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~~ incentive the control strategy determined at Step 3. This ~~adjustment was~~ was an innovation the EPA introduced in the Revised CSAPR

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Update. See 82 FR 23121-22.<sup>99</sup> 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 notice. The EPA also explained this in the proposal. See 87 FR at 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 notice.

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

<sup>99</sup> 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.

Commented [EPA70]: Addition in response to interagency comment.

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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 notice, 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 ~~entirely~~ 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 notice.

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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<sub>x</sub> 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. For instance, under the CSAPR Update, the preset budget approach enabled large, frequently run units with existing SCR controls to not operate those controls (e.g., Miami Fort) even though the EPA’s assessment (as reflected in the Revised CSAPR Update) is that the

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~~operation of those controls remained necessary for eliminating significant contribution to nonattainment and interference with maintenance of that NAAQS. 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 0.99 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”.~~<sup>100</sup>

~~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 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~~

<sup>100</sup> 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>.



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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 its preset~~ emissions budgets for initial control periods, over time those ~~preset 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 at 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). Moreover, 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 policy justification at Step 3 that can be sustained within that framework for an upwind source to relax or cease operating its emissions controls simply because other sources of pollution have been reduced 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, ~~contrary to commenter’s supposition,~~ these trading program enhancements are ~~entirely~~ 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. ~~It is hardly surprising that These enhancements to ensure complete the~~ elimination of significant contribution ~~across all upwind states and throughout each ozone season and avoid the risk of under control.~~ 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 notice. This does not detract from the statutorily-authorized basis for these changes, and they ~~happen to also have environmental justice benefits. The EPA’s analysis in the proposal, 87 FR 20107, and in this final record, see Section VII of this notice, is that the~~ innovations in the program will be particularly helpful in delivering and guaranteeing air quality

**Commented [Round 371]:** 3/13: Why these caveats? Shouldn't significant contribution be eliminated in all areas in a region and not just when good emissions performance is most essential?

**Commented [EPA72R71]:** We would like to retain these caveats.

**Commented [Round 273]:** 3/9/2023

**Commented [EPA74R73]:** Edit accepted

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~~benefits in perpetuity to downwind communities that suffer a disproportionate burden from ozone pollution.~~ 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-see id.* at 515. And, we are of course fully aware that we have changed our position; *See-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

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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 126~~, 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).<sup>101</sup> 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 notice.

The EPA is finalizing this FIP action now to address 23 states' good neighbor obligations for the 2015 ozone NAAQS.<sup>102</sup> 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.

<sup>101</sup> *National Ambient Air Quality Standards for Ozone*, Final Rule, 80 FR 65292 (~~Oct.~~ October 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.

<sup>102</sup> 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).

**Commented [EO 1286675]:** Oct. 26 is the date in the footnote and in the Federal Register.

**Commented [EPA76R75]:** Oct 26 is correct. Thank you!

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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, 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 ~~entirely~~ 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.<sup>103</sup> CAA section 110(c) authorizes the EPA to

<sup>103</sup> 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*

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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.”<sup>104</sup> 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,

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*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.

<sup>104</sup> See *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 509 (2014) (citations omitted).

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West Virginia, Wisconsin).<sup>105</sup> 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.<sup>106</sup> The EPA proposed to disapprove good neighbor SIP submissions for four additional states, California, Nevada, Utah, and Wyoming, on May 24, 2022.<sup>107</sup>

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.<sup>108</sup> This action established the EPA’s authority to promulgate FIPs for the disapproved states. (As explained in Section IV.F of this notice, 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 notice, 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

<sup>105</sup> 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).

<sup>106</sup> See 87 FR 64412.

<sup>107</sup> See 87 FR 31443 (California); 87 FR 31485 (Nevada); 87 FR 31470 (Utah); 87 FR 31495 (Wyoming).

<sup>108</sup> See 88 FR 9336.

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(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.<sup>109</sup> 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,<sup>110</sup> 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.<sup>111</sup>

Further information on the procedural history establishing the EPA’s authority for this final rule is provided in a document in the docket.<sup>112</sup>

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

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<sup>109</sup> *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).

<sup>110</sup> *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).

<sup>111</sup> *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).

<sup>112</sup> 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 at proposal (Document no. EPA-HQ-OAR-2021-0668-0131).



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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).<sup>113</sup> 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,<sup>114</sup> which fell on August 3, 2021.<sup>115</sup> As discussed in Section VI.A of this notice, 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.<sup>116</sup> 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

<sup>113</sup> *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)).

<sup>114</sup> *Maryland v. EPA*, 958 F.3d 1185, 1203-04 (D.C. Cir. 2020).

<sup>115</sup> 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).

<sup>116</sup> 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)).

#### 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,<sup>117</sup> 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 notice 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 of the notice. 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

<sup>117</sup> See the Air Quality Modeling ~~Technical Support Document (AQM-TSD)~~ Proposed Rule TSD in the docket for this proposed rule.

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.<sup>118</sup> As described later, the EPA is proposing to include 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 of the notice) and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction – the EPA here proposes 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

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<sup>118</sup> 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.

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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.<sup>119</sup>

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.<sup>120</sup> For EGU applicability criteria, *see* Section VI.B of this notice; for industrial-source applicability criteria, *see* Section VI.C of this notice. To EPA’s knowledge, only one existing EGU or industrial source is located within

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<sup>119</sup> *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.”).

<sup>120</sup> 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.

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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 at 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<sub>x</sub>, 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.<sup>121</sup> 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 proposes to apply—consistent with the methodology of allocating upwind responsibility in prior transport rules going back to the NO<sub>x</sub> 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 notice 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

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<sup>121</sup> See Section VI.B.9 of this notice 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.

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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<sub>x</sub> 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

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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 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 ~~generally~~ 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 notice, 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<sub>x</sub> 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.



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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<sup>122</sup> 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 notice, 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,<sup>123</sup>

<sup>122</sup> <https://www.epa.gov/system/files/documents/2022-03/fy-2022-2026-epa-strategic-plan.pdf>.

<sup>123</sup> Executive Order 13985 (January 20, 2021): <https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executiveorder-advancing-racial-equity-and-support-for-underserved-communities-through-the-federal-government/>.

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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,

Pub. 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).<sup>124</sup>

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.<sup>125</sup> 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 (collectively “excluded Indian country lands”).

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<sup>124</sup> 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.

<sup>125</sup> Available in the docket for this rulemaking.

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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.<sup>126</sup> 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** notice 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.<sup>127</sup> 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

<sup>126</sup> 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.

<sup>127</sup> 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).

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previously.<sup>128</sup> 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,<sup>129</sup> 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

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<sup>128</sup> 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.

<sup>129</sup> 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.).

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notice, 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~~~~Should~~ a court find any discrete aspect of this notice to be invalid ~~on petition(s) for judicial review~~, the Agency believes that ~~in general~~, the remaining aspects of this rule can and should continue to be implemented to the extent possible. ~~This is important to preserve 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).~~

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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 ~~view~~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. ~~The Agency has full confidence in the lawfulness of this final rule; but In~~ the event any part of it is found invalid, our intention is that the remaining portions should continue to be implemented ~~to the extent possible, taking into account the nature and scope of~~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).

**Commented [Round 277]:** 3/9/2023: Please consider whether to add that the trading provisions are severable: even if the trading provisions were struck down, the remaining requirements for the EGUs would apply.

**Commented [EPA78R77]:** We think the severability position is adequately expressed.

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#### **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 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 notice 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 this proposal, the EPA recognizes that the 2021 Marginal area attainment date has already passed. Further, based on the timing of this proposal, it will not be possible to finalize this rulemaking before the 2022 ozone season has 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 ~~the~~ 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. These years also coincide with the last full ozone seasons before future attainment dates for the 2015 ozone NAAQS, and 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](#)~~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:* ~~Although commenter criticizes the EPA’s selection of 2023 as an appropriate analytic year, they do not identify their preferred alternative, nor are their arguments against use of 2023 to identify linked upwind states compelling.~~ The EPA maintains ~~its position~~ that 2023 is an appropriate analytic year and comports with the relevant caselaw. Section VI.A further

**Commented [EO 1286679]:** EPA’s response is a bit confusing, could be clarified by a better summary of the comment received. Was the commenter requesting that EPA align the good neighbor requirements for upwind states with the attainment dates? If possible, it would be helpful to provide a general characterization of what the commenter wanted EPA to do.

**Commented [EPA80R79]:** Added sentence to comment summary.

~~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 never held that, and such a requirement is both untethered from the statute and almost certainly unworkable in practice. It would necessitate coordinating the activities of multiple states and the EPA regional and headquarters offices to a level of fine tuning that effectively could preclude the implementation of good neighbor obligations altogether. Indeed, commenter offers no explanation how the EPA or upwind states should coordinate upwind emissions control obligations for states 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).~~

~~However, t~~Contrary to commenter’s interpretation, ~~what t~~the D.C. Circuit has held ~~is~~ 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’

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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.](#)

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The relevance of CAA sections 172, 177, and 179 to the selection of the analytic year in this action is not clear. ~~MOG-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).<sup>130</sup> 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

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<sup>130</sup> September 24, 2018, for the San Antonio area. 83 FR 35136 (July 25, 2018).

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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). ~~*See also*~~; *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-

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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 and 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 linked to multiple downwind receptors whose states may be

**Commented [EO 1286681]:** In response to the comment above, the rule says that aligning the good neighbor emissions controls with the timing of implementation of nonattainment controls would be unworkable because it “would necessitate coordinating the activities of multiple states and the EPA regional and headquarters offices to a level of fine-tuning that effectively could preclude the implementation of good neighbor obligations altogether.” I understand how this approach would require burdensome coordination, but not how it “could preclude the implementation of good neighbor obligations altogether.” It would be helpful to explain this point in more detail.

**Commented [EPA82R81]:** Moved this discussion down in the response. Why this could preclude implementation altogether is expressed in the following sentence.



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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 at 9472-73 (evaluating claims regarding emissions reductions anticipated under Maryland's state law); 87 FR at 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.

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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, ~~the EPA’s review in this action~~, 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,<sup>131</sup> and the

<sup>131</sup>[https://edap.epa.gov/public/extensions/S4S\\_Public\\_Dashboard\\_2/S4S\\_Public\\_Dashboard\\_2.html](https://edap.epa.gov/public/extensions/S4S_Public_Dashboard_2/S4S_Public_Dashboard_2.html)

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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 ~~entirely~~ 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 ~~proposed-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 Agency also provides the design values for nonattainment and maintenance receptors and the predicted interstate contributions that are at or above the 1 percent of the NAAQS screening threshold.](#) The 2016 base period and 2023 and 2026 projected design values and contributions for all ozone monitoring sites are

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provided in the docket for this ~~proposed 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, AQM TSD in the docket for this ~~proposed~~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.<sup>132</sup> Additional information on the 2016-based air quality modeling platform can be found in the Air Quality Modeling Final Rule TSDAQM 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 performance statistics for a number of monitoring sites, particularly those in portions of

<sup>132</sup> Ramboll Environment and Health, January 2021, <http://www.camx.com>.

Commented [EO 1286683]: Which rule? This one?

Commented [EPA84R83]: Reference to proposed rule is an error. We have fixed the reference to the AQM TSD for this rule.

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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  $\pm$  15 percent and less than 25 percent, respectively (Emory, et.al., 2017).<sup>133</sup> 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 NOx 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](#).

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*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  $\geq$  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](#)~~AQM-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.,

<sup>133</sup> 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.

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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<sub>x</sub>, and contributions from transport of international anthropogenic emissions and natural sources into the U.S. Both biogenic and lightning NO<sub>x</sub> emissions in the U.S. dramatically increase from spring to summer.<sup>134,135</sup> 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.<sup>136,137</sup> To investigate the impacts of the sources, EPA conducted sensitivity model runs which focused on the effects on model performance of adding NO<sub>x</sub> 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<sub>x</sub> emissions and the updates to biogenic emissions, are described in Section IV.C of this notice.~~The development of lightning NO<sub>x</sub> emissions and the updates to biogenic emissions, as described in Section IV.C of this notice.~~ In the proposal modeling the

<sup>134</sup> Guenther, A.B., 1997. Seasonal and spatial variations in natural volatile organic compound emissions. *Ecol. Appl.* 7, 34–45. [http://dx.doi.org/10.1890/1051-0761\(1997\)007\[0034:SASVIN\]2.0.CO;2](http://dx.doi.org/10.1890/1051-0761(1997)007[0034:SASVIN]2.0.CO;2). Guenther, A., Hewitt, C.N., Erickson, D., Fall, R

<sup>135</sup> 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.

<sup>136</sup> 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 D C).* 2018;6(1):56. doi: 10.1525/elementa.309. PMID: 30364819; PMCID: PMC6198683.

<sup>137</sup> 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 18<sup>th</sup> Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 21-23, 2019.

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.<sup>138</sup> The outputs from this hemispheric modeling were then used to provide boundary conditions for national scale air quality modeling at proposal.<sup>139</sup> 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<sup>140</sup> were generally less biased.<sup>141</sup> 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 GEOSChem as an alternative to H-CMAQ for providing boundary conditions for the final rule modeling.

For the lightning NOx, biogenics, and GEOSChem sensitivity runs, EPA reran the proposal modeling using each of these inputs, individually. Results from these sensitivity runs

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<sup>138</sup> Mathur, R., Gilliam, R., Bullock, O.R., Roselle, S., Pleim, J., Wong, D., Binkowski, F., and 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.

<sup>139</sup> 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 [AQM-Air Quality Modeling Final Rule](#) TSD.

<sup>140</sup> 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.

<sup>141</sup> 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 PM2.5. Presented at the 21st Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 17-19, 2022.

indicate that each of the three updates provides an improvement in model performance. However, by far the greatest improvement in modeling performance is attributable to the use of GEOSChem. In view of these results EPA has included lightning NOx emissions, updated biogenic emissions, and international transport from GEOSChem 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 TSDAQM-TSD](#). For the air quality modeling supporting final SIP actions, model performance based on days in 2016 with measured MDA8 ozone  $\geq 60$  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.<sup>142</sup> In all regions, the 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.,  $< \pm 15$  percent for normalized mean bias and  $< 25$  percent for normalized mean error).<sup>143</sup> Additional information on model performance information is provided in the [Air Quality Modeling Final Rule TSDAQM-TSD](#). In summary, EPA included emissions of lightning NOx, as requested by commenters, and investigated and addressed concerns about model performance for the final rule modeling.

<sup>142</sup> A comparison of model performance from the proposal modeling to the final modeling for individual monitoring sites can be found in the docket for this final rule.

<sup>143</sup> 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.

**Commented [EO 1286685]:** In discussing improved modeling performance, the rule states, “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.” Even with the improved modeling, EPA admits that there are under predictions, so the commenter’s concerns are not fully resolved. EPA should consider explaining why under predictions generally are acceptable

**Commented [EPA86R85]:** There is no expectation that any air quality modeling will exactly match the corresponding measured data. As described in the Air Quality Modeling TSD, model performance statistics for EPA final rule modeling are within model performance benchmarks offered in recent peer-reviewed publications.



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### 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<sup>144</sup>.

<sup>144</sup> See Preparation of Emissions Inventories for the 2016v3 North American Emissions Modeling Platform TSD 2016v3 Emissions Modeling TSD, also available at <https://www.epa.gov/air-emissions-modeling/2016v3-platform>.

## 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<sub>x</sub> emissions that resulted from lightning strikes. To address this, lightning NO<sub>x</sub> 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.<sup>145</sup> The 2016 emissions inventories for the U.S. primarily include data derived from the 2017

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<sup>145</sup> 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.

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National Emissions Inventory (2017 NEI)<sup>146</sup> 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<sub>x</sub> and SO<sub>2</sub> 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.

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<sup>146</sup> <https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-technical-support-document-tsd>

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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-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.<sup>147</sup> 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.

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<sup>147</sup> 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\\_](https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm-summer-2021-reference-case_)

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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.<sup>148</sup> 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<sub>2</sub>, NO<sub>x</sub>, directly emitted particulate matter, CO<sub>2</sub>, 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

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<sup>148</sup> Available at <https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6>

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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 notice.

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 ~~is deliberately conservative in its estimate of change in the power sector~~. 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. In other words, regardless of whether a stakeholder takes a more comprehensive view of the EGU future (IPM) or a more conservative view one only accounting for what is currently planned of change in the EGU fleet (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 10 percent of the total ozone-season NO<sub>x</sub> 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 NOx 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 ~~in its conservative approach~~ 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~~ ~~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

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Commented [EPA88887]: Added "approach."

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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<sub>x</sub> 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

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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.<sup>149</sup> While the report focuses on CO<sub>2</sub> rather than NO<sub>x</sub>, 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 ~~generally~~ 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<sub>x</sub> 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 notice, we

<sup>149</sup> “Emissions of Carbon Dioxide ~~In~~ the Electric Power Sector,” Congressional Budget Office. December 2022. Available at <https://www.cbo.gov/publication/58860>

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 ~~the updates to the non-EGU point source emissions from proposal include~~ a few sources being moved to the EGU inventory, ~~and~~ 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

**Commented [EO 1286689]:** Some redundant phrasing here

**Commented [EPA90R89]:** This seems to be an error from earlier tracked changes. We deleted the extraneous text.

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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<sup>150</sup> 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 2014NEI-based emissions were replaced with 2017NEI

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<sup>150</sup> [https://www.faa.gov/data\\_research/aviation/taf/](https://www.faa.gov/data_research/aviation/taf/)

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<sub>x</sub> 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<sub>x</sub> 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<sup>151</sup> 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~~ ~~the New Mexico~~ Administrative code 20.2.50<sup>152</sup> 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

<sup>151</sup> [http://www.wrapair2.org/pdf/WRAP\\_OGWG\\_2028\\_OTB\\_RevFinalReport\\_05March2020.pdf](http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf)

<sup>152</sup> <https://www.srca.nm.gov/parts/title20/20.002.0050.html>

**Commented [EPA91]:** We believe this deletion is an error and have added back the text of “the New Mexico” before “Administrative code.”

**Commented [EO 1286692]:** EPA states that it used MOVES to develop onroad mobile source emissions for states other than California. In reading Section IV.C.3-7 (which pertain to development of emissions inventories for different sources), it was unclear why EPA used this model instead of 2016v2. It may be helpful to explain why EPA used one model for certain inventories and another for others.

**Commented [EPA93R92]:** MOVES3 was used to develop both the proposed rule and final rule onroad emissions. In the final rule, there were a few corrections made to the configuration. The term “2016v2” encompasses all of the emissions used for the proposal modeling, not just onroad, and “2016v3” means all of the emissions for the final rule modeling.

The types of changes made from proposal (2016v2) to final (2016v3) for onroad are detailed in the 2016v3 Emissions Modeling TSD and may be too much detail for here, but in short they are:

For 2016v3 new starts were included for 20 Georgia counties, road type and hoteling changes in six states, inspection and maintenance updates in North Carolina and Tennessee and corrected emissions factors for combination trucks

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represented, along with buses that used compressed natural gas. The EPA 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 The VMT were held flat from 2019 to 2021 to account for pandemic impacts, and then projected. 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<sub>x</sub>, 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

**Commented [EO 1286694]:** EPA held the VMT “flat from 2019 to 2021 to account for pandemic impacts,” but the pandemic began in February/March of 2020. It may be beneficial to explain why the VMT was held flat for 2019. Relatedly, it seemed that the pandemic impacted other commercial transportation sectors, not just onroad mobile sources. But the rule does not state that pandemic impacts were taken account for other sources (e.g., Commercial Marine Vessels and Nonroad Mobile Sources). It may be beneficial to explain how the irregular emissions during the pandemic were taken into account.

**Commented [EPA95R94]:** We studied available information on VMT for recent years including the pandemic and found that the 2021 VMT were very similar to the 2019 VMT (<https://fred.stlouisfed.org/series/M12MTVUSM227NFWA>). So instead of growing continuously from 2019 (the latest county-level data we had available) to 2023 and 2026, we essentially did not grow the VMT for two years to allow for rebound. Our airport growth factors account for the downturn due to the pandemic, but not CMV or nonroad emissions because we did not have data available to reflect pandemic impacts and any projected rebound at the time the modeling was performed. I think we can stay silent on that given that we reflected the pandemic's impact on growth for the most impacted sectors.

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

**Commented [EO 1286696]:** The explanation regarding line haul locomotives seems cursory. From the explanation provided, it is unclear what EPA means when it says it applied factors to the base year emissions (e.g., what factors were applied, what was the base year, and how was that year selected), and EPA does not describe the recent historical trends that were taken into account.

**Commented [EPA97R96]:** Please see the Emissions Modeling TSD for information about line haul locomotives emissions. The TSD has been added as a reference, along with some pertinent information on the analytic year .

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and 2026 were developed by applying factors to the ~~base year 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 NOx, 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.<sup>153</sup>

Where comments were provided about projected control measures or 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

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<sup>153</sup> <https://doi.org/10.5194/acp-21-5079-2021>

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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.<sup>154</sup> 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<sup>155</sup> were used. NO<sub>x</sub> and VOC reductions that are co-benefits to the NSPS for RICE are reflected, along with Natural Gas Turbines and Process Heaters NSPS NO<sub>x</sub> controls and NSPS Oil and Gas VOC controls. The WRAP future year inventory was used for oil and natural gas

<sup>154</sup> [http://www.wrapair2.org/pdf/WRAP\\_OGWG\\_Report\\_Baseline\\_17Sep2019.pdf](http://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf)

<sup>155</sup> [http://www.wrapair2.org/pdf/WRAP\\_OGWG\\_2028\\_OTB\\_RevFinalReport\\_05March2020.pdf](http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf)

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~~2023, that site is excluded from further analysis under ~~the EPA’s good neighbor framework~~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.<sup>156</sup> 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*.<sup>157</sup> 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.

<sup>156</sup> See 86 FR 23078-79.

<sup>157</sup> 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)).

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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<sub>x</sub> 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.<sup>158</sup>

The Agency explained in the NO<sub>x</sub> 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 Agency explained in the NO<sub>x</sub> 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 counties that also measure nonattainment for the most recent period of available ambient data. The EPA separately identified maintenance receptors as those receptors that would have difficulty maintaining the relevant NAAQS in a scenario that accounts for historical variability in air quality at that

<sup>158</sup> 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).

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~~receptor. The variability in air quality was determined by evaluating the “maximum” future design value at each receptor 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.<sup>159</sup> 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 maximum projected 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. Therefore, applying this methodology in this rule, the EPA assessed the magnitude of the maximum projected design values for 2023 and 2026at2026 at each receptor in relation to the~~

<sup>159</sup> 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<sub>2.5</sub>, and Regional Haze, Research Triangle Park, NC.

~~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* ~~H.~~~~<sup>160</sup> That is, monitoring sites with a maximum design value that exceeds the NAAQS are projected to have maintenance problems in the future analytic years.<sup>161</sup>

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,

<sup>160</sup> ~~See 795 F.3d at 136.~~

<sup>161</sup> 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. The EPA does not propose to adopt the information or suggested analytical approaches in that memorandum in this proposed rule proposing FIPs.~~ 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.



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.<sup>162</sup>

*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). While the EPA has confidence in the reliability of the modeling for projecting air quality conditions and contributions in future years, 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

<sup>162</sup> 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.

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 ~~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, 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

**Commented [EO 1286698]:** Can EPA explain why it has confidence in this modeling despite differing from measured ozone levels? Does this have implications for EPA’s use of the models?

**Commented [EPA99R98]:** Our approach for projecting future ozone concentrations followed the recommendations in EPA’s modeling guidance. In this regard, the starting point for our model projections were the average and maximum measured design values in 2016, 2017, 2018 at individual monitoring sites. Nationwide, outside of California, there were 39 areas that had monitoring sites measuring nonattainment during this base period. Of these 39 areas, EPA’s modeling correctly predicted (when compared to 2021 and 2022 measured data) that 11 areas including, for example, the New York City area, Chicago, Dallas, Houston, and Denver will continue to have a nonattainment/maintenance problem and that 22 areas including, for example, Atlanta, Baltimore, Philadelphia, and St. Louis would not be receptor areas in 2023. That is, the modeling correctly predicted the attainment status for 33 of the 39 areas that measured nonattainment during the 2016-2018 base period. Of the 6 remaining areas, 1 area, Yuma which is currently measuring clean data, is predicted to be a maintenance receptor in 2023. The other areas, which are measuring nonattainment in 2021 and 2022, but are not projected to be receptors in 2023 are Cleveland, Las Vegas, Phoenix, San Antonio, and in Michigan along the western shoreline of Lake Michigan. Although there are currently more monitoring sites measuring nonattainment than predicted by the model, the fact that the modeling was able to correctly identify nearly all of the areas with continued nonattainment problems gives us confidence in our modeling for this action. In addition, it is important to keep in mind that we’re comparing model predictions based on emissions reductions through 2023 to measured data from 2021 and 2022. While the 2021 and 2022 data are the most recent available data, it is entirely possible that continued emissions reductions from fleet turnover and other on-the-books control programs will, barring unforeseen economic changes or meteorology, result in lower measured ozone concentrations in 2023 compared to 2021 and 2022.

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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. ~~The EPA’s analysis of these additional receptors further is explained in Section IV.D of this notice.~~

However, because we did ~~not identify this basis for receptor-identification at proposal, in this final not propose to apply this new and novel expansion of the basis for regulation under the good neighbor provision receptor identification methodology as the sole basis for finding an upwind state linked, in this~~ 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<sup>163</sup> 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

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<sup>163</sup> 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.

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when meteorology is more favorable than average for ozone formation. Because the base year for the air quality modeling used in this ~~proposed~~-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<sup>164</sup> surrounding the location of the monitoring site to calculate a Relative Response Factor (RRF) for that site.<sup>165</sup> 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

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<sup>164</sup> As noted in this section, each model grid cell is 12 x 12 km.

<sup>165</sup> 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 concentrations and the future year (e.g., 2023 model run) average ozone concentrations represents the relative response factor.

the “3 x 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).<sup>166</sup> 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 x 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 x 3” and “no-water” approaches are provided in the docket for this ~~proposed-final~~ rule. For this final rule, the EPA is

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<sup>166</sup> <https://www.mmm.ucar.edu/weather-research-and-forecasting-model>.

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relying upon design values based on the “no water” approach for identifying nonattainment and maintenance receptors.<sup>167</sup>

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.<sup>168</sup> 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 proposes to identify nonattainment receptors in this rulemaking as those sites that are violating the NAAQS based on current 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

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<sup>167</sup> Using design values from the “3 x 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 x 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 “~~no water~~ 3 x 3” approach because the average design value with the “3 x 3” approach is 71.2 ppb versus 70.5 ppb with the “no water” approach.

<sup>168</sup> 40 CFR Part 50, Appendix P to Part 50 – Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone.

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.<sup>169</sup>

Table IV.D-1 contains the 2016-centered<sup>170</sup> 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 TSDAQM 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

<sup>169</sup> 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 notice, the Agency is not making a determination in this action that these monitors are ozone transport receptors. With two exceptions, as described in Section IV.F of this notice, because of the limited transport problem at these monitors EPA does not include these monitors as receptors at Step 1 of this final rule.~~ 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.

<sup>170</sup> 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.



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Monitor ID	State	County	2016 Centered Average	2016 Centered Maximum	2023 Average	2023 Maximum	2021
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

\* 2022 preliminary design values are based on 2022 measured MDA8 concentrations provided by state air agencies to EPA’s Air Quality System (AQS), as of November 22, 2022.

**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

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\*2022 preliminary design values are based on 2022 measured MDA8 concentrations provided by state air agencies to EPA’s Air Quality System (AQS), as of November 22, 2022.

\*\*“N/A” is used to denote that there is no valid design value.

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).<sup>171</sup> 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 TSDAQM-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

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<sup>171</sup> 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 ~~proposed~~ [final](#) rule.

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).<sup>172</sup> Specifically, the EPA believes that monitoring sites with measured design values and 4<sup>th</sup> 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

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<sup>172</sup> 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 AQMTSD](#) for details).

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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

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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 notice).<sup>173</sup> 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 4<sup>th</sup> 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
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

<sup>173</sup> We have not conducted an analysis in this action to determine whether violating-monitor receptors may exist in California.

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Monitor ID	State	County	2023 Average	2023 Maximum	2021	2022 P*	2021 4th High	2022 P 4th High
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 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

**Commented [EO 12866100]:** Section IV.F. In explaining why it decided to keep the 1% threshold (as opposed to the 1ppb threshold floated in the prior guidance memo), it could be helpful for EPA to also make a deference argument for why courts should defer to EPA on how it determines whether an upwind state is contributing to downwind nonattainment. Something like: "given that the statute does not outline how to determine contribution of an upwind state, EPA has decided that it is reasonable to continue to use the 1% threshold."

**Commented [EPA101R100]:** See edits below.

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<sup>174</sup> to quantify the contribution of 2023 and 2026 base case NO<sub>x</sub> and VOC emissions from all sources in each state to the 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 run, the EPA tracked the ozone formed from each of the following tags:

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<sup>174</sup> As part of this technique, ozone formed from reactions between biogenic VOC and NO<sub>x</sub> with anthropogenic NO<sub>x</sub> and VOC are assigned to the anthropogenic emissions.

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- States – anthropogenic NO<sub>x</sub> and VOC emissions from each state tracked individually (emissions from all anthropogenic sectors in a given state were combined);
- Biogenics – biogenic NO<sub>x</sub> 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 2016v1 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<sub>x</sub> and VOC emissions in each state, individually. The contributions to ozone from chemical reactions between biogenic NO<sub>x</sub> and VOC emissions were modeled and assigned to the “biogenic” category. The contributions from wildfire and prescribed fire NO<sub>x</sub> 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.<sup>175</sup>

This same approach was applied to calculate contribution metric values at individual

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<sup>175</sup> 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.

monitoring sites for 2026.<sup>176</sup>

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 ~~proposed~~-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 TSDAQM-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

<sup>176</sup> 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.

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<b>Upwind State</b>	<b>Largest Contribution to Downwind Nonattainment Receptors</b>	<b>Largest Contribution to Downwind Maintenance-Only Receptors</b>
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

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Upwind State	Largest Contribution to Downwind Nonattainment Receptors	Largest Contribution to Downwind Maintenance-Only Receptors
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
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

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Upwind State	Largest Contribution to Downwind Nonattainment Receptors	Largest Contribution to Downwind Maintenance-Only Receptors
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

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<b>Upwind State</b>	<b>Largest Contribution to Downwind Violating Monitor Maintenance-Only Receptors</b>
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
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

Upwind State	Largest Contribution to Downwind Violating Monitor Maintenance-Only Receptors
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 TSDAQM 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](#)

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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<sub>2.5</sub> 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.<sup>177</sup> 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

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<sup>177</sup> See Final CSAPR Update Air Quality Modeling TSD, at 27–30 (EPA–HQ–OAR–2015–0596–0144). See also 86 FR 23054, 23085.



memorandum stated that “it may be reasonable and appropriate” for states to rely on an alternative 1 ppb threshold at Step 2.<sup>178</sup> (The memorandum also indicated that any 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 notices 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.<sup>179</sup> 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

**Commented [EO 12866102]:** EPA states that based on “several notices proposing transport SIP disapprovals,” it believes “it may not be appropriate to continue to attempt to recognize alternative contribution thresholds...” While it’s probably fine to cross-reference, the paragraph below succinctly summarizes why allowing a 1 ppb threshold would be “impractical,” so it may be beneficial to do the same here and summarize those notices where EPA explains why it would be inappropriate because this 1% threshold issue will likely be litigated.

**Commented [EPA103R102]:** Our final position with respect to the SIP disapproval action is stated in that FR notice. We believe the description in this section is sufficient, but happy to discuss further if needed.

<sup>178</sup> August 2018 memo at 4.

<sup>179</sup> 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.

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

**Commented [EO 12866104]:** EPA states that the “1 ppb threshold has the disadvantage of losing a certain amount of total upwind contribution for further evaluation at Step 3,” but I did not find that EPA had explained how that would occur.

**Commented [EPA105R104]:** This is discussed later in the response. We cite the amount lost on a nationwide basis in each of three rounds of modeling (7% (2011-base), 5% (2016v2), 5% (2016v3)). This summarizes the proposal and we do not believe an edit is needed here.

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. ~~Commenters have not established that this approach is either unlawful or arbitrary and capricious.~~ We do not agree that this approach is inconsistent with or a reversal in policy from the August 2018 memorandum, which ~~was not binding rulemaking action in any case, and~~ 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 of the notice)~~ 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 ~~only~~ 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, ~~those the~~ states in this rule with contributions that fall between 0.70 ppb and 1 ppb are ~~Iowa, 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

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contribution between 0.70 ppb and 1 ppb are Kentucky, Nevada, and Oklahoma, ~~and Nevada~~.  
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 ~~much of~~ the ozone transport problem being analyzed in this rule is still the result of the collective impacts of emissions from multiple upwind contributors ~~states~~. 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~~ contributors yet is not so

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large that it unfairly focuses attention for further action only on the largest single or few upwind ~~contributors~~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* ~~81 FR 74504, 74518. *See also*~~ 86 FR 23054, 23085; 81 FR 74504, 74518; 76 FR 48,208, 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 minimis*” 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.”<sup>180</sup> It interpreted “that information to make recommendations about what thresholds *may* be appropriate for use in” SIP submissions (emphasis added).<sup>181</sup> 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*

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<sup>180</sup> August 2018 memorandum, at 1.

<sup>181</sup> *Id.*

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).<sup>182</sup> 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.”<sup>183</sup> Further, the August 2018 memorandum said that “EPA and air agencies should consider whether the recommendations in this guidance are appropriate for each situation.”<sup>184</sup> 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

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<sup>182</sup> *Id.* at 4.

<sup>183</sup> *Id.* at 1.

<sup>184</sup> *Id.*

~~ppb or other alternative thresholds would in fact be acceptable.~~ Although the EPA ~~explained 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.”<sup>185</sup> The EPA is not formally rescinding the ~~2018~~ 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~~ Fox v. FCC v. Fox factors below.

~~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. The Agency has not imposed a requirement that states must use a 1 percent of the NAAQS threshold (which would reflect a change in position from the August 2018 memorandum).~~

<sup>185</sup> 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).

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Rather, under the terms of the August 2018 memorandum, the Agency has found that individual states have not made a sufficient showing that the use of an alternative contribution threshold is justified for those states. But even if it were found that the Agency's position had fundamentally changed between this rulemaking action and the August 2018 memorandum (which we do not concede to be the case), we do not believe that any party had a legitimate 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. First, neither states nor the emissions sources located in those states have incurred any compliance costs based on the August 2018 memorandum. Second, it is not clear that any states invested much of their own public resources in developing state-specific arguments in support of a 1 ppb threshold. As EPA observed in proposing to disapprove the SIPs, "[I]n nearly all submittals, the states did not provide the EPA with analysis specific to their state or the receptors to which its emissions are potentially linked. In one case, the proposed approval of Iowa's SIP submittal, the EPA expended its own resources to attempt to supplement the information submitted by the state, to more thoroughly evaluate the state-specific circumstances that could support approval. It was at the EPA's sole discretion to perform this analysis in support of the state's submittal, and the Agency is not obligated to conduct supplemental analysis to fill the gaps whenever it believes a state's analysis is insufficient. The Agency no longer intends to undertake supplemental analysis of SIP submittals with respect to alternative thresholds at Step 2 for purposes of the 2015 ozone NAAQS." See, e.g., 87 FR 9806-07 (emphasis added).

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~~Although the EPA is not formally revoking the August 2018 memorandum at this time,~~  
~~We~~ continue to believe, as set forth in our proposed action, that national ozone transport policy is not well served by 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.<sup>186</sup> 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

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<sup>186</sup> 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.

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 ~~no actual reasoning has been supplied 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

**Commented [EO 12866108]:** Is it inconsistent for EPA to reference back to the 2018 memorandum here, since the prior few pages explained why EPA is not bound by it?

**Commented [EPA109R108]:** We have modified language earlier in this section in response to this comment but we do not believe this reference is inconsistent.

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collective contribution problem with respect to ozone, we continue to find no compelling policy  
~~imperative justifies moving reason to adopt a new threshold for all states of to a 1 ppb threshold.~~

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,<sup>187</sup> 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

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<sup>187</sup> *See* 86 FR 23054, 23058 (April 30, 2021).

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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 notice 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 with respect to the more protective 2015 ozone NAAQS. While Arizona and Oregon’s interstate transport obligations for

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~~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.~~

~~We are finalizing this determination in Section IV.G of this notice, but it is on the basis of our conclusion that specific monitors in California are not interstate transport “receptors” at Step 1, based on evaluating the total upwind state contribution to those monitors, not an alternative Step 2 threshold applied to a single upwind state. See 87 FR at 20074-20075. In 2016, the EPA previously 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). To the extent there was any lack of clarity in the reasoning with respect to the EPA’s action on Arizona’s 2008 ozone transport SIP, we clarify here that we consider the treatment of certain California monitoring sites to be a Step 1 issue, not an alternative approach 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

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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 erves 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.

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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 at 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



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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*,

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*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<sub>2.5</sub>. 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 legitimate 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 at 9373 (reviewing reliance in the context of the SIP-disapproval action).

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

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*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, ~~Oregon~~, Rhode Island, South Carolina, South Dakota, Vermont, and Washington.<sup>188</sup> 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 ~~proposed~~ final rule. Additionally,

<sup>188</sup> The status of monitoring sites in California to which Oregon may be linked is under review. See Section IV.G.

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the EPA has made final determinations that two states outside the modeling domain for the air quality modeling analyzed in this ~~proposed-final~~ rulemaking – Hawaii<sup>189</sup> and Alaska<sup>190</sup> – 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 further~~ 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

<sup>189</sup> The EPA approved Hawaii’s 2015 ozone transport SIP on December 27, 2021. *See* 86 FR 73129.

<sup>190</sup> The EPA approved Alaska’s 2015 ozone transport SIP on December 18, 2019. *See* 84 FR 69331.

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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 TSDAQM-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.<sup>191</sup> 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.<sup>192</sup> ~~The EPA is deferring finalizing a finding at this time for Oregon (see Section IV.G of this notice for additional information). For these three states, the EPA does not find any case-specific circumstances that would warrant not treating these states as linked for purposes of this action.~~

<sup>191</sup> 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.

<sup>192</sup> See 81 FR 71991 (October 19, 2016), 82 FR 9155 (February 3, 2017).

In the EPA’s current analysis, the EPA finds that for one state—Oregon—the same considerations that led it to approve another state’s SIP submission, Arizona’s, for the 2008 ozone NAAQS apply to Oregon’s circumstances for the 2015 ozone NAAQS. As explained in the following section, the EPA therefore affirms 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 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

**Commented [EO 12866114]:** The rule states “We note that our updated modeling for this final rule shows that two states, Minnesota and Wisconsin, that we found linked in 2026 in the proposal are no longer projected to be linked in that year but are linked in 2023.” I think it would be prudent to explain this change in a bit more detail, as it is a shift from the proposed rule.

**Commented [EPA115R114]:** See footnote added to this sentence.

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proposal are no longer projected to be linked in that year but are linked in 2023.<sup>193</sup> 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 ~~Receptors~~ 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.<sup>194</sup> At proposal, the EPA explained that ~~that~~ our analysis of the nature of the air quality problem at these monitoring sites

**Commented [EO 12866116]:** Why does EPA not consider these ozone transport receptors?

**Commented [EPA117R116]:** Flagging for further discussion

<sup>193</sup> 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.

<sup>194</sup> 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. Monitors are listed in the AQM TSD included in the docket for this rulemaking. While EPA is providing information about cumulative upwind contribution to the California monitors, the Agency does not consider these monitors as ozone transport receptors.

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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 its 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.<sup>195</sup> 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.”<sup>196</sup> 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.”<sup>197</sup> 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.<sup>198</sup>

~~We are finalizing our proposed finding that the monitoring sites in California to which Oregon is modeled to contribute greater than 0.7 ppb are not “receptors” at Step 1 for purposes of interstate transport obligations for the 2015 ozone NAAQS. In the 2016v3 modeling, the~~

<sup>195</sup> 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule).

<sup>196</sup> 81 FR at 15203.

<sup>197</sup> *Id.*

<sup>198</sup> *Id.*



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~~highest percent of the total cumulative ozone contribution from upwind states to any of these California sites is 1.4 percent.<sup>199</sup> This is lower than the largest upwind state transport contribution relative to total ozone at the California sites identified in the EPA’s approval of Arizona’s 2008 ozone transport SIP (4.4 percent).<sup>200</sup> Further, as was the case for the sites in California analyzed in the EPA’s Arizona action, the identified sites in California each have only one upwind state contributing to them by 1 percent of the NAAQS or more (Oregon). These conditions (i.e., very low total upwind contribution and only one upwind state that contributes at or above 1 percent of the NAAQS) are not met for any other nonattainment or maintenance receptors in the country.~~

*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.

<sup>199</sup> See Air Quality Modeling Final Rule TSD AQM TSD in the docket for this action.

<sup>200</sup> ~~81 FR at 15203; 81 FR 31513.~~

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*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. The EPA finds that these monitoring sites should not be considered receptors for the purpose of assessing 2015 ozone NAAQS interstate transport obligations. The EPA is not using a different contribution threshold at Step 2 for Oregon or for Western states generally, nor does the EPA reach its conclusion based on any evaluation at Step 3 of emissions reduction opportunities in Oregon.

At proposal, we pointed out that California receptors are heavily impacted by in-state emissions. While that may be true, we clarify in this final rule that the basis for our determinations with respect to these sites is not the level of in-state contribution but rather the fact that the contribution from upwind states is so low. The elevated ozone levels at these sites may be attributable to biogenic emissions, international emissions, or boundary conditions, in addition to in-state anthropogenic emissions. Our proposal was not intended to suggest that a certain level of in-state anthropogenic emissions influenced our treatment of these sites under the

~~good neighbor provision. Rather, the critical point is that the total level of impact from upwind states at these California sites is so low. The 4 step framework that the Agency has applied to address interstate ozone transport is informed by the “collective contribution” problem observed throughout many areas of the country—i.e., the fact that total ozone levels are the result of many small contributors over a wide geographic area. That approach generally continues to make good sense throughout most of the country based on our air quality and contribution analysis to date and in this final rule. A limited circumstance, which we previously observed with respect to certain California sites in acting on Arizona’s 2008 ozone NAAQS good neighbor SIP, presents the exception. Where total contribution from upwind states is as low as 1.4 percent and only one state contributes above 1 percent of the NAAQS, that monitoring site does not in the EPA’s view suffer from an interstate contribution problem. Although commenters claim that this same consideration could be applied at other receptors across the country to reach the same conclusion (i.e., eliminate other receptors outside California at Step 1), EPA notes that we have evaluated this same information across all receptors, and, as previously stated, nowhere else do we project such a low total upwind contribution and with only a single upwind state contributing at or above one percent of the NAAQS.~~

~~It is not necessary to establish a bright line threshold in making this determination. As we noted at proposal, the level of total upwind state impact at the California monitoring sites at issue here is less than the amount for which we issued a similar determination in acting on Arizona’s SIP. Thus, the determination is consistent with that precedent. Nor does it matter that there are several monitoring sites in California for which this circumstance exists. The same observation~~

~~can be made for each one of these sites: the level of total upwind state contribution is small enough that they should not be considered interstate transport receptors.~~

~~As a consequence of this finding, the EPA continues to find that ozone precursor emissions from Oregon do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any downwind state, because the total collective upwind state ozone contribution to these California monitoring sites is extremely low compared to the contribution levels typically addressed under the good neighbor provision for ozone; these sites are not considered receptors at Step 1. Therefore, this action does not change the EPA's prior approval of Oregon's SIP. The EPA is not promulgating any new FIP requirements and is not requiring reductions from new or existing EGU or non-EGU sources in Oregon in this action.~~

## **V. Quantifying Upwind-State NO<sub>x</sub> 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 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<sub>x</sub> 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<sup>201</sup>— to evaluate increasing levels of uniform NO<sub>x</sub> 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<sub>x</sub> control stringency that would eliminate significant contribution to downwind nonattainment or maintenance receptors. The selection of a uniform level of NO<sub>x</sub> 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<sub>x</sub> control stringency; (2) evaluate potential NO<sub>x</sub> 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<sub>x</sub> emissions reductions, and downwind air quality

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<sup>201</sup> See CSAPR, Final Rule, 76 FR 48208 (August 8, 2011).

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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 notice, 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub>-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<sub>x</sub> 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 notice describes the available NO<sub>x</sub> emissions controls that the EPA evaluated for this final rule and their representative cost levels

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(in 2016\$). Section V.C of this notice discusses EPA’s application of that information to assess emissions reduction potential of the identified control stringencies. Finally, Section V.D of this notice 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 notice.

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<sub>x</sub> 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 compared to other industrial source categories.

Since the NO<sub>x</sub> 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<sub>x</sub> emissions reduction opportunities at relatively commensurate cost per ton levels, and these



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emissions reductions will make a meaningful improvement in air quality at the downwind receptors. Section V.B.2 of this notice 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<sub>x</sub> 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.<sup>202</sup> For further discussion of EPA's existing and ongoing mobile source measures, *see* Section V.B.4 of this notice.

#### *B. Identifying Control Stringency Levels*

##### 1. EGU NO<sub>x</sub> Mitigation Strategies

In identifying levels of uniform control stringency for EGUs, the EPA assessed the same NO<sub>x</sub> 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<sub>x</sub> removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO<sub>x</sub> combustion controls; (3) fully operating existing SNCRs, including both optimizing NO<sub>x</sub> 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<sub>x</sub> emitting or zero-emitting EGUs may occur in response to economic factors. As the cost of emitting NO<sub>x</sub> increases, it becomes increasingly cost-effective for units with lower NO<sub>x</sub> rates to increase generation, while units with higher NO<sub>x</sub> rates reduce

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<sup>202</sup> 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.

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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> allowance price declined, NO<sub>x</sub> 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.<sup>203</sup> The EPA determined in the Revised CSAPR Update that optimizing SCRs was a

<sup>203</sup> See “Ozone Season Data 2018 vs. 2019” and “Coal-fired Characteristics and Controls” at <https://www.epa.gov/airmarkets/power-plant-data-highlights#OzoneSeason>.

readily available approach for EGUs to reduce NO<sub>x</sub> 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<sub>x</sub> Mitigation Strategies Final Rule TSD for this rule describes a range of cost estimates for 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<sub>x</sub> reduction reagent in SCR systems. Depending on a unit’s control operating status, the representative cost at the 90<sup>th</sup> 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

**Commented [EO 12866118]:** In defending the \$1,600 per ton marginal cost of optimizing SCR controls, the rule states, “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.” To fend off challenges that EPA should have picked a lower marginal cost, EPA should explain why it is was appropriate for EPA to use this price estimate.

**Commented [EPA119R118]:** Added language.

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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 90<sup>th</sup> 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<sub>x</sub> Mitigation Strategies Final Rule TSD and accompanying documents.<sup>204</sup> 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<sub>x</sub> reduction potential from optimizing, the EPA considers the difference between the non-optimized NO<sub>x</sub> emissions rates and an achievable operating and optimized SCR NO<sub>x</sub> emissions rate. To determine this rate, EPA evaluated nationwide coal-fired EGU NO<sub>x</sub> ozone season emissions data from 2009 through 2019 and calculated an average NO<sub>x</sub> 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

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<sup>204</sup> 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).

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second-lowest ozone season NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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.<sup>205</sup> 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

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<sup>205</sup> In the 22-state CSAPR Update region, 2005 EGU NO<sub>x</sub> 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<sub>x</sub> rates that were less than 0.12 lb/mmBtu and 2005 average non-ozone season NO<sub>x</sub> emissions rates that exceeded 0.12 lb/mmBtu and where the average non-ozone season NO<sub>x</sub> rate was more than double the ozone season rate.

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ozone season based on reported 2021 and 2022 emissions rates. Notably, the higher ozone season NO<sub>x</sub> 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. 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> (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, ~~conservative~~ underestimate the control's



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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<sub>x</sub> 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<sub>x</sub> 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

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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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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

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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<sub>x</sub> emissions rates in this analysis, these EGUs had relatively low NO<sub>x</sub> emissions rates at mid- and high-operating levels; moreover, there was little variability in NO<sub>x</sub> emissions rates at these operating levels. However, during the 2019 ozone season, these EGUs had higher NO<sub>x</sub> emissions rates and greater variability in NO<sub>x</sub> emissions rates across operating levels than in the past, particularly at mid-operating levels.”<sup>206</sup> 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.

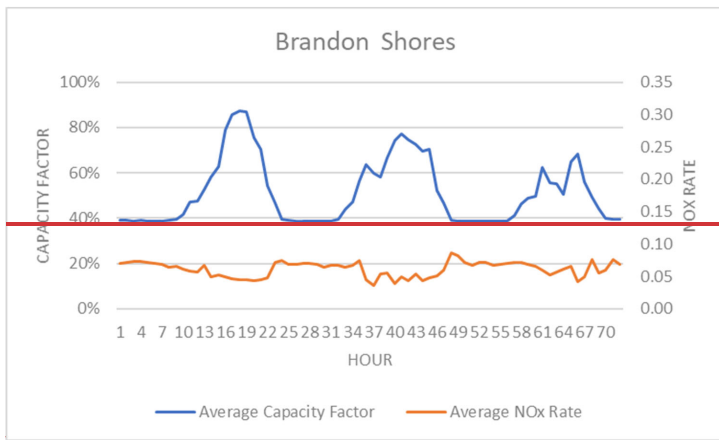
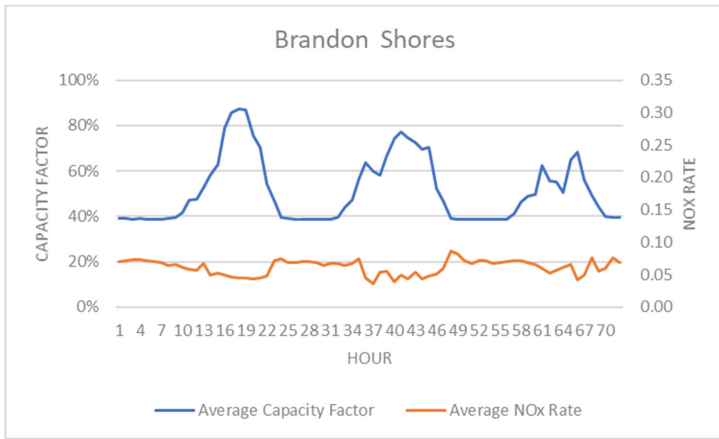
Some commenters have alleged that in recent years coal-fired EGUs have declined in capacity factor and that SCR performance declines at those lower operating levels. However, hourly data indicate that maintaining consistent SCR performance at lower capacity factors is possible. For example, the unit-level performance data in Figure 2 to Section VI.B of this notice 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.<sup>207</sup>

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

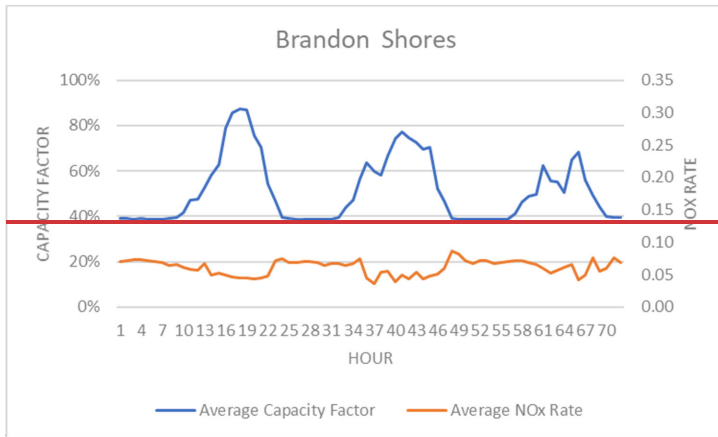
<sup>206</sup> “Analysis of Ozone Season NO<sub>x</sub> Emissions Data for Coal-Fired EGUs in Four Mid-Atlantic States,” EPA Clean Air Markets Division. December 2020. Available at [https://www.epa.gov/sites/production/files/2020-12/documents/184c\\_emission\\_data\\_tsd.pdf](https://www.epa.gov/sites/production/files/2020-12/documents/184c_emission_data_tsd.pdf).

<sup>207</sup> EPA, *Air Markets Program Data*. Available at [www.epa.gov/ampd](http://www.epa.gov/ampd).

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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 NOx 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

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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 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 RCU rule’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<sub>x</sub> 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<sub>x</sub> 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 ~~price spikes~~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<sub>x</sub> Mitigation Strategies Final Rule TSD further addresses

**Commented [EO 12866120]:** In responding to a comment that the marginal cost of optimizing SCR controls is too low, the rule states, “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.” A further explanation of why a higher cost would not change EPA’s determination could be helpful—for example, is this because SCR controls are the easiest mitigation measure to take?

**Commented [EPA121R120]:** Added sentence.



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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 ~~entirely~~ 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<sub>x</sub> 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<sub>x</sub> burners (LNB) and over-fire air (OFA) can be installed or updated quickly and can substantially reduce EGU NO<sub>x</sub> 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<sub>x</sub> emissions rate assumptions for upgrading existing combustion controls to state-of-the-art combustion control. The EPA is maintaining its determination that NO<sub>x</sub> emissions rates of 0.146 to 0.199 lb/mmBtu can be achieved on average depending on the unit’s boiler configuration,<sup>208</sup> and, once installed, reduce NO<sub>x</sub> emissions at all times of EGU operation.

These assumptions are consistent with the Revised CSAPR Update. They are further discussed in the EGU NO<sub>x</sub> 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 all

<sup>208</sup> Details of EPA’s assessment of state-of-the-art NO<sub>x</sub> combustion controls are provided in the EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD.

**Commented [EO 12866122]:** Can EPA clarify whether this means that some boiler configurations will not be able to achieve these emissions rates?

**Commented [EPA123R122]:** Added clarifying text. EPA believes that boilers can achieve these rates, but as noted in the below paragraph, in the case of a tangential boiler burning bituminous coal – the 0.146 lb/mmBtu may not be attainable. Therefore, we are using 0.199 lb/mmBtu for both boiler types which we believe is attainable regardless of coal choice.

~~unit types 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-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).<sup>209</sup> 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.<sup>210</sup> 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

<sup>209</sup> 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.

<sup>210</sup> EPA-HQ-OAR-2015-0500-0093.

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- 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<sub>x</sub> emissions by the start of the 2024 ozone season. More details on these analyses can be found in the *EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD*.

The cost of installing state-of-the-art combustion controls per ton of NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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

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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 NOx emissions rates. The commenters claim EPA’s assumptions are derived from projected NOx emissions rates based on ideal circumstances for NOx 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 rates 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 NOx 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, and/or, It also assessed whether the rate had been demonstrated by both subbituminous and bituminous coal units with state-of-

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Commented [EPA125R124]: Corrected typo.

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~~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. It also ensured rate had been demonstrated by both subbituminous and bituminous coal units with state-of-the-art combustion controls.~~ 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<sub>x</sub> 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<sub>x</sub> emissions (with sufficient reagent). They are less capital intensive but less efficient at NO<sub>x</sub> 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 ~~with identified EGU reductions in their proposed FIP~~, approximately 11 percent of coal-fired EGU capacity is equipped with SNCR.<sup>211</sup> 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

<sup>211</sup> <https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6>

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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.<sup>212</sup>

The EPA determined that optimizing already operating SNCRs or turning on idled SNCRs is an available approach for EGUs to reduce NO<sub>x</sub> 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 control measure is available beginning in the 2023 ozone season.

Using the Retrofit Cost Analyzer described in the *EGU NO<sub>x</sub> 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

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<sup>212</sup> See “Historical Emission Rates for Units with SNCR Optimization Potential” in the docket for this rulemaking.

achieve a 25 percent NO<sub>x</sub> reduction on average. New SNCR technology provides owners with a relatively less capital-intensive option for reducing NO<sub>x</sub> 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.<sup>213</sup> Given these observations, the EPA identifies this technology as an emissions reduction measure for coal units less than 100 MW lacking post-combustion NO<sub>x</sub> control technology. As described in the *EGU NO<sub>x</sub> 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<sub>x</sub> control technology have overwhelmingly chosen SCRs over SNCRs. Even for smaller units less than 100 MW identified

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<sup>213</sup> See *EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD* for additional discussion.



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

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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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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

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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 rapidly due to a lack of economies of scale.<sup>214</sup>

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.<sup>215</sup>

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,

<sup>214</sup> IPM Model-Updates to Cost and Performance for APC Technologies. SCR Cost Development Methodology for Coal-fired Boilers. February 2022.

<sup>215</sup> *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/P1001G00.pdf>.

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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 notice.

The Agency examined the cost for retrofitting a coal unit with new SCR technology, which typically attains controlled NO<sub>x</sub> rates of 0.05 lb/mmBtu or less. These updates are further discussed in the EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD.<sup>216</sup> Based on the characteristics of coal units of 100 MW or greater capacity that do not have post-combustion

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<sup>216</sup> 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.

NOx control technology, the EPA estimated a weighted-average representative SCR cost of \$11,000 per ton.<sup>217</sup>

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.<sup>218</sup> 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,

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<sup>217</sup> 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 NOx Mitigation Strategies Final Rule TSD for more discussion.

<sup>218</sup> See "IPM Model – Updates to Cost and Performance for APC Technologies: SCR Cost Development Methodology for Coal-fired Boilers"

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<sub>x</sub> ozone season emissions data from 2009 through 2021 and calculated an average NO<sub>x</sub> 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.<sup>219</sup> For this segment of the oil/gas steam units lacking post-combustion NO<sub>x</sub> 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

<sup>219</sup> 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.

**Commented [EO 12866126]:** EPA could consider expanding this summary to more clearly detail the "valid technical concerns" that merited changes to the final rule

**Commented [EPA127R126]:** Added cross-references to existing discussions in preamble Sections VI.B.2.a and the EGU NO<sub>x</sub> Mitigation Strategies TSD.

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collective volume of SCR installation occurring in 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 ~~valid technical~~ 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 ~~unprecedented-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 NOx 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-which fully extends the flexibilities of a trading programs for compliance purposes for any outlier units unable to complete the retrofit during that time frame](#). These adjustments continue to incentivize

reductions in NOx 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.<sup>220</sup> 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.

<sup>220</sup> 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.

**Commented [EO 12866128]:** It could be helpful to cross-reference EPA’s RIA appendix here so that it’s clear EPA accounted for these changes to some degree in the baseline, and caveat in the text the extent to which these are not captured in the estimated benefits (if true)

**Commented [EPA129R128]:** Footnote added.

**Commented [Round 2130R128]:** 3/9/2023: Please add some discussion to the footnote to summarize the extent to which these IRA changes are not captured in the estimated benefits (if true)

**Commented [EPA131R128]:** Updated the text in the footnote below.



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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 in outlier cases of project timing that would not be representative of the conditions expected at future retrofit projects.<sup>221</sup>

*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.

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<sup>221</sup> 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>

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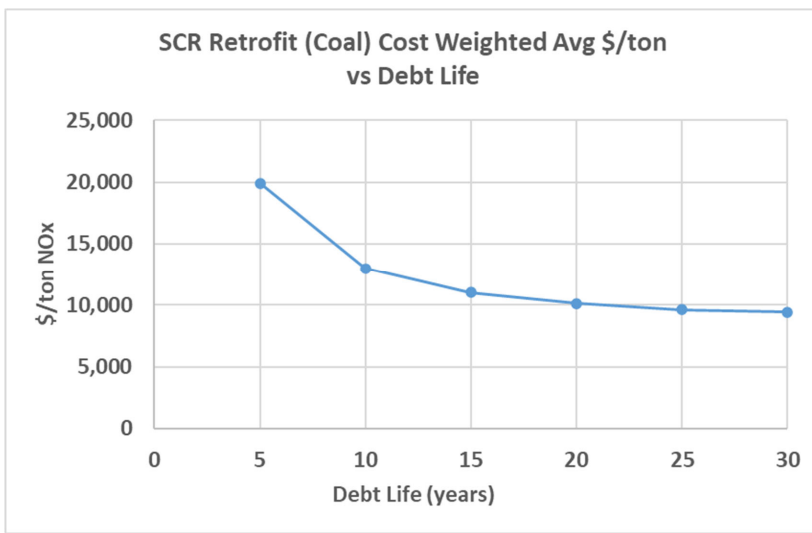
*Response:* EPA analysis of SCR retrofit cost reflects a representative value for the technology based on a weighted average cost. The underlying data and the discussion in the EGU NO<sub>x</sub> Mitigation Strategies Final TSD illustrates that these costs can vary significantly at the unit level based 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 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

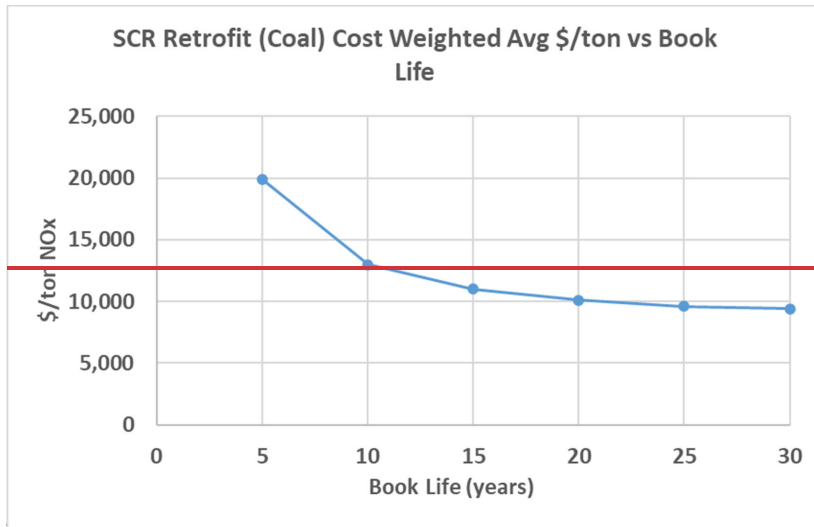
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terms of generating capacity) has no planned retirement date within 15 years, and therefore the cost of pollution control technology on such units would likely be lower, holding all other parameters equal, on a dollar per ton basis by virtue of the 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<sub>x</sub> 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 notice.

Figure 1 to Section V.B.1.e: SCR Retrofit Cost Weighted Average \$/ton vs Debt  
Life<sup>222</sup>



<sup>222</sup> “Debt Life” refers to the term length, or duration, for a loan used to finance the retrofit.



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 ~~entirely~~ 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

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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<sub>x</sub> 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~~ ~~material~~ and personnel that could be used for more advanced clean-technology 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~~ ~~does not force these units to retrofit to continue to operate~~, so long as they comply with the mass-based emissions trading program requirements.<sup>223</sup> 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

<sup>223</sup> ~~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. As noted in the *Final EGU NO<sub>x</sub> Mitigation Strategies* EPA has conducted a technical evaluation of whether the mass based budgets that are premised on retrofit of SCR technology may complied with through other strategies, and finds that they are readily achievable through those other strategies.~~

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 notice.

*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 ~~more than~~ 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

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retrofit projects. Current SCR catalyst suppliers provide NO<sub>x</sub> 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<sub>x</sub> removal rates. Standard commercial terms, made by the purchaser to the SCR Retrofit supplier, can specify a system capable of meeting the proposed NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Mitigation](#)



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Strategies Proposed Rule TSD” (Feb. 2022), hereinafter referred to as the EGU NO<sub>x</sub> Mitigation Strategies Proposed Rule TSD, Proposed and the EGU NO<sub>x</sub> Mitigation Strategies Final TSDs 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~~ analysis are discussed and shown in Appendix B of the EGU NO<sub>x</sub> 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 VI.D of this notice, 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.

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*Comment:* Some commenters suggested that EPA’s proposed representative cost for SCR pollution control is likely ~~too high conservative~~ 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 conservative as it~~ 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 ~~both reasonable and conservative~~. 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 volatility among these metrics, EPA believes its ~~conservative~~ 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, ~~than~~ 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<sub>x</sub> 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<sub>x</sub> increases, it becomes increasingly cost-effective for units with lower NO<sub>x</sub> rates to increase generation, while units with higher NO<sub>x</sub> 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<sub>x</sub>-control levels.

The EPA recognizes that imposing a NO<sub>x</sub>-control requirement on affected EGUs, like any environmental regulation, internalizes the cost of their pollution, which could result and inevitably results 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 at

74544-45; 76 FR at 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 and maintains that the. The EPA does have continues to believe it has authority under CAA section 110(a)(2)(D)(i)(I) this section of the Clean Air Act to consider and require emissions reductions from generation shifting if the EPA were to find that generation shifting strategy was necessary to eliminate significant contribution under CAA section 110(a)(2)(D)(i)(I). However, based on specific 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 exercising its policy discretion not to specify ing discrete emissions reduction potential from generation shifting as a part of the Step 3 analysis, nor to require any specified 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

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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 notice, 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 notice 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<sub>x</sub> control strategies. *See, e.g.*, 81 FR at 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<sub>x</sub> 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

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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<sub>x</sub> Mitigation technologies should be required to eliminate significant contribution. For instance, the EGU NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions in 2021). EPA analysis estimates a representative cost of \$22,000 per ton for dry low NO<sub>x</sub> burners or ultra-low NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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.<sup>224</sup>

<sup>224</sup> The memorandum is available in the docket here:  
<https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150>.

**Commented [EO 12866134]:** Section V.B.2. It does not appear that the final rule explains how EPA came to use the \$7,500/ton threshold for non-EGUs. A more fulsome explanation may be beneficial.

**Commented [EPA135R134]:** We included an explanation below.

**Commented [EO 12866136]:** EPA should better explain why it focused its screening on units with >100 tpy. There isn't much on that in the preamble, and the previous Screening memo only said EPA believes smaller units may be well controlled and further reductions may be more costly. EPA should explain why it believes those things to be true.

**Commented [EPA137R136]:** Please let us know if the request is to include any of the content below in the preamble text.

The use of the >100 tpy of NO<sub>x</sub> emissions unit size threshold in the Non-EGU Screening Assessment was a reasonable way to identify industries with emissions units that would be "more likely" to have cost-effective emissions reduction potential. We explained in the Non-EGU Screening Assessment:

We focused on assessing emissions units that emit >100 tpy of NO<sub>x</sub>. 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.

The purpose of this emissions unit size threshold was not definitively to exclude all emissions units with less than 100 tpy emissions from being subject to emissions control requirements in this rule, nor was this step in the analytical exercise intended to function as a definitive applicability criterion. The purpose was to allow the Agency to focus on those emissions units "more likely" to have cost-effective emissions control opportunities, before proceeding to conduct further analysis on appropriate emissions controls.

**Commented [Round 2138R136]:** 3/9/2023: It might be helpful to explain in the preamble that sources <100tpy are likely to include smaller sources, for which controls may be relatively more burdensome, as well as sources that already have some controls that have brought them to under 100tpy. EPA is therefore exercising its discretion to focus on >100tpy at this stage, to focus first on those relatively larger sources that may not have yet installed cost-effective controls. But defer to EPA if that addition would create any problems.

**Commented [EPA139R136]:** We have added this information as request in Section VI.C where we discuss the applicability thresholds and the basis for them.

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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.<sup>225</sup>

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 notice. Tables I.B-2 through I.B-7 in Section I.B of this

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<sup>225</sup> The TSD for the proposed FIP is available in the docket here:  
<https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145>.

notice identify the emissions units and applicable emissions limitations, and Table II.A-1 in Section II.A of this notice identifies the industries included in the final rule.

For the final rule, to determine NO<sub>x</sub> 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.<sup>226</sup> 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.<sup>227</sup> We did not run the Control Strategy Tool to estimate emissions reductions and costs and instead programmed the assessment using R.<sup>228</sup> 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),<sup>229</sup> the EPA estimated NO<sub>x</sub> 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)

**Commented [EO 12866140]:** EPA “did not run the Control Strategy Tool to estimate emissions reductions and costs and instead programmed the assessment using R,” but did not explain why this approach was taken. It may be beneficial to explain why EPA took this course of action.

**Commented [EPA141R140]:** The EPA’s CoST software does not allow for the *on-the-fly* correction of information about sources/units that was warranted due to the permit review, or the mass application of specific types of controls to specific types of sources. The R scripts used the same information that CoST would have used (emissions inventories and the control measures database) but we were able to more finely tune the analysis to update inventory information and apply the specific controls assumed by those with industry sector expertise.

<sup>226</sup> The workbook is available here: <https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6>.

<sup>227</sup> The Final Non-EGU Sectors TSD is available in the docket.

<sup>228</sup> R is a free software environment for statistical computing and graphics. Additional information is available here: <https://www.r-project.org/>.

<sup>229</sup> 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>.

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.

Commented [EPA142]: Updated per comment above.

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 covered in the final rule. 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. The EPA notes that the \$7,500 cost/ton threshold reflected in the analytical framework in the non-EGU screening assessment prepared to help shape the proposed FIP was a relative cost/ton level, not a maximum cost threshold. That value was used to identify potentially cost-effective controls for further evaluation. Given the scope of the proposal, the EPA acknowledges that it did not prepare detailed engineering analyses for the

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Commented [EPA144R143]: Edit accepted

~~industries and individual emissions units identified as proxies in the non-EGU screening assessment and shown in the proxy non-EGU screening assessment results for 2026. However, we believe the non-EGU assessment provides a sufficient basis for identifying impactful industries and estimating representative NO<sub>x</sub> emissions reductions and costs to inform the Step 3 analysis for this rule. We provide a more detailed explanation of our analytical framework for assessing potential controls for industrial sources and associated downwind air quality improvements in Section V.D of this notice.~~

### 3. Other Stationary Sources NO<sub>x</sub> Mitigation Strategies

As part of its analysis for this final rule, the EPA also reviewed whether NO<sub>x</sub> 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.

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<sub>x</sub> Mitigation Strategies Final TSD and in the *RTC* Document.

*a. Municipal Solid Waste Units*

At proposal, the EPA solicited comments on whether NO<sub>x</sub> 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<sub>x</sub> emissions and that significant annual NO<sub>x</sub> 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<sub>x</sub> that contribute to ozone problems in the states covered by the proposal. Multiple commenters

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referenced the OTC MWC report to contend that NO<sub>x</sub> 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 for the proposed rule, 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> limits in a FIP is not necessary to continue to reduce NO<sub>x</sub> 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<sub>x</sub> emissions limits that are below the current federal NSPS NO<sub>x</sub> emissions limits for MWCs under 40 CFR 60 subparts Cb and Eb. One commenter noted that MWCs do not always account for a large percentage of statewide NO<sub>x</sub> emissions. Others suggested that voluntary industry actions are also driving downward trends of NO<sub>x</sub> 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<sub>x</sub> emissions limits, the EPA acknowledges that some states included in this rulemaking have promulgated RACT NO<sub>x</sub> emissions limits that apply to certain MWCs, including some that are lower than current MWC NSPS NO<sub>x</sub> 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

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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 notice 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<sub>x</sub> 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<sub>x</sub> emissions limits for MWCs can be achieved at a reasonable cost, as described in Section VI.C.6 of this notice, 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 notice 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<sub>2</sub>, CO<sub>2</sub> and NO<sub>x</sub> emissions. *See* 63 FR 57484. The NO<sub>x</sub> 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<sub>x</sub> 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.<sup>230</sup> 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<sub>x</sub> Ozone Season Group 3 Trading Program would be subject to the emissions reduction requirements established in this

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<sup>230</sup> Preliminary estimate based on representative coal units with starting NO<sub>x</sub> rate of 0.2 lb/mmBtu, 10,000 BTU/kwh, and assuming 80 percent reduction.

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rulemaking for EGUs. However, those applicability criteria—which the EPA is not altering in this rulemaking (*see* Section VI.B.3 of this notice)—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<sub>x</sub> 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”<sup>231</sup>, 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<sub>x</sub> emissions from rich burn reciprocating engine, gas turbine, and microturbine systems are low, ranging from 0.013 to 0.05 lb/mmBtu. NO<sub>x</sub> emissions from lean burn reciprocating engine systems and gas-powered steam turbines systems range from 0.1 to 0.2

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<sup>231</sup> This document is available at: [https://www.epa.gov/sites/default/files/2015-07/documents/catalog\\_of\\_chp\\_technologies.pdf](https://www.epa.gov/sites/default/files/2015-07/documents/catalog_of_chp_technologies.pdf).

lb/mmBtu. The highest NO<sub>x</sub> emitting CHP units are solid fuel-fired boiler/steam turbine systems which emit NO<sub>x</sub> 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<sub>x</sub> 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 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

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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 notice that serve electricity generators and that qualify for an exemption from inclusion in the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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.

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These emissions limits are set forth in Section VI.C.5 of this notice. 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 notice.

#### 4. Mobile Source NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions from onroad and nonroad mobile sources have substantially decreased (73 percent and



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57 percent since 2002, for onroad and nonroad, respectively)<sup>232</sup> 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.<sup>233</sup>

For example, in 2014, the EPA promulgated new, more stringent emissions and fuel standards for light-duty passenger cars and trucks.<sup>234</sup> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> and will be one of the largest mobile source contributors to ozone in

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<sup>232</sup> US EPA. Our Nation's Air: Status and Trends Through 2019.  
[https://gispub.epa.gov/air/trendsreport/2020/#home\\_](https://gispub.epa.gov/air/trendsreport/2020/#home_)

<sup>233</sup> National Emissions Inventory Collaborative (2019). 2016v1 Emissions Modeling Platform. Retrieved from [http://views.cira.colostate.edu/wiki/wiki/10202\\_](http://views.cira.colostate.edu/wiki/wiki/10202_)

<sup>234</sup> Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emissions and Fuel Standards, 79 FR 23414 (April 28, 2014).

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2025.<sup>235</sup> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 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

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<sup>235</sup> 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>.

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evaluate the contribution of states to ozone air quality problems in other states. See Section IV.C of this notice.

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<sub>x</sub> 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.<sup>236</sup> 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

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<sup>236</sup> 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.

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 notice, the multi-factor test considers increasing levels of uniform control stringency in combination with considering total NO<sub>x</sub> reduction potential and corresponding air quality improvements. The EPA evaluated EGU NO<sub>x</sub> emissions controls that are widely available (described previously in Section V.B.1 of this notice), 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.<sup>237</sup> 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 ~~232~~ 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)

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<sup>237</sup> The only coal-fired power plant in California is the 63 MW Argus Cogeneration facility in Trona, California.

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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 2026 OS NOx	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
<b>Total</b>	<b>196,225</b>	<b>12,680</b>	<b>15,346</b>	<b>16,480</b>	<b>75,067</b>
State	Baseline 2023 OS NOx	Reduction potential (tons) for varying levels of technology inclusion			

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		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
Wisconsin	6,321	7	7	26
<b>Total</b>	<b>222,184</b>	<b>12,854</b>	<b>15,681</b>	<b>16,832</b>

\*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 notice 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 NOx	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

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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	15,886
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
<b>Total</b>	<b>196,225</b>	<b>12,680</b>	<b>15,346</b>	<b>16,479</b>	<b>74,973</b>

\*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 notice 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<sub>x</sub> 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 <sup>TM</sup> and SNCR	38,949,560	2,071
		Totals	571,676,839	44,616

**Commented [EO 12866145]:** P.291, 294, 312, passim. In several instances the rule states, "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." (see pp. 291, 294, 312) Why is this? It would be helpful to provide additional explanation for why emissions limits may differ.

**Commented [EPA146R145]:** Please confirm if the request is to add in the text below.

For example, some emissions units we estimate will be subject to the final rule might already have potential-to-emit (PTE) restrictions that were not reflected in the data the EPA used in their analyses, or some natural gas transportation companies may choose to install controls on specific units using emissions averaging plans and those units could be different than those we estimated would install controls. In addition, some of the emissions reductions estimated in the EPA analysis reflect an assumed control efficiency/percent reduction associated with the actual emissions (e.g., 50% for SNCR installation) when the true emissions reductions at a unit/source could differ (e.g., SNCR could achieve as high as a 70% reduction from current, actual emissions). Finally, the costs in the EPA's analysis are estimates, and the aggregate of varying source-specific conditions could result in lower or higher total costs.



**Table V.C.2-2: Estimated Emissions Reductions (ozone season tons) by Upwind State in 2026**

State	2019 OS Emissions*	OS NOx 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 <sup>238</sup>	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

<sup>238</sup> 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.

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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
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 <sup>TM</sup> and SNCR <sup>a</sup>	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 NOx 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 NOx 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.<sup>239</sup> 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 notice, 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

<sup>239</sup> The non-EGU screening assessment memorandum is available in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150>.

**Commented [EO 12866147]:** In its response to the comment, EPA could do a better job of explicitly addressing why \$7,500 per ton is the correct figure, in contrast to the \$2,000 per ton figure used in the past (assuming that the commenter is correct about this).

**Commented [EPA148R147]:** Explanation added.

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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.<sup>240</sup> 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

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<sup>240</sup> 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 at 48210.

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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<sub>x</sub> Emissions, October 17, 2012), rules in approved SIP submittals, consent decrees, and permit limits.<sup>241</sup>

#### *D. Assessing Cost, EGU and Non-EGU NO<sub>x</sub> 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<sub>x</sub> 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 notice 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 ~~benefits we find~~ 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

<sup>241</sup> 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>.

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<sub>x</sub> 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

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selected. However, if EPA were to go beyond the selected control stringency through inclusion of additional EGU or non-EGU NO<sub>x</sub> 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 ~~other-all~~ receptors show ~~some~~ 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

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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 notice.

#### 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 notice) 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<sub>x</sub> combustion controls, which are widely available at a representative ~~marginal~~ 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



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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 notice, 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

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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.<sup>242</sup>

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.

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<sup>242</sup> 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.

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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.<sup>243</sup> Table V.D.1-2 summarizes the results

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<sup>243</sup> 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

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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.

**Table V.D.1-1: Air Quality at the Receptors in 2023 from EGU Emissions Control Technologies <sup>a</sup>**

Monitor ID #	State	County	Baseline (Engineering Analysis)	SCR/SNCR Optimization + LNB Upgrade	Baseline (Engineering Analysis)	SCR/SNCR Optimization + LNB Upgrade
			Average DV (ppb)		Max DV (ppb)	
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 <sup>b</sup>	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

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 notice.

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			Baseline (Engineering Analysis)	SCR/SNCR Optimization + LNB Upgrade	Baseline (Engineering Analysis)	SCR/SNCR Optimization + LNB Upgrade
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
<b>Average AQ Change Relative to Base (ppb)</b>						0.06
<b>Total PPB Change Across All Receptors Relative to Base<sup>c</sup></b>						1.58

**Table Notes:**

<sup>a</sup> 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.

<sup>b</sup> 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

<sup>c</sup> 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 notice provides a more complete picture of the air quality impacts of the final rule.

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**Table V.D.1-2: Air Quality at Receptors in 2026 from EGU Emissions Control Technologies**

Monitor ID #	State	County	Baseline (Engineering Analysis)	SCR/SNCR Optimization + LNB Upgrade + SCR/SNCR Retrofit	Baseline (Engineering Analysis)	SCR/SNCR Optimization + LNB Upgrade + SCR/SNCR Retrofit
			Average DV (ppb)	Max DV (ppb)	Average DV (ppb)	Max DV (ppb)
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
<b>Average AQ Change Relative to Base (ppb)</b>						0.47
<b>Total PPB Change Across All Receptors Relative to Base (ppb)</b>						7.04

**Commented [EO 12866149]:** Is this table missing some receptors?

**Commented [EPA150R149]:** The table is correct – there is no data for Eddy and Lea, NM monitors. See Table Notes above for Table V.D.1-1.

Figures 1 and 2 to Section V.D.1 of this notice, 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 notice reflects emissions reductions commensurate with optimization of existing SNCRs and SCRs. Figure 2 to Section V.D.1 of this notice 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 notice. 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<sub>x</sub> control technologies. While all major technology breakpoints identified in Sections V.B and V.C of this notice 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<sub>x</sub> standard based on the use of SCR. The NO<sub>x</sub> 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.<sup>244</sup> 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.<sup>245</sup>

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<sub>x</sub> 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<sub>x</sub> have resulted in remaining

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<sup>244</sup> 63 FR 57448.

<sup>245</sup> 71 FR 25345.



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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.<sup>246</sup> The Maryland Code of Regulations requires coal-fired sources to operate existing SCR controls or install SCR controls by specified dates.<sup>247</sup> 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.<sup>248</sup> 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.<sup>249</sup>

As shown in Figure 1 to Section V.D.1 of this notice,<sup>250</sup> 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<sub>x</sub> reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO<sub>x</sub> reductions for each of the near-term emissions control technologies are available at

<sup>246</sup> EPA-HQ-OAR-2020-0272. Comment letter from Attorneys General of NY, NJ, CT, DE, MA

<sup>247</sup> COMAR 26.11.38 (control of NO<sub>x</sub> Emissions from Coal-Fired Electric Generating Units)

<sup>248</sup> <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>

<sup>249</sup> 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>

<sup>250</sup> Included in [Appendix I of the Appendix IG of the](#) Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

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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 notice<sup>251</sup> 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:

- 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<sub>x</sub> 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

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<sup>251</sup> Included in Appendix HG of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

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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<sub>x</sub> reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO<sub>x</sub> 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<sub>x</sub> 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 notice<sup>252</sup> 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

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<sup>252</sup> Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

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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<sub>x</sub> per ozone season.

As noted previously in Section V.B of this notice and in the EGU NO<sub>x</sub> 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.<sup>253</sup>

## 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<sub>x</sub> 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

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<sup>253</sup> This is not to discount the potential effectiveness of these or other NO<sub>x</sub> 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).

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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 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.<sup>254</sup> 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

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<sup>254</sup> 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.

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SCR retrofit costs for units for which the 90<sup>th</sup> percentile cost-per-ton is roughly \$21,000. See Section V.B.a of this notice. 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 notice. [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.](#) ~~However, for some unit types at individual facilities, such as a few boilers that may need to replace an existing control, the estimated average costs may be higher than \$14,595/ton.~~



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 costs for EGUs to retrofit SCR is \$11,000/ton. ~~This reflects a range of cost estimates, with \$20,900/ton for certain units reflecting the 90th percentile of units and can well exceed that for individual EGUs above the 90th percentile~~ (see Section V.B.a of this notice). 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 ~~necessary-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 ~~between boilers and/or engines~~, either between units within the same facility or between units at different facilities. First, if some units boilers and/or engines were exempted from control requirements because of historically low actual emissions, there is a

**Commented [EO 12866151]:** EPA should do more to explain both why these values and why the EGU values are the “cost-effective” ones, rather than more stringent levels.

**Commented [EPA152R151]:** EGU cost-effectiveness is addressed in Sections V.B.1 and C.1. These points observe there is a commensurate relationship between the highest costs individual EGUs may face and the highest costs individual non-EGUs may face.

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 contribution. Finally, as~~ ~~Second, if some owners or operators were able to avoid the control requirements of the final rule because current actual emissions are below the applicability thresholds, those owners or operators could gain a competitive advantage if production shifted from units at another facility subject to the control requirements to the boilers and/or engines that avoided control requirements, potentially resulting in emissions increases. 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 at 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.<sup>255</sup>

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

<sup>255</sup> 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 notice.

**Commented [EPA153]:** Rewritten per interagency reviewer suggestion

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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 notice present a comprehensive solution to eliminating significant contribution for the covered states. The

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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 #	State	County	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
			Average DV (ppb)		Max DV (ppb)	
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	0.00	0.00	0.00	0.00
350250008	New Mexico	Lea	0.00	0.00	0.00	0.00
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
<b>Average AQ Change Relative to Base (ppb)</b>						0.66
<b>Total PPB Change Across All Receptors Relative to Base (ppb)</b>						9.87

**Commented [EO 12866154]:** Why are these zeroed out?  
**Commented [EPA155R154]:** Added Table Notes. 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.

**Table Notes:**  
<sup>a</sup> The EPA notes that the design values reflected in Table V.D.2-2 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.  
<sup>b</sup> 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.  
<sup>c</sup> 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 notice provides a more complete picture of the air quality impacts of the final rule.

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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 ~~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 notice 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** <sup>a, b, c</sup>

Sector/Technology	Ozone Season Emissions Reductions	Total PPB Change Across All Downwind Receptors <sup>d</sup>	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 notice.

<sup>b</sup> 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 notice, 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).

<sup>c</sup> 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.

<sup>d</sup> 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 notice 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



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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.*<sup>256</sup>

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.

<sup>256</sup> Although the Court described over-control as going beyond what is needed to address “nonattainment” problems, the EPA interprets this 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.

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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. Similar to our approach in the CSAPR Update and the Revised CSAPR Update, we primarily analyze overcontrol using a configuration in which only the effects of the emissions reductions of the upwind states found linked to a receptor affect that receptor, and we 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 gain the benefit of incidental effects on air quality resulting from reductions in emissions in non-linked states, and downwind states in which a receptor is located are held to a “fair share” of emissions reductions that the upwind states must implement. The EPA also included an alternative configuration, as described in the Ozone Policy Analysis Final Rule TSD. In this configuration, we looked at the combined effect of the entire program across

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~~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.~~  
~~We also looked at the ordering of increments of emissions reduction and have determined it makes the most sense to assume EGU emissions controls would be applied first, followed by non-EGU controls. For 2023, the question is moot as there are only EGU reductions~~

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~~to examine. In 2026, EPA examined all EGU reductions first and layered in non-EGU reductions in the last step of the overcontrol check. 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 TSD for details). Although the ordering ultimately did not impact the results of the overcontrol test, EPA determined it was appropriate to evaluate EGU reductions first as those reductions are grouped into a single trading program whose implementation will begin at an earlier date.~~

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.<sup>257</sup> 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

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<sup>257</sup> 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.

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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 notice, with respect to EGUs, the EPA extends ~~compliance flexibility by phasing in~~ the full implementation of the SCR retrofit-based reductions across 2026 and 2027 to accommodate any *unit-level* scheduling challenges. However, we ~~generally~~ 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 notice. 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

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sources to ~~take~~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.<sup>258</sup> By 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

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<sup>258</sup> 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 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.

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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.<sup>259</sup>

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

<sup>259</sup> 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.

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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<sub>x</sub> 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 notice 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



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~~ozone may also be impacted by factors in future years that the EPA cannot fully account for at ~~in~~  
~~the~~ 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.~~

~~Based on the current record, the EPA cannot conclude that any aspect of its selected Step  
3 level of control stringency constitutes unnecessary over control for any of the 23 states found  
to be linked in 2023 or any of the 20 states found to be linked through 2026. The final  
determination that the stringency of this action does not constitute overcontrol for any linked  
state is further reinforced by EPA’s observation in Section IV.A.1 of this notice regarding the  
nature of the ozone problem. Ozone levels are known to vary, at times dramatically, from year to  
year. Many factors contribute to high ozone levels, with anthropogenic emissions representing~~

~~only one of many contributing causes. Future ozone concentrations and the formation of ground level ozone may be impacted by a variety of factors in future years that the EPA cannot account for in its present modeling or project with certainty. Factors that could contribute to higher than anticipated ozone levels in future years include: climate change (including wildfires and heat waves, which can contribute directly and indirectly to higher levels of ozone), changes in international emissions, changes in anthropogenic emissions in the U.S. that could result from currently unknown economic factors, and changes in other regulatory requirements that may affect emissions of ozone precursors.~~

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<sub>x</sub> emissions during the ozone season.<sup>260</sup> We have 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

<sup>260</sup> As discussed in Section IV.C.2.b, there are also potentially ways in which the IRA may not necessarily result in reductions in NO<sub>x</sub> emissions from EGUs.

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

**Commented [EO 12866156]:** If EPA’s analysis doesn’t explore the effects of IRA implementation on benefits, please discuss and generally summarize expected effects

**Commented [EPA157R156]:** See previous responses about IRA impacts in RIA.

**Commented [Round 2158R156]:** 3/9/2023: We are requesting that EPA provide some language in the preamble to directly address this topic, even if general

**Commented [EPA159R156]:** Per the 3/10 teleconference, we added language to clarify.

**Commented [EO 12866160]:** Reductions? Limits?

**Commented [EPA161R160]:** Added “reductions”

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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.<sup>261</sup> If the EPA were to select the control stringency of this

<sup>261</sup>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.

~~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. As explained earlier in this section, this in fact is the case with the final rule air quality modeling, which shows that the receptors to which these states were linked did not resolve upon full implementation of the identified EGU reductions by themselves, and only reached attainment by a small degree following the additional reductions from the non-EGU control strategies.<sup>262</sup>~~

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

<sup>262</sup>~~Because we did not identify cost, air quality, and emission reduction factors that differentiated 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, the inherent uncertainty in projecting future ozone levels, 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.~~

**Commented [EPA162]:** Added per interagency reviewer suggestion.

contribution.

*Response:* This final rule’s determination regarding the appropriate level of control stringency for EGUs finds that the amounts of NO<sub>x</sub> emissions reduction achieved through these strategies at EGUs are appropriate and cost-justified under the Step 3 multifactor analysis ~~for as long as the strategies remain available to the sources. 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. EPA’s Step 3 finding is not limited to a determination of the mass-based reduction in emissions that the EPA determines is achievable for the covered EGU fleet under current operating conditions. Rather, the EPA finds at Step 3 that to eliminate significant contribution, EGUs must continue to achieve NO<sub>x</sub> emissions performance in the ozone season commensurate with the level of emissions control stringency the EPA finds under the multifactor test as set forth in this section. As discussed in Section VI.B of this notice, the computation of both preset and dynamic emissions budgets simply reflect the stringency of the emissions control strategies as applied to the affected EGU fleet using the latest data reported by those sources. Dynamic budgets facilitate the successful application of this final rule’s control stringency more~~

Commented [Round 2163]: 3/9/2023: unfinished sentence

Commented [EPA164R163]: Edited. Thanks for catching this!

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~~consistently over time than EPA’s approach in the Revised CSAPR Update of computing preset emissions budgets for a set number of control periods or the EPA’s approach before that of computing a fixed, mass-based budget for all future control periods at the time of the rulemaking. This retention of a constant degree of stringency over time by customizing emissions budgets to a changing fleet would not constitute over-control any more than the permanent imposition of emissions rate standards on individual sources at the time of the rulemaking would constitute over-control.~~

~~Further,~~ 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 ~~prohibited~~ overcontrol are persuasive.

~~The dynamic budgets simply establish a stringency reflective of the emissions control performance EPA has determined is necessary to eliminate significant contribution under the Step 3 multifactor analysis (discussed in Section V of this notice). EPA has adjusted the role of dynamic budgeting in this final rule as compared to the proposal. See Section VI.B.1.b.i of this notice. In particular, through 2029, EPA has established pre-set budgets based on known changes in the EGU fleet, and dynamic budgets would only be imposed in those control periods if future reported heat input levels happen to exceed what EPA currently assumes for heat input levels based on older reported data, which in turn would yield *higher* dynamic budgets compared to preset budgets for these control periods. Only for the 2030 ozone season control period and beyond is EPA relying on dynamic budgets with no preset budget serving as a floor. As explained in Section VI.B.1.b.i of this notice, this innovation ensures that the budgets continue to reflect the actual state of the industry (e.g., capturing turn-over in the fleet of EGUs) and thus~~

~~avoid diluting emissions control performance that EPA has determined is reasonable and therefore required at Step 3.~~

~~Similarly, as explained in Section VI.B.1.b of this notice, the annual bank recalibration, the backstop daily emissions rate, and the secondary emissions limitation are also enhancements to the trading program that ensure that each EGU remains incentivized to continuously achieve the level of emissions performance found appropriate at Step 3 to eliminate significant contribution. In response to commenter feedback, EPA has made some changes in these enhancements in the final rule from proposal, and these are discussed in Section VI.B of this notice.~~

~~EPA does not agree that these enhancements, as finalized, result in overcontrol. First, as discussed earlier in this section, EPA has assessed the stringency of the final rule in multiple ways to determine whether actual, prohibited overcontrol exists in 2023 and 2026 and has found that this is not the case. Specifically, EPA found that none of the covered states' linkages to all receptors would resolve at a less stringent control strategy than the one finalized in the final rule.~~

~~Commenters contend that these enhancements to the trading program go 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.~~



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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).

Commenters contend, however, that these enhancements to the trading program go 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 EPA found appropriate at Step 3, regardless of whether other emissions reductions might offset deteriorating emissions control performance, commenters believe these enhancements must necessarily result in prohibited overcontrol.

This is an incorrect understanding of EPA's prior rulemakings, the design of the statute, and prior caselaw on overcontrol. As an initial matter, no commenter has provided an empirical analysis demonstrating that EPA's emissions control strategy will actually result in any

~~overecontrol, and this should be an end of the matter, since over-control allegations must be proven through particularized, as-applied challenges. See prior response to comments.~~

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 ~~in light of~~ ~~the~~ 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 notice, 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.~~As explained in Sections III.B.1.d and VI.B.1 of this notice, EPA finds good reason based on its experience with trading programs that using fixed mass-based budgets does not necessarily ensure the elimination of significant contribution in perpetuity. As noted there, even in the original CSAPR rulemaking, which promulgated only fixed mass-based budgets, such behaviors were never EPA’s intention to allow. See, e.g., 76 FR at 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

**Commented [EO 12866165]:** At pp. 333-334, the draft states that EPA is basing the need for enhancements on its experience implementing the program, but the discussion speaks in general terms until the bottom of p. 334, where EPA cites one example of a source idling controls around high exceedance days. It would be helpful to discuss in greater detail the evidence EPA considered related to its historic implementation experience.

**Commented [EPA166R165]:** Additional detail added in Section III.B per commenter suggestion.

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contribution).”). ~~Thus, d~~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 Further, 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. EPA now believes it is appropriate to ensure in a more comprehensive manner, and in perpetuity, that the mass-based emissions budget ~~trading program~~ 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 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 notice.

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The EPA also explained this in the proposal. See 87 FR at 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 ~~could hardly be considered~~ 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. ~~The example of the Miami Fort Unit 7, located in Ohio, discussed in the Final Rule TSD illustrates this point. This unit (possessing SCR control technology) more than tripled its ozone-season NO<sub>x</sub> emissions rate between 2017 and 2019 to levels indicating non-operation of~~

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~~the control. This occurred during a period in which receptors to which the state was found linked continued to experience monitored exceedances of the 2008 ozone NAAQS. See Section V.B.1.a and VI.B.~~ of this notice 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 ~~generally~~ 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 (9<sup>th</sup> 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. The EPA’s 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).~~ ~~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 ~~continuous~~ 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

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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.<sup>263</sup>

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 notice.

~~EPA has assessed overcontrol in the analytic year relevant to the onset of emissions control stringency associated with retrofitting SCRs (i.e., in 2026). EPA has no particularized evidence that this stringency will result in overcontrol in any year beyond 2026.~~

<sup>263</sup>

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.

**Commented [EPA167]:** Added per interagency reviewer suggestion.

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<sub>x</sub>, 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).~~<sup>264</sup> ~~This is in fact But this too was hardly a holding that EPA may not implement an emissions control strategy at Step 4 of the good neighbor framework that ensures continuous, permanent achievement of emissions control strategies that EPA has found warranted at Step 3. As we have explained elsewhere, nothing in the CAA would prevent the Agency from implementing good neighbor obligations through the imposition of unit specific emissions limitations that would apply in perpetuity. See CAA sections 110(a)(2) and 302(y) (providing for SIPs and FIPs to include "enforceable emissions limitations" in~~

<sup>264</sup> "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. . . ."



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~~addition to economic incentive measures like trading programs).<sup>265</sup> And this is effectively the same result that these trading program enhancements seek to achieve. Further, this is precisely~~  
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 notice). 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 notice.

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 notice.~~However, the particularized circumstances under which any such revision to a FIP or approval of a SIP could be acceptable are not presently known or properly before the Agency on the record for this action.~~

Therefore, commenters' contentions that EPA's trading program enhancements result in prohibited 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

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<sup>265</sup> ~~"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...."~~

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<sub>x</sub> 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.~~ This action will ensure that emissions reductions necessary to eliminate significant contribution will be achieved as “as expeditiously as practicable” as required under CAA section 181(a). 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 notice, 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.<sup>266</sup> 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<sub>2.5</sub>.<sup>267</sup> 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.<sup>268</sup> 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.<sup>269</sup> The Court noted in *Wisconsin* that the statutory command—that compliance with the

<sup>266</sup> *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).

<sup>267</sup> *North Carolina*, 531 F.3d at 911-913.

<sup>268</sup> *Wisconsin*, 938 F. 3d at 303, 3018-20.

<sup>269</sup> *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

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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.”<sup>270</sup>

#### 1. 2023-2025: EGU NO<sub>x</sub> 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 notice are not yet available. The EGU NO<sub>x</sub> 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 notice 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

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deadline for attaining the 2008 ozone NAAQS. 964 F.3d at 1226 (citing *Wisconsin* and *Maryland*).

<sup>270</sup> *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).

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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 notice, 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 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).<sup>271</sup> ~~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). The EPA is applying the same timing assumption regarding combustion control upgrades for this proposed rulemaking the expected similar final action date and the start of the year one ozone season EPA is not assuming the implementation of any additional combustion control upgrades in state emissions budgets until~~ 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<sub>x</sub> Reductions Beginning in 2026

The EPA finds that it is not possible to ~~require implementation of~~ 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

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<sup>271</sup> 86 FR 23093.

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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.<sup>272</sup> 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 notice. 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 notice](#). 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 notice. 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](#) ~~substantial enough that we have~~ 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

<sup>272</sup> 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).

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.<sup>273</sup>

~~The EPA finds that compliance schedule is the most expeditious practicable; it delivers substantial emissions reductions in the 2026 and 2027 ozone seasons and before the 2027 Serious area attainment date, and it allows a small remainder of the required emissions reductions to be implemented no later than the~~The timing of this final rule ~~provides~~ provides more than 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<sub>x</sub> 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

<sup>273</sup> 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.



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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.<sup>274</sup> 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 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, necessity. Our analysis based on comments and considering additional information is that the additional time we have provided in

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<sup>274</sup> CAA 110(a)(2)(D)(i) and 126(c).

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.<sup>275</sup> Specifically, for these areas, CAA sections 182(b)(2) and 182(f) require that states implement RACT for existing VOC and NO<sub>x</sub> 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.<sup>276</sup> 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.<sup>277</sup>

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<sup>275</sup> 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).

<sup>276</sup> 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 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.

<sup>277</sup> 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation).

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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.<sup>278</sup> 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

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<sup>278</sup> 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.

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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<sub>x</sub> in downwind Moderate nonattainment areas and some upwind areas, which many states have already implemented in their SIPs.<sup>279</sup> 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) ~~generally~~ authorizes the EPA to grant an extension

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<sup>279</sup> *See* the [Final](#) Non-EGU Sectors TSD for a discussion of SIP-approved RACT rules in effect in downwind states.

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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.<sup>280</sup> 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 notice, 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 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,<sup>281</sup> the

<sup>280</sup> See, e.g., CAA section 112(i)(4), which provides for limited compliance extensions granted by the President based on national security interests.

<sup>281</sup> 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).

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~~implementation of good neighbor obligations for these NAAQS is already delayed, and the sources subject to NO<sub>x</sub> 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~~ the upwind states in this action are substantially delayed in the ~~implementation of good neighbor obligations for these NAAQS is already delayed, and the sources subject to NO<sub>x</sub> 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 more than~~ 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 notice 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). ~~May 1, 2027, is more than four years after the date by which the EPA currently anticipates promulgating a final FIP for the covered states, more than four years after the January 1, 2023, deadline for implementation of section 182 RACT SIP provisions in areas classified as Moderate or higher, and seven years after the 2020 ozone season, which was the last full ozone season before the 2021 Marginal area attainment date.~~

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

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before EPA’s statutory deadline under CAA section 110(c) to promulgate a FIP.<sup>282</sup> 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.”<sup>283</sup>

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),<sup>284</sup> 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, the broad scope of this rule coupled with current information on the present economic capacity of sources, control installation vendors, and associated markets for labor and indicates that a three-year timeframe is not possible for all sources subject to this rule collectivelyTherefore, for reasons of necessity, additional time beyond 2026 will be allowed for

<sup>282</sup> 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.

<sup>283</sup> *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”).

<sup>284</sup> Compliance by the August 3, 2021, Marginal area attainment date is also impossible as that date has passed.

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 notice, 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<sub>x</sub> 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<sup>285</sup>), nearly 19 GW of SCR retrofit came online in 2002 and another 42 GW of SCR retrofit came

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<sup>285</sup> See 63 FR 57356 (October 27, 1998); 65 FR 2674 (January 18, 2000). The D.C. Circuit stayed the NO<sub>x</sub> 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.



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 NOx budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NOx 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 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.<sup>286</sup> 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

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<sup>286</sup> 86 FR 23102

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.”).

*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 at 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

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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 notice, 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.-

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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<sub>x</sub> burners, layered combustion, NSCR, SCR, fluid gas recirculation, and SNCR/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.<sup>287</sup> 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

<sup>287</sup> See generally SC&A, *NO<sub>x</sub> Emission Control Technology Installation Timing for Non-EGU Sources* (DATE) (“Non-EGU Control Installation Timing Report”).

~~particular, could take between 9 and 72 months depending on supply chain delays.~~<sup>288</sup> ~~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. 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<sub>x</sub> burners, layered combustion, NSCR, SCR, fluid gas recirculation, and SNCR/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 without any supply chain delays and months with potential supply chain delays depending on the industry.~~<sup>289</sup> ~~The Non-EGU Control Installation Timing Report also identified maximum estimated installation times ranging from 12-9 months without any supply chain delays and 12-112 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 112 months depending on supply chain delays.~~<sup>290</sup> ~~These estimates do not take into account the potential for additional delays related to permitting processes, which the report estimates typically require 6 to 12 months.~~<sup>291</sup>

~~We find that the potential time needed for permitting processes is~~ ~~We find that the potential for additional delays in permitting processes are~~ generally unlikely to significantly

<sup>288</sup> See Non-EGU Control Installation Timing Report, Executive Summary.

<sup>289</sup> See generally SC&A, *NO<sub>x</sub> Emission Control Technology Installation Timing for Non-EGU Sources (DATE)* (“Non-EGU Control Installation Timing Report”).

<sup>290</sup> See Non-EGU Control Installation Timing Report, Executive Summary.

<sup>291</sup> Id. at Section 5.6.

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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. ~~need for additional time beyond 2026 becomes apparent.~~ 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

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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.<sup>292</sup> 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

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<sup>292</sup> Id. at Section 6.1.

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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, 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 notice, 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 notice, 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 notice 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.

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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 at 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).

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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.”<sup>293</sup> 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<sub>x</sub> 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 power sector, EGUs’

<sup>293</sup> *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”).

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.

~~As discussed later, to provide improved environmental outcomes, in this rulemaking, the EPA is making certain enhancements to the current provisions of the Group 3 trading program addressing environmental performance by some kinds of individual units that will necessarily reduce the flexibility of the program to some extent for those units. However, with the enhancements, the inherently greater flexibility of a trading program continues to favor the use of this form of regulation, relative to more prescriptive forms of regulation, as a vehicle for~~

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~~achieving the emissions reductions from the electric power sector found to be necessary in this rulemaking.~~

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<sub>x</sub> 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,<sup>294</sup> and affected EGUs within the borders of the three states not currently covered by any CSAPR trading program for seasonal NO<sub>x</sub> emissions – Minnesota, Nevada, and Utah – will enter the Group 3 trading program in the 2023 control period on the effective date of this rule. As discussed in Section VI.B.12.a of this notice, 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

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<sup>294</sup> 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.



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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 ~~as well as units not located in Indian country~~. Sections VI.B.2 and VI.B.3 of this proposed 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<sub>x</sub> 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

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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<sub>x</sub> trading program.<sup>295</sup>

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 notice. 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

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<sup>295</sup> 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.

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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 notice. 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 notice.

#### 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<sub>2</sub> 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<sub>2</sub> or NO<sub>x</sub> 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.<sup>296</sup> 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 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.

<sup>296</sup> The six current CSAPR trading programs are the CSAPR NO<sub>x</sub> Annual Trading Program, CSAPR NO<sub>x</sub> Ozone Season Group 1 Trading Program, CSAPR SO<sub>2</sub> Group 1 Trading Program, CSAPR SO<sub>2</sub> Group 2 Trading Program, CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, and CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program. The regulations for the six programs are set forth at subparts AAAAAA,BBBBB, CCCCC, DDDDD, EEEEE, and GGGGG, respectively, of 40 CFR part 97.

- “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.<sup>297</sup>

- 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,

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<sup>297</sup> As discussed in Section VI.B.6 of this notice, 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<sub>x</sub> Budget Trading Program in the form of “flow control” provisions.

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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 at 23071, 23083. While this unit-level behavior may have been permissible under the prior program, emissions ~~existing emissions controls. missions~~ 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



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significant contribution.<sup>298</sup>

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 -in order to maintain as much compliance and operational flexibility as possible, while also maintaining appropriate compliance and operational flexibility for EGUs.theimplementing a backstop 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 maintenance on the critically important days, this combination of provisions will ~~require~~ strongly incentivize sources to plan to run controls all season, including

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<sup>298</sup> 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.

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on the highest ozone days, while giving reasonable flexibility for occasional operational needs.<sup>299</sup>

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 proposed 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 notice. The individual revisions are discussed in more detail in Sections VI.B.4 through VI.B.9 of this notice.

*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.

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<sup>299</sup> Deferral of the backstop daily emissions rate for certain EGUs, for reasons discussed in Section VI.B.7 of this notice, 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).

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).<sup>300</sup> 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

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<sup>300</sup> 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).

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exceedance.<sup>301, 302</sup> 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 years through 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.

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<sup>301</sup> 86 FR 23117.

<sup>302</sup> 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<sub>x</sub> 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<sub>x</sub> rate (which tends to be higher than the absolute lowest seasonal average rate).”).

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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 notice and the Ozone Transport Policy Analysis Final Rule TSD. To summarize here, the

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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

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used to determine dynamic state emissions budgets for the 2026 control period.<sup>303</sup> 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

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<sup>303</sup> As discussed in Section VI.B.4 of this notice, 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).



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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 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 notice.

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,<sup>304</sup> 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

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<sup>304</sup> 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 notice 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.

defined as eliminating significant contribution to nonattainment and interference with maintenance.

As discussed in detail in Section VI.B.6 of this proposed 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

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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 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 ~~ensuring that the annual bank recalibration will prevent 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 proposed 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 proposed 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 proposed trading program enhancements intended to improve emissions performance at the level of individual units is the addition of backstop daily NO<sub>x</sub> 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<sub>x</sub> 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

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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.<sup>305</sup> They have noted that while the trading programs established under the NO<sub>x</sub> 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 notice and in the EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD in the docket. [While the EPA has in](#)

<sup>305</sup> E.g., comments of Maryland Department of the Environment on the proposed Revised CSAPR Update at 3, EPA-HQ-OAR-2020-0272-0094.



~~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 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.~~

~~While the EPA has in prior ozone transport actions not found sufficient evidence of emissions control idling or non-operation to take the step of building in enhancements to the trading program to ensure unit level control operation, our review of that information applied to this context suggests this problem could become more prevalent in future years relevant to this action.~~

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

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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).<sup>306</sup>~~level both because it is appropriate and justified in the context of eliminating significant contribution under CAA section 110(a)(2)(D)(i)(I) and because. While the former justification is sufficient to finalize this enhancement to the trading program, and because this measure will deliver public health and environmental benefits to overburdened communities (as well as the rest of the population). While the former justification would be reason enough to finalize this enhancement to the trading program, the EPA sees nothing improper in acknowledging that the measure has complementary environmental justice benefits as well.~~

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,

<sup>306</sup> 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.

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and forego an emissions trading approach altogether. While this is ~~clearly~~ 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<sub>x</sub> 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 notice, 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).<sup>307</sup>

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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

<sup>307</sup> As illustrated in the table and underlying data, a small portion of this ppb impact is attributable to combustion control upgrade potential.

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<sub>x</sub> 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.<sup>308</sup>

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

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<sup>308</sup> EPA-HQ-OAR-2020-0272-0094.

as a common practice for the best control of NO<sub>x</sub> 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<sub>x</sub> emissions 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.

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The EPA developed the level of the daily average NO<sub>x</sub> emissions rate – 0.14 lb/mmBtu – through analysis of historical data, as described in Section VI.B.7 of this notice. A rate of 0.14 lb/mmBtu represents the daily average NO<sub>x</sub> 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<sub>x</sub> emissions by coal-fired units with SCR controls that are achieving a seasonal NO<sub>x</sub> average emissions rate of 0.08 lb/mmBtu (or less), which is the seasonal NO<sub>x</sub> emissions rate that the EPA has determined is indicative of optimized SCR performance by units with existing SCR controls.

~~The unit-specific daily emissions rate provisions will strengthen the incentives for individual coal-fired units with SCR controls to operate and optimize performance of the controls. More continuous operation and optimization of post-combustion controls at individual units will help address individual days that prove in real time to be most critical for downwind ozone levels. Better emissions performance by individual units will also help address disparate impacts of pollution on overburdened communities downwind from the units.~~

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

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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<sub>x</sub> emissions rates separately; otherwise, the daily emissions rate provisions will apply to the SCR-equipped units based on the combined NO<sub>x</sub> 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 <sup>309</sup>

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 –

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<sup>309</sup> 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 notice.

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 notice. 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 notice.

ii. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

The second of the proposed 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. 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<sub>x</sub> emissions during the control period that exceed by more than 50 tons the NO<sub>x</sub> 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<sub>x</sub> 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 ~~principal~~ purpose of the proposed 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. ~~likely will also help address disparate impacts of pollution on overburdened communities downwind from some such units. See Ozone Transport Policy Analysis 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 notice.

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

**Commented [Round 2177]:** 3/9/2023: Reviewing agency suggests that EPA modify the response in Section VI.B.d of the Preamble regarding coordination or in the Reliability Technical Support Document to state that the reliability assessment is a resource adequacy assessment and not a comprehensive reliability assessment. [See accompanying comment in the Reliability Technical Support Document.]

**Commented [EPA178R177]:** We edited the TSD and added a footnote reference in this section of the preamble.

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under this rule through expansion and enhancement of the Group 3 trading program originally established in the Revised CSAPR Update, ~~including 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

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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, and some 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.

Some of the commenters raising concerns about electric system reliability suggested potential modifications to the proposed rule that the commenters believed could help address

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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

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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<sub>x</sub> 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

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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 notice, 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



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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. ~~No EGU is required to retire or is prohibited from operating at any time under this rule, subject to surrender of the appropriate quantity of allowances.~~<sup>310</sup>

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

<sup>310</sup> 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.

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despite CSAPR not being in effect.<sup>311</sup> 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.<sup>312</sup> Through these meetings, the central

<sup>311</sup> For a state-by-state comparison, see Appendix G of the Ozone Transport Policy Analysis Final Rule TSD.

<sup>312</sup> 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.

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<sub>x</sub> 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<sub>x</sub> 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 – 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

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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~~<sup>incentives</sup> 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<sub>x</sub> 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<sub>x</sub> 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

**Commented [EO 12866179]:** If EPA includes a discussion above of DOE’s FPA 202(c) authority as a tool to address unexpected supply/demand imbalances in the unlikely event that they occur, consider including the existence of DOE’s authority as a means to mitigate reliability challenges here as well.

**Commented [EPA180R179]:** In the context of a flexibility trading program, EPA does not view FPA 202(c) authority as needed to ensure the ability of critical resources to operate, because the trading program’s requirements would never prevent them from operating.



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<sub>x</sub> 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

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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<sub>x</sub> 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 notice, 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 electric reliability officials at 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.<sup>313</sup>

<sup>313</sup> 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>.

**Commented [EO 12866181]:** Here, recommend calling back to the description of reliability organizations and their roles in maintaining reliability with the entry and exit of resources in section II.B.1.c on page 89. NERC, FERC, ISO/RTOs and balancing areas already routinely assess reliability inclusive of meeting all regulatory requirements. This could support EPA's position that another recurring modeling of reliability in regards to this rule specifically is duplicative.

**Commented [EPA182R181]:** Thank you for the suggestion – sentence added.

**Commented [EO 12866183]:** DOE does not have "electricity reliability officials." DOE prioritizes reliability across many different offices, from EERE to CESER to OP and others. Recommend EPA correct as listed.  
  
Also, if it is completed ahead of the release of this rule, EPA should add a reference to the EPA-DOE "Joint Memorandum on Interagency Communication and Consultation on Electric Reliability."

**Commented [EPA184R183]:** Text edit accepted. EPA agrees with the recommendation to add a reference to the Joint Memorandum and will do so if timing permits.

**Commented [EPA185R183]:** 2<sup>nd</sup> round – MOU reference added in FN.

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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 of the total quantity of allowances available for compliance in that control period.<sup>314</sup> 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 notice) will total over 30 percent of the full-season emissions budgets.<sup>315</sup> 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

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<sup>314</sup> 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.

<sup>315</sup> 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. See Section VI.B.12.a.](#)

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 ~~and believes that it may be possible to design an auction mechanism in a way that would not dilute the achievement of the emissions reductions required to address states’ good neighbor obligations.~~ 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.<sup>316</sup>

<sup>316</sup> 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.

**Commented [EO 12866186]:** Can you explain why EPA is choosing to defer these potential adjustments?

**Commented [EPA187R186]:** EPA did not propose an auction mechanism and believes the most appropriate way to add such a mechanism to the trading program would be through a supplemental proposal.

## 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<sub>x</sub> 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. As part of the approach for implementing the NO<sub>x</sub> emissions reductions from EGUs identified as necessary to address various states' obligations under the good neighbor provision with respect to the 2015 ozone NAAQS, the EPA is expanding the geographic scope of the existing CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program to encompass the additional states (and Indian country within the borders of such states) found to have such obligations with respect to EGUs.~~

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 notice.

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.<sup>317</sup> In contrast, within the geographic scope of this rulemaking, the EPA is aware of areas

<sup>317</sup> 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

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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 notice. 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 notice.

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 notice, 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<sub>x</sub> 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’

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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.

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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 notice 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 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



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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 ~~the~~ 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 notice, 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 notice, respectively, and MWC applicability criteria are further discussed in Section VI.C.6 of this notice.

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<sub>x</sub> 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 notice. 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.<sup>318</sup> The EPA requested comment on whether each listed unit would or

<sup>318</sup> 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

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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 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.<sup>319</sup> 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).

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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.

<sup>319</sup> 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.

**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		Unit ID	Unit Type	Estimated Ozone Season Heat Input (mmBtu)	Estimated Ozone Season Average NO <sub>x</sub> Emissions Rate (lb/mmBtu)	Notes
	ID	Facility Name					
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:**

<sup>1</sup> 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<sub>x</sub> 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

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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 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

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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 of the notice), 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

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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

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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.<sup>320</sup> 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 x Emissions Rate)/2000	Heat Input (tBtu)	Emissions Rate (lb/mmBtu)	Tons (Heat input x 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
<b>State Budget (tons)</b>			<b>17,000</b>			<b>18,700</b>

**Table VI.B.4-2: Example of Preset and Dynamic Budget Calculation in Scenario of**

<sup>320</sup> See 2021 Form EIA Form 860 – Schedule 3, Generator Data. Department of Energy, Energy Information Administration.

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**Unanticipated Retirement**

	Preset Budget Approach (2028)			Dynamic Budget Approach (2028)		
	Preset Heat Input (tBtu)	Preset Emissions Rate (lb/mmBtu)	Preset Tons (Heat input x Emissions Rate)/2000	Heat Input (tBtu)	Emissions Rate (lb/mmBtu)	Tons (Heat input x 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
<b>State Budget (tons)</b>			<b>17,000</b>			<b>15,000</b>

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 of the notice.

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*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 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<sub>x</sub> 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

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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 notice. 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 unit larger than~~ 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 ~~adjust its historical baseline at Step 1 to account for planned retirements which thus incorporates reflect planned~~ retirements ~~into 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



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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 ~~likely conservative~~ 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

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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.<sup>321,322</sup> 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.<sup>323</sup>

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

<sup>321</sup> Available at <https://www.prnewswire.com/news-releases/energy-harbor-transitions-to-100-carbon-free-energy-infrastructure-company-in-2023-301501879.html>.

<sup>322</sup> 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>.

<sup>323</sup> Available at <https://www.prnewswire.com/news-releases/joppa-power-plant-to-close-in-2022-as-company-transitions-to-a-cleaner-future-301263013.html>.

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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 ~~(as is likely)~~ 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.<sup>324</sup>

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).

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<sup>324</sup> 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.

*Response:* For preset state emissions budget derivation, EPA is finalizing use of the same single-year<sup>325</sup> 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.

~~Moreover, while 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 is able to then~~ further evaluate ~~the use of~~ 2021 historical data ~~emissions and heat input 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

<sup>325</sup> 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.

**Commented [EO 12866188]:** paragraph beginning “Moreover, while recognizing that 2021 is the latest available...”: My understanding of this paragraph is that it says EPA looks at each year’s data and adjusts for anomalies as necessary. Can you add a sentence making that clear?

**Commented [EPA189R188]:** Incorporated edits

screening at the state level by identifying any states where 2021 heat 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).<sup>326, 327</sup> 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<sub>x</sub> 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

<sup>326</sup> 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.

<sup>327</sup> 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~~~~years~~ 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.

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. ~~This~~ 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
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



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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.

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*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.

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*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 notice, 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.

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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.

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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 notice. 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<sub>x</sub> Ozone Season Group 3 Preset State Emissions Budgets for the 2023 through 2029 Control Periods (tons)<sup>a, b</sup>**

<u>State</u>	<u>Final Emissions Budgets for 2023</u>	<u>Final Emissions Budgets for 2024</u>	<u>Final Emissions Budgets for 2025</u>	<u>Preset Emissions Budgets for 2026</u>	<u>Preset Emissions Budgets for 2027</u>	<u>Preset Emissions Budgets for 2028</u>	<u>Preset Emissions Budgets for 2029</u>
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

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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
<b>Total</b>	<b>208,119</b>	<b>198,014</b>	<b>195,259</b>	<b>151,329</b>	<b>119,663</b>	<b>115,193</b>	<b>105,201</b>

State	Final Emissions Budgets for 2023 Control Period (tons)	Final Emissions Budgets for 2024 Control Period (tons)	Final Emissions Budgets for 2025 Control Period (tons)	Preset Emissions Budgets for 2026 Control Period (tons)	Preset Emissions Budgets for 2027 Control Period (tons)	Preset Emissions Budgets for 2028 Control Period (tons)	Preset Emissions Budgets for 2029 Control Period (tons)
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	8,363	8,135	7,280	5,808
Kentucky	13,601	12,999	12,472	9,697	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

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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	31,170	23,127	21,742	20,754
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	150,836	119,781	115,312	105,320

**Table Notes:**

<sup>a</sup> 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.

<sup>b</sup> 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 notice.

**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.<sup>328</sup>

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

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<sup>328</sup> 531 F.3d at 908.

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period plus a variability limit and will continue to apply a 3-for-1 surrender ratio to emissions exceeding the state’s assurance level.<sup>329</sup> 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.<sup>330</sup> 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

<sup>329</sup> 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.

<sup>330</sup> 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.

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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 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

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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.<sup>331</sup> 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

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<sup>331</sup> 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.

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<sub>x</sub> in both CSAPR and the CSAPR Update were set at 21 percent of each state’s budget, and these variability limits for the NO<sub>x</sub> ozone season trading programs were then codified in 40 CFR 97.510 and 40 CFR 97.810,

**Commented [EO 12866190]:** Is there anything else you can say to explain why the analysis supported setting the variability limits at 21 percent?

**Commented [EPA191R190]:** Added a footnote summarizing how the variability limits were determined in the analysis and relocated the citation to a TSD from the original CSAPR rulemaking where the analysis is described in greater detail from the immediately following footnote to that footnote. EPA notes that no public comments were received regarding continued use of 21% as the variability limit.



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along with the respective state budgets.<sup>332</sup> 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.<sup>333</sup> 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.<sup>334</sup> (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

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<sup>332</sup> 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<sub>x</sub> 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.

<sup>333</sup> 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). 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.” Both documents are available in the docket for this rule.

<sup>334</sup> 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.

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 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 notice, 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 notice, is to adopt a

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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

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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.<sup>335</sup> 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 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

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<sup>335</sup> 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.

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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 proposed 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.<sup>336</sup> 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

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<sup>336</sup> See the Power Sector Variability Final Rule TSD from CSAPR, available at <https://www.epa.gov/csapr/power-sector-variability-final-rule-tds> 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.

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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<sub>x</sub> Budget Trading Program established in the NO<sub>x</sub> 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.<sup>337</sup> 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

<sup>337</sup> For more discussion of the progressive flow control mechanism, as well as allowance price data showing a discounted value for banked allowances, see “NO<sub>x</sub> 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>.

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 notice.

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 of 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 notice.

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-

**Commented [EO 12866192]:** “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.” Can you expand this at all? It seems conclusory as written.

**Commented [EPA193R192]:** Expanded slightly here and added cross-reference to longer discussion.



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<sub>x</sub> in accordance with the provisions of the Group 3 trading program.<sup>338</sup> 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.<sup>339</sup> Moreover, as noted earlier in this section, the Group 3 trading program regulations provide the EPA 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,

<sup>338</sup> 40 CFR 97.1006(c)(6)-(7).

<sup>339</sup> 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<sub>x</sub> Budget Trading Program example); 40 CFR 97.106(c)(5)-(6) (CAIR NO<sub>x</sub> Annual Trading Program example).

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<sub>x</sub> 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

**Commented [Round 2194]:** 3/9/2023: If these comments were unpersuasive, it's not clear why EPA is implementing these changes. Suggest that EPA rephrase text to better explain

**Commented [EPA195R194]:** Rephrased preceding sentence and edited text.

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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 notice (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<sub>x</sub> emissions rate of 0.14 lb/mmBtu. The daily average emissions rate provisions will apply to large



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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).<sup>340</sup> All calculations will rely on the data monitored and reported for the unit in accordance with 40 CFR part 75.

The EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD describes the methodology for

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<sup>340</sup> 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.

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.<sup>341</sup> 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<sub>2</sub> attainment area guidance for identifying "comparably stringent" emissions rates

<sup>341</sup> See page 24 of "Guidance for 1-hour SO<sub>2</sub> Nonattainment Area SIP Submission" at [https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance\\_nonattainment\\_sip.pdf](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 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."

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over varying time-periods.<sup>342</sup> 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 99<sup>th</sup> 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 notice, 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<sub>x</sub> 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

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<sup>342</sup> See Guidance for 1-Hour SO<sub>2</sub> Nonattainment Area SIP Submissions available at [https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance\\_nonattainment\\_sip.pdf](https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf).

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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<sub>x</sub> 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<sub>x</sub> 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 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<sub>x</sub> emissions rate provisions, including the reasons for these changes, are discussed in the remainder of this section and in [Section Chapter-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

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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 notice, 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<sub>x</sub> 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<sub>x</sub> 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

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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.1.e of this notice, 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.<sup>343</sup> 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 notice. 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

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<sup>343</sup> 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.



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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 ~~very~~ 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<sub>x</sub> 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. ~~The final rule defers application of the~~

~~provisions to these units until 2030 (unless they install the controls earlier), creating greater flexibility for the sector to develop the most economic alternatives to extensive operation of the units. Again, the EPA sees no reason to speculate that the most economic alternatives would entail shifting generation to resources outside the coverage of the trading program, given that many other compliance strategies will be available.~~

*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 ~~As explained in Section VI.B.7 of this notice, 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<sub>x</sub> emissions rates at or below 0.08 lb/mmBtu, more than 99 percent of the units' emissions would fall below a backstop daily

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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

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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 NOx Mitigation Strategies Final Rule TSD](#)~~Ozone Transport Policy Analysis 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

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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<sub>x</sub> emissions rate, from approximately 0.14 lb/mmBtu to approximately 0.07 lb/mmBtu, and a comparable reduction in NO<sub>x</sub> 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.~~<sup>344</sup> ~~The EPA considers it reasonable to assume that this unit is not uniquely situated, and that other SCR-equipped units that historically have cycled down to low load levels at which the SCR controls cannot be operated 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.~~ 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

<sup>344</sup> See the spreadsheet “Conemaugh and Keystone unit 2021 to 2022 hourly ozone season data” in the docket.

Commented [EPA196]: Edited to address interagency comment.

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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 notice. 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](#)).~~see Section VI.B.7 of this notice for further discussion~~

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 notice, 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. In any event, the equitable interest of the downwind states for the provisions to be implemented as expeditiously as practicable, consistent with the good neighbor provision, is more compelling. In general, we 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 notice, 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 configuration can choose between either upgrading the plant's monitoring systems so as to obtain unit-specific NO<sub>x</sub> emissions rate data for each unit subject to the backstop daily emissions

**Commented [EO 12866197]:** This sentence seemed conclusory to me. Can you explain why it is more compelling?

**Commented [EPA198R197]:** Edited to rely on the statute instead of adding a more extensive downwind equity argument.



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rate or else using the NO<sub>x</sub> 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 ~~the~~ 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.<sup>345</sup>

*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

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<sup>345</sup> 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 notice, EPA staff have reviewed the comment and do not believe the commenter has provided sufficient information to reach such a conclusion.

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 notice, 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 notice. As noted in Section VI.B.1.c of this notice, 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

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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 notice, 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<sub>x</sub> 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~~ ~~unit retirements as a compliance pathway~~. 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<sub>x</sub> 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<sup>346</sup> and the coal combustion residuals rule under the Resource Conservation and Recovery Act.<sup>347</sup> 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.<sup>348</sup> 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<sub>x</sub>

<sup>346</sup> See 40 CFR 423.11(w).

<sup>347</sup> See 40 CFR 257.103(b).

<sup>348</sup> See 40 CFR 51.308(f).

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reduction strategies. To facilitate a unit-level compliance alternative under this rule that maintains the NO<sub>x</sub> 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 notice, 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.<sup>349</sup> Both of the exceedances by Missouri sources could easily have been avoided if the owner and operator of several SCR-equipped, 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<sub>x</sub> 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

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<sup>349</sup> 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).



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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. Because the pollutant involved is ozone season NO<sub>x</sub> 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.<sup>350</sup>

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

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<sup>350</sup> 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 proposing to do 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<sub>x</sub> Annual Trading Program. The EPA expects that reductions in Missouri’s seasonal NO<sub>x</sub> 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<sub>x</sub> emissions.

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<sub>x</sub> 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<sub>x</sub> 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 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<sub>x</sub> emissions rate of 0.10 lb/mmBtu or, if higher, 125 percent times the lowest seasonal average NO<sub>x</sub> emissions rate achieved by the unit in a previous control period when the unit participated in a CSAPR trading program for ozone season NO<sub>x</sub> emissions and operated in at least ten percent of the hours in the control period.<sup>351</sup>

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<sub>x</sub> 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 –

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<sup>351</sup> For the actual regulatory language, see 40 CFR 97.1026(c) as added by this rule.

including the requirement to be equipped with post-combustion controls – exceeded their respective limitations.

**Table VI.B.8-1: Illustrative Results of Applying Proposed Secondary Emissions Limitation in Previous Instances of Assurance Level Exceedances**

Owner / Operator	Unit	125% of lowest previously achieved NO <sub>x</sub> emissions rate (lb/mmBtu)	Actual NO <sub>x</sub> emissions rate (lb/mmBtu)	Secondary emissions limitation (tons)	Actual NO <sub>x</sub> emissions (tons)	Exceedance (tons)
<b>Missouri - 2020</b>						
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
<b>Missouri - 2021</b>						
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 proposed 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 Chapter 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 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<sub>x</sub> emissions could cause a unit to exceed its secondary emissions limitation. Another commenter stated that it is not uncommon for units’ seasonal average NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions rate does not exceed the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest seasonal average NO<sub>x</sub> emissions

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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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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

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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<sup>352</sup> 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.<sup>353</sup>

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.<sup>354</sup>

<sup>352</sup> 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.

<sup>353</sup> 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 notice. 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.

<sup>354</sup> 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”

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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 notice. 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 ~~for New Units~~*

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

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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.

regulations for the Group 3 trading program<sup>355</sup> 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.<sup>356</sup> 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.<sup>357</sup>

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<sup>355</sup> 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.

<sup>356</sup> 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.

<sup>357</sup> 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

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 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 proposal 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<sup>358</sup> 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

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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).

<sup>358</sup> 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.

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 notice). 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 of the notice), 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.<sup>359</sup> 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

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<sup>359</sup> 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.



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.<sup>360</sup> 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.<sup>361</sup> 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. 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

<sup>360</sup> 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.

<sup>361</sup> 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.

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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 of the notice), 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<sub>x</sub> 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

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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 notice 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.<sup>362</sup> 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.

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<sup>362</sup> 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.

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**Table VI.B.9.a-1: Illustrative CSAPR NO<sub>x</sub> 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

**Table VI.B.9.a-2: CSAPR NO<sub>x</sub> 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

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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<sub>x</sub> 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

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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 notice, 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 notice, 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.<sup>363</sup>

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 proposed procedure for determining allocations from each state emissions budget for each control period are described in detail in the Unit-Level Allowance Allocations Proposed 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

<sup>363</sup> 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.

**Commented [EO 12866199]:** P. 509-510: can you explain the sentence that spans 509-10 more thoroughly?

**Commented [EPA200R199]:** Please highlight or provide the beginning words of this sentence; we are unable to identify which sentence this comment refers to based on our current pagination.

**Commented [Round 2201R199]:** 3/9/2023: We assume this comment is now resolved

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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 notice, 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 notice 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

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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<sub>x</sub> 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<sub>x</sub> emissions value over the 5-year period. For coal-fired units of 100 MW or larger, the EPA will further determine a "maximum controlled baseline" NO<sub>x</sub> emissions value, computed as the unit's maximum heat input over the 5-year period times a NO<sub>x</sub> 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

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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<sub>x</sub> mass emissions, in contrast to the 8-year period used in the Revised CSAPR Update for NO<sub>x</sub> mass emissions. Third, the use of the maximum controlled ~~historical~~ 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 ~~historical~~ 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

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total NO<sub>x</sub> value or, if applicable, the unit's maximum controlled ~~historical~~ 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<sub>x</sub> values and also, where applicable, the maximum controlled baseline ~~controlled historical 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 notice) and will communicate the information to the

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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 notice](#)), [while the 2025 allocations will be recorded by July 1, 2024.](#)<sup>364</sup>

~~of this notice). This recordation schedule represents an expected slight acceleration of the recordation schedule in effect immediately before this final rule, which calls for allocations of 2023 and 2024 Group 3 allowances to existing units to be recorded by September 1, 2023.~~<sup>365</sup> 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 those methodologies to the extent possible in developing the allocations of Group 3 allowances for the control periods in 2023 through 2025.

~~As discussed in Section VI.D.1 of this notice, all covered states would also have the option to establish state-determined allowance allocations for the 2024 control period pursuant to the process discussed in that section. A state choosing this option would need to submit a letter of intent to the EPA by the effective date of this rule and would need to submit the SIP revision with the allocations by September 1, 2023. The EPA would defer recordation of the 2024 allowances for the state's sources until March 1, 2024, to provide time for this process to be~~

<sup>364</sup> [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<sub>2</sub> Trading Program \(the “Recordation Rule”\), 87 FR 52473 \(August 26, 2022\).](#)

<sup>365</sup> [The September 1, 2023, recordation deadline was adopted in an earlier final rule in this rulemaking. See Deadlines for Submission and Recordation of Allowance Allocations Under the Cross-State Air Pollution Rule \(CSAPR\) Trading Programs and the Texas SO<sub>2</sub> Trading Program \(the “Recordation Rule”\), 87 FR 52473 \(August 26, 2022\).](#)

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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.<sup>366</sup>

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 [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] 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

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<sup>366</sup> 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.

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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 control period.<sup>367</sup> 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.<sup>368</sup> 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.

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

<sup>367</sup> 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.

<sup>368</sup> 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.



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~~later years. However starting with the 2025 control period, any state wishing to use a procedure different than EPA's default allocations procedure could do so by obtaining approval of a SIP revision, as discussed in Section VI.D of this notice. Where states are making state-determined allocations for control periods in 2025 or later years under approved SIP revisions, the allocations must be submitted to EPA by June 1 of the year before the control period (one month after the EPA would finalize the dynamically determined state emissions budgets for the control period)<sup>369</sup> and the EPA will record the allocations 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 allocations.~~

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.

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~~<sup>369</sup>The current deadlines for states to submit state-determined allowance allocations to the EPA were adopted in the Recordation Rule issued earlier in this rulemaking.~~

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 historical 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.

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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 notice, in the

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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 ~~historical~~ baseline if the unit was eligible to receive an allocation as an existing unit for that control period.<sup>370</sup> This change was made to address the same comments discussed in Section VI.B.9.b of this notice 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

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<sup>370</sup> As discussed in Section X 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.

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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<sub>x</sub> 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<sub>x</sub> 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.<sup>371</sup>

*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

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<sup>371</sup> 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.

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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<sub>x</sub> Ozone Season Group 2 Trading Program (for units in Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin), the CSAPR NO<sub>x</sub> 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 notice, 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.<sup>372</sup> 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 180<sup>th</sup> 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.

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<sup>372</sup> The units are listed in Table VI.B.3-1.



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<sub>x</sub> 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<sub>x</sub> emissions and total daily heat input, daily average NO<sub>x</sub> emissions rate, and daily NO<sub>x</sub> emissions exceeding the backstop daily NO<sub>x</sub> emissions rate. The units will also be required to record and report cumulative NO<sub>x</sub> emissions exceeding the backstop daily NO<sub>x</sub> emissions rate for the ozone season and any portion of such cumulative NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> mass emissions (or unit-level NO<sub>x</sub> emissions rates computed in part based on unit-level reported data on NO<sub>x</sub> 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<sub>x</sub> 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 proposed 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> mass emissions for the SCR-equipped units and correspondingly understate the reported NO<sub>x</sub> mass emissions for the non-SCR-equipped units.<sup>373</sup> As proposed, the 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

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<sup>373</sup> 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.

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<sub>x</sub> 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.

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*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 notice. 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.<sup>374</sup> Thus, while the commenter states that its units do not have straight runs of ductwork ten

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<sup>374</sup> 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.

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.<sup>375</sup>

#### 11. Designated Representative Requirements

As noted in Section VI.B.1.a of this notice, 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

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<sup>375</sup> Appendix A-1 to 40 CFR part 60, Method 1, sec. 11.1.

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

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program.<sup>376</sup> 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<sub>x</sub> 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

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<sup>376</sup>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.



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date.<sup>377</sup> Variability limits, assurance levels, and unit-level allocations for 2023 will all be computed using the appropriately prorated emissions budgets amounts.<sup>378</sup>

As discussed in Section VI.B.2 of this notice, 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

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<sup>377</sup> 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.

<sup>378</sup> 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.

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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 notice.

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

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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, 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 notice.

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

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trading program as of May 1, 2023, regardless of the rule’s effective date, as discussed in Section VI.B.2 of this notice, 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. ~~The reason for requiring sources currently in the Group 2 trading program to participate in the Group 3 trading starting on May 1, 2023 even though the final rule’s effective date is expected to be after May 1, 2023, is that for sources currently in the Group 2 trading~~

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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 at 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<sub>x</sub> 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

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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<sub>x</sub> 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<sub>x</sub> 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

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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<sub>x</sub> 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



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Group 2 allowances will be converted to Group 3 allowances (as was done in the CSAPR Update). The conversion date will be as soon as practicable on or after August 1, 2023, which is 2 months after the compliance deadline for the 2022 control period under the Group 2 trading program and 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.<sup>379</sup> 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

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<sup>379</sup> 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.

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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<sup>380</sup> 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 ~~22,952~~ 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

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<sup>380</sup> 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.

process.<sup>381</sup>

As noted in Section VI.B.12.a of this notice, the EPA expects that the effective date of this rule will occur after 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~~ ~~22,952~~ allowances would be prorated to an initial bank target amount of ~~21,452~~ ~~21,585~~ allowances.<sup>382</sup> 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~~ ~~22,952~~ 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

**Commented [EO 12866202]:** In this rule or elsewhere?

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<sup>381</sup> By comparison, the analogous conversion ratio under the Revised CSAPR Update was 8-to-1.

<sup>382</sup>  ~~$23,094 \times (153 - 10) \div 153 = 21,585$~~ .  ~~$22,952 \times (153 - 10) \div 153 = 21,452$~~ .

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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 notice 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

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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

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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 ~~under this proposed rule~~, the EPA is recalling CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances equivalent in amount and usability to all vintage year 2023-2024 CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> during the control period in one year,” where the relevant limitations include the EPA Administrator’s 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

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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 of the notice. 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



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allowances held in a general account.<sup>383</sup>

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.<sup>384</sup> 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.<sup>385</sup> 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

<sup>383</sup> 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.

<sup>384</sup> The first control period for the Group 2 trading program was in 2017.

<sup>385</sup> 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.

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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 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

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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 1, 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.<sup>386</sup> 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 1, 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 1, 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.<sup>387</sup>

The final revised regulations provide that failure of a source's owners and operators to

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<sup>386</sup> The provision under which the EPA will not deduct Group 2 allowances transferred to unrelated parties before April 1, 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.

<sup>387</sup> 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.

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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 1, 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<sub>x</sub> 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 notice, 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.<sup>388</sup> 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 treated for purposes of the allowance allocation provisions of the regulations for all the CSAPR trading programs.<sup>389</sup>

As discussed in Section VI.B.9.a of this notice, 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

<sup>388</sup> 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.

<sup>389</sup> 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).

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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 notice for the Group 3 trading program, the EPA is ~~revising making revisions to~~ 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 notice. 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 notice 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 Section VI.C.1 through VI.C.6 of this notice.

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 notice, 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



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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<sub>x</sub> 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 notice. 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

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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 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

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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 notice, 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 notice, 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.

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*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<sub>x</sub> 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<sub>x</sub> 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.<sup>390</sup> 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 [ONE YEAR AFTER THE EFFECTIVE DATE OF FINAL RULE], 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

<sup>390</sup> 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).

**Commented [EO 12866204]:** How many requests does EPA anticipate receiving? How much EPA staff time would it take to review a request and develop a case-by-case limit?

**Commented [EPA205R204]:** We are anticipated about 1% of industry (about 35 sources) will attempt to apply for case-by-case limits given the high burden and risk to the source if their application is denied and they have not begun working towards compliance with the final rule. Further, we do not anticipate many sources will request case-by-case limits because all affected units remain subject to the requirements of the final rule unless and until EPA approves a request for a case-by-case limit, and the criteria that must be met for approval of a case-by-case limit will in most cases be difficult to meet. Also, an EPA denial is effective on the date of denial, so a source risks being in violation of the final rule if its application is denied.

We do not have firm estimates on EPA time to review one of these applications but expect industry to spend about 150 hours preparing a case-by-case request and would expect EPA review time to be lower than that estimate.

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 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 notice. For purposes of this

**Commented [EO 12866206]:** What are acceptable methods of stack testing? This seems particularly relevant given how many non-EGUs lack CEMS (as discussed in section above)

**Commented [EPA207R206]:** We have revised the regulatory text in section 52.40(e)(2)(i)(A)(I) to identify the test methods that must be used for this purpose.

**Commented [Round 2208R206]:** 3/9/2023: Can these methods be conducted without CEMS?

**Commented [EPA209R206]:** Yes they can. The stack test methods can be used whether a CEMS is operating or not.

provision, we generally anticipate that costs exceeding the 90th percentile cost estimates in this rule for a given industry may meet this test.

As discussed in Section VI.A of this notice, 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.<sup>391</sup> 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 notice. 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.

<sup>391</sup> *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”).

**Commented [EO 12866210]:** Could this mean in practice that 10% of industrial sources could plausibly meet this threshold?

**Commented [EPA211R210]:** EPA has revised the language to clarify that we would expect costs to be significantly above the highest representative cost identified for any source in the relevant industry. The intent was not to suggest that 10% of sources would meet this threshold.

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*Response:* The 100 tpy PTE threshold and comparable design capacity thresholds of 1000 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. As explained in the proposal, the EPA found 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 1000 ~~horsepower (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



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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](#)~~[Non-EGU Applicability Requirements and Estimate 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 [THE EFFECTIVE DATE OF FINAL RULE] 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

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the EPA by [120 DAYS AFTER THE EFFECTIVE DATE OF FINAL RULE] 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 [THE EFFECTIVE DATE OF FINAL RULE] 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 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<sub>x</sub> 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<sub>x</sub> 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<sup>392</sup> 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

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<sup>392</sup> The ERT website is located at <https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert>.

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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 notice.

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.

**Commented [EO 12866212]:** Can you say more about why you find that that use of a maximum rated capacity of 1,000 hp reasonably approximates the 100 tpy PTE threshold

**Commented [EPA213R212]:** The EPA’s analysis of why 1,000 hp reasonably approximates a 100 tpy PTE threshold can be found in the *Non-EGU Sectors TSD*, at page 4. prepared for the proposed FIP. The TSD for the proposal can be located at <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145>.

*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 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

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**Commented [EO 12866214]:** Can you say more about why engines with a potential to emit of 100 tpy or greater had the most significant potential for NOx emissions reductions?

**Commented [EPA215R214]:** Following the methods in the Non-EGU Screening Assessment, which used emissions units with  $\geq 100$  tpy of actual NOx emissions, the EPA took the same approach with all non-EGU industries and identified control technologies that could potentially be installed on the types of units identified in the Non-EGU Screening Assessment. For engines, these included units with 1000 hp or more with the capability of emitting more than 100 tpy. Consistent with other EPA programs, the EPA set the applicability criteria based on potential to emit or design capacity (where appropriate) to capture these larger emissions units.

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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> annually.

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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<sub>x</sub> 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 notice, 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Emissions Limits for Pipeline Transportation of Natural Gas**

<b>Engine Type and Fuel</b>	<b>Final NO<sub>x</sub> Emissions Limit</b>
Natural Gas Fired Four Stroke Rich Burn	1.0 g/hp-hr
Natural Gas Fired Four Stroke Lean Burn	1.5 g/hp-hr
Natural Gas Fired Two Stroke Lean Burn	3.0 g/hp-hr

The EPA anticipates that, in some cases, affected engines will need to install NOx 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

**Commented [EO 12866216]:** This reads as if facility-wide average is this intended to function as a within-facility trading program of sorts (intriguing). Are these sources subject to sufficient emissions monitoring requirements to facilitate such "trading"?

**Commented [EPA217R216]:** The emissions units subject to the emissions averaging plan are subject to the same requirement as other affected engines. We have designed the monitoring and recordkeeping requirements to either allow for CEMS or annual testing and parametric monitoring necessary to calculate compliance with the averaging plan on a daily basis.

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<sub>x</sub> emissions limits for both rich- and lean burn engines burning natural gas at 0.7 g/hp-hr.

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*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<sub>x</sub> 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<sub>x</sub> controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO<sub>x</sub> 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 notice.

#### 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO<sub>x</sub> 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.<sup>393</sup> The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for this emissions limit.

**Commented [EO 12866218]:** “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.” Consider adding more explanation of why this level is cost-effective and sufficient.

**Commented [EPA219R218]:** Additional text added to explain why the 3.0 g/hp-hr limit is cost effective and sufficient compared to lower limits.

<sup>393</sup> 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).

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<sub>x</sub> emissions (in tons per day) that would be emitted if each covered unit individually met the

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applicable NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> reductions, and that many states built their revised SIPs around the emissions averaging approach addressed in this guidance document.<sup>394</sup> 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

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<sup>394</sup> 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<sub>x</sub>)—Stationary Reciprocating Internal Combustion Engines.”



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application of the emissions standards, a reduced impact on natural gas capacity, and a means for addressing the problem presented by achieving 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.<sup>395</sup> 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

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<sup>395</sup> 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.

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regulations,<sup>396</sup> 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<sub>x</sub> 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<sub>x</sub> emissions (in tpy~~d~~) allowed facility-wide based on the unit-specific NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Emissions* (October 17, 2012). For the remaining engines identified as

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<sup>396</sup> 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 categorical exclusion of vessel activities from this definition); see also 40 CFR 70.2 (defining “major source” for title V operating permits).

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uncontrolled, the EPA assumed a NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions limits in § 52.41(c). The owner or operator of such a facility must submit a

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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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 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<sub>x</sub> emissions are no more than 75 percent of permitted NO<sub>x</sub> 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

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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<sub>x</sub>. 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Emissions Limits for Kiln Types in Cement and Concrete Product Manufacturing**

<b>Kiln Type</b>	<b>NO<sub>x</sub> Emissions Limit (lb/ton of clinker)</b>
Long Wet	4.0
Long Dry	3.0
Preheater	3.8



<b>Kiln Type</b>	<b>NO<sub>x</sub> Emissions Limit (lb/ton of clinker)</b>
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-precalfiner 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Control Technologies for the Cement Industry, Final Report,” SNCR is not an appropriate NO<sub>x</sub> 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<sub>x</sub> emissions levels of 1.95 lb/ton of clinker or less. The commenter stated that the EPA should revise its assessment of potential NO<sub>x</sub> 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<sub>x</sub> 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

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conduct stack tests during the ozone season.

*Response:* Affected kilns that operate a NO<sub>x</sub> 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<sub>x</sub> 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.<sup>397</sup> 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

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<sup>397</sup> 40 CFR 63.11237 “Calendar year” defined as the period between January 1 and December 31, inclusive, for a given year.

~~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. Given the widespread use of SNCR as the preferred method of post-combustion NO<sub>x</sub> control for cement kilns and the use of CEMS associated with that method of control, the EPA is finalizing requirements for affected units in the cement industry to use 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<sub>x</sub> 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<sub>x</sub>. ~~After review of all available information received during public comment, the EPA has determined that there is sufficient information to determine that low-NO<sub>x</sub> 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<sub>x</sub> burners installed and has concluded that low-NO<sub>x</sub> burners are a readily available and widely implemented emissions~~

**Commented [EO 12866220]:** Can you add a brief explanation of why the rule does apply to reheat furnaces?

**Commented [EPA221R220]:** Added more information and cited to the extensive discussion in the TSD.

reduction strategy.<sup>398</sup> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> technology utilized at furnaces, kilns,

<sup>398</sup> See Final Non-EGU Sectors TSD, Section 4.

**Commented [EO 12866222]:** Can EPA further discuss the constraints that are faced by these portions of the iron and steel industry? It appears such comments were compelling, and possibly provided EPA with additional data to consider. Please summarize in the above section

**Commented [EPA223R222]:** Added a reference to the detailed discussion in the Final Non-EGU Sectors TSD regarding the concerns raised by commenters for application of SCR on these units.

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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<sub>x</sub> 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<sub>x</sub> controls, including SCR or other NO<sub>x</sub> 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. However, given the absence of information indicating that low-NO<sub>x</sub> control technologies are currently achievable and cost effective for these particular types of existing emissions units in this industry, the EPA is not finalizing regulatory requirements for these emissions units at this time. We provide a more detailed discussion of the economic and technical issues associated with implementation of NO<sub>x</sub> 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<sub>x</sub> controls (e.g., low-NO<sub>x</sub> 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<sub>x</sub> 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.”

*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<sub>x</sub> burners designed to reduce NO<sub>x</sub> 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<sub>x</sub> burner shall be designed to achieve at least 40 percent NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emitted per production hour), pounds per energy unit (i.e., million British thermal unit (mmBtu)), or pounds of NO<sub>x</sub> 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<sub>x</sub> burners and achieving emissions rates as low as 0.11 lb/mmBtu of NO<sub>x</sub>. 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<sub>x</sub> burners and are achieving various emissions rates.<sup>399</sup>

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

<sup>399</sup> Specifically, through a review of title V permits, the EPA identified reheat furnaces with low-NO<sub>x</sub> 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.

requiring the installation of low-NO<sub>x</sub> burners or equivalent low-NO<sub>x</sub> technology designed to achieve a minimum 40 percent reduction from baseline NO<sub>x</sub> 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<sub>x</sub> burner or alternative low-NO<sub>x</sub> 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<sub>x</sub> 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.

~~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<sub>x</sub> burners and source specific emissions limits to be set thereafter based on testing.~~

*Comment:* One commenter stated that the standard practice for setting NO<sub>x</sub> 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<sub>x</sub> emissions limits that will universally apply to multiple, unique facilities. The same commenter stated that NO<sub>x</sub> reduction in certain furnaces is routinely achievable by combustion controls or measures other than SCR.

**Commented [EO 12866224]:** Can EPA please elaborate how it will establish source-specific emissions limits, if not in this rule? Does this rule include an equation that would define such limits?

**Commented [EPA225R224]:** We have added a further explanation of the reg text which details the process for establishing a work plan to install the controls and set an emission limits.

**Commented [EO 12866226]:** Can EPA please elaborate how it will establish source-specific emissions limits, if not in this rule? Does this rule include an equation that would define such limits?

**Commented [EPA227R226]:** We have added a further explanation of the reg text which details the process for establishing a work plan to install the controls and set an emission limits.

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*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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> burners designed to reduce NO<sub>x</sub> 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<sub>x</sub> emissions from reheat furnaces using CEMS or annual performance testing and recordkeeping and operate low-NO<sub>x</sub> 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<sub>x</sub> control options that are achievable for these units, the EPA is finalizing requirements only for reheat furnaces at this time.

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*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 various RACT NO<sub>x</sub> 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 60 appendix A, 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<sub>x</sub> 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.

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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<sub>x</sub> emissions limits. Affected units that operate NO<sub>x</sub> 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

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or more of NO<sub>x</sub>. 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<sub>x</sub>). 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<sub>x</sub> 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<sub>x</sub> emissions to downwind receptors.

#### ***Emissions Limitations and Rationale***

The EPA is finalizing the proposed NO<sub>x</sub> 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

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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<sub>x</sub> 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<sub>x</sub> emissions limit for container glass manufacturing furnaces, while state and local NO<sub>x</sub> 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<sub>x</sub> emissions limit for pressed/blown glass manufacturing furnaces, while state and local NO<sub>x</sub> 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<sub>x</sub> emissions limit for flat glass manufacturing furnaces, while state NO<sub>x</sub> 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



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reviewed the control requirements or recommendations and related analyses in various RACT NO<sub>x</sub> rules, air permits, Alternative Control Techniques (ACT) documents, and consent decrees to determine the appropriate NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sup>400</sup> 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<sub>x</sub> 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

<sup>400</sup> For example, Pennsylvania’s RACT NO<sub>x</sub> emission limits for flat glass furnaces are 7.0 lbs of NO<sub>x</sub> 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>.

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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<sub>x</sub> emissions limits for glass manufacturing sources.<sup>401</sup> See 87 FR at 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<sub>x</sub> 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<sub>x</sub> Emissions Limits for Furnace Unit Types in Glass and Glass Product Manufacturing**

<b>Furnace Type</b>	<b>NO<sub>x</sub> Emissions Limit (lbs/ton of glass produced, 30 operating-day rolling average)</b>
Container Glass Manufacturing	4.0

<sup>401</sup> See [Proposed](#) Non-EGU Sectors TSD at 56, EPA-HQ-OAR-2021-0668-0145.

Furnace Type	NO <sub>x</sub> Emissions Limit (lbs/ton of glass produced, 30 operating-day rolling average)
Furnace	
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<sub>x</sub> emissions limits, or exceptions to the NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> limits during these periods.

*Response:* After review of the comments received and the EPA’s assessment of current practices within the glass manufacturing industry, the EPA is establishing provisions for

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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.<sup>402</sup> 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.<sup>403</sup> 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

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<sup>402</sup> See Pennsylvania Code, Title 25, Part I, Subpart C, Article III, Sections 129.305-129.307 (effective June 19, 2010), available at <http://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/currnrules/R4354%20051911.pdf>.

<sup>403</sup> 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).

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.<sup>404</sup> The EPA received numerous comments from the

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<sup>404</sup> See definitions in 40 CFR part 60 subpart CC.

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<sub>x</sub> emissions from the industry on a category-wide basis.<sup>405</sup> Therefore, the glass manufacturing industry has conducted various pollution prevention and research efforts to help identify preferred techniques for the control of NO<sub>x</sub>. Some of these studies revealed recent trends to control NO<sub>x</sub> 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<sub>x</sub> Emissions from Glass Manufacturing,"<sup>406</sup> glass manufacturing furnaces may utilize combustion modifications equivalent to low-NO<sub>x</sub> 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<sub>x</sub> removal efficiency. The EPA received numerous comments from the glass

<sup>405</sup> See Final Non-EGU Sectors TSD.

<sup>406</sup> EPA, Alternative Control Techniques Document – NO<sub>x</sub> Emissions from Glass Manufacturing, EPA-453/R-94-037, June 1994.

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<sub>x</sub> 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<sub>x</sub> emissions standards for glass manufacturing furnaces to install, calibrate, maintain and operate a CEMS for the measurement of NO<sub>x</sub> 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<sub>x</sub> emissions limits. Affected units that operate NO<sub>x</sub> 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***

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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<sub>x</sub> 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 of the notice. Additionally, we have determined that boilers meeting these applicability 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<sub>x</sub> 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<sup>407</sup> 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<sub>x</sub>. 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

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<sup>407</sup> See, e.g., 40 CFR 60.44b (Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units).

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<sub>x</sub> controls such as low-NO<sub>x</sub> 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<sub>x</sub> 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 of 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 meet the final rule, like SCR. The EPA does not have sufficient information at this time to conclude that units burning more

**Commented [EO 12866228]:** Is there any explanation for the choice of 90%?

**Commented [EPA229R228]:** EPA received comments received on the proposal indicating that interference with the proper functioning of control equipment can occur when other fuels, such as biomass, are introduced at levels above 10%.

**Commented [Round 2230R228]:** 3/9/2023: it would be helpful to add this explanation either to the comment summary or EPA’s response

**Commented [EPA231R228]:** Added to response.

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 ~~of~~ fuels other than coal, residual or distillate oil, 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<sub>x</sub> emissions limits for boilers burning combinations of coal, residual or distillate oil, or natural gas are consistent with the NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Emissions Limits for Boilers > 100 mmBtu/hr**

(Based on a 30-day rolling average)

Unit type	Emissions limit (lbs NO <sub>x</sub> /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 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<sub>x</sub> emissions limits have not been established for industrial sources of this pollutant. In light of this, NO<sub>x</sub> 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<sub>x</sub> 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

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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<sub>x</sub> 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<sub>x</sub> emissions. We anticipate the MACT program's boiler tune-up requirement should reduce NO<sub>x</sub> 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<sub>x</sub> emissions limit of 0.03 lb/mmBtu at petroleum refineries. The commenter noted that CEMs data shows a residual oil-

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fired boiler at the Ravenswood Steam Plant in New York achieves an average NO<sub>x</sub> emissions rate of 0.0716 lb NO<sub>x</sub> /MMBtu and that CEMS data shows that a gas-fired boiler in Johnsonville, Tennessee, achieves an average NO<sub>x</sub> emissions rate of 0.0058 lb NO<sub>x</sub>/mmBTU. Regarding coal-fired boilers, the commenter stated that a coal boiler at the Ingredion Incorporated Argo Plant in Illinois achieves an average NO<sub>x</sub> emissions rate of 0.1153 lb NO<sub>x</sub> / MMBtu with selective non-catalytic control technology, and the Axiall Corporation facility in West Virginia achieves a 0.1162 lb/mmBtu using low-NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> limit of less than 0.0400 lb/mmBtu.

*Response:* The EPA's intent was not to set the NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions limit of 0.2 lb/mmBtu on a 30-day rolling average basis. Various forms of combustion and post-combustion NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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

**Commented [EO 12866232]:** This answer includes a potential exemption for technical impossibility but it doesn't really seem responsive to the comment about technical challenges (which may not rise to the level of impossibility).

**Commented [EPA233R232]:** We have added additional explanation here and in the next paragraph. Sources that experience technical challenges but do not meet the criteria in the final rule for a case-by-case limit (*i.e.*, based on a showing of technical impossibility or extreme economic hardship) will remain subject to the applicable emissions limits in the final rule.

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on emissions limits and control technology for some units, it only provides information on a relatively small number of units subject to NO<sub>x</sub> emissions limits and operating NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions. This information is available in the docket for this final rule.

All affected units must install and operate NO<sub>x</sub> 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<sub>x</sub> emissions limit of 0.2 lb/mmBtu<sup>408</sup> for residual oil-fired boilers and proposed a NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> control equipment installed to meet the requirements in 40 CFR 60.44b (subpart Db of 40 CFR part 60, Standards of Performance for

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<sup>408</sup> 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.

Industrial-Commercial-Institutional Steam Generating Units), which already requires that natural gas-fired units meet a NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 Section 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 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.<sup>409</sup> 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,<sup>410</sup> 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<sub>x</sub> Emissions Limits for Large Municipal Waste Combustors**

<b>NO<sub>x</sub> Limit (ppmvd) corrected to 7 percent oxygen</b>	<b>Averaging Period</b>
110	24-hour
105	30-day

At proposal, the EPA noted that the NO<sub>x</sub> 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<sub>x</sub> limits for

<sup>409</sup> See the Final Non-EGU Sectors TSD for additional information on this inventory.

<sup>410</sup> See the Final Non-EGU Sectors TSD for additional information on the calculation of PTE for large MWCs.

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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<sub>x</sub> 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.<sup>411</sup>

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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> reductions could be achieved at costs ranging from \$2,900 to \$6,600 per ton of NO<sub>x</sub> 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.

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<sup>411</sup> For further discussion of the permits reviewed, see the Final Non-EGU Sectors TSD.

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*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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub>) on a 30-day rolling

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average and 110 ppmvd at 7 percent O<sub>2</sub> 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.

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<sub>x</sub> technology in addition to SNCR.<sup>412</sup> The EPA recognizes that not all units can implement low NO<sub>x</sub> technology, including those using Airedale 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 Airedale grate technology. One affected unit is classified as CLEERGAS gasification while the remaining 64 affected units are

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<sup>412</sup> The only demonstrated use of low NO<sub>x</sub> technology in addition to SNCR at MWC facilities is at Covanta facilities using Covanta's proprietary low NO<sub>x</sub> combustion system (LN<sup>TM</sup>). 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<sub>x</sub> technology could become available, or facilities could work with Covanta to apply this technology to their units.

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classified as mass burn waterwall combustors, which have not been explicitly identified as units unable to install low NO<sub>x</sub> technology. For those units unable to install low NO<sub>x</sub> technology or SNCR, the EPA has identified ASNCR 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> technology to existing SNCR.<sup>413</sup> Of the 80 MWC units

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<sup>413</sup> See OTC MWC Report at 6-7; Trinity Consultants, *Project Report Covanta Alexandria/Arlington, Inc., Reasonably Available Control Technology Determination for NO<sub>x</sub>* (September 2017); Trinity Consultants, *Project Report Covanta Fairfax, Inc., Reasonably Available Control Technology Determination for NO<sub>x</sub>* (September 2017); Babcock Power Environmental, *Waste to Energy NO<sub>x</sub> 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<sub>x</sub>, 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 Reference to Covanta Energy Group, Inc.

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subject to this rule, 55 units already have SNCR installed, 16 units already have SNCR and low NO<sub>x</sub> 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<sub>x</sub> technology to eligible units with SNCR was found to be approximately \$7,929.02/ton.<sup>414</sup> 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<sub>x</sub> 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<sub>x</sub> CEMS data electronically

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Essex County Resource Recovery Facility, Newark Annual Stack Test Program (March 14, 2019).

<sup>414</sup> See Final Non-EGU Sectors TSD for more information on these cost effectiveness estimates were generated.



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<sub>x</sub> 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<sub>x</sub> emissions discharged into the atmosphere from the affected facility. This is consistent with NSPS requirements for large MWCs under 40 CFR 60 subparts Ea and Eb, and state RACT rules that are applicable to MWCs in many of the states covered under this rulemaking.<sup>415</sup> 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 of the notice, the EPA also recognizes that states retain the discretion to

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<sup>415</sup> 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).

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, 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<sub>x</sub> 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;

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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

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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 of the notice, 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 of the notice, 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.<sup>416</sup>

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

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<sup>416</sup> 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 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.

PM<sub>2.5</sub> 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<sub>2.5</sub>) NAAQS—because NO<sub>x</sub> is a precursor to PM<sub>2.5</sub> as well as ozone—have relied in part on the NO<sub>x</sub> 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.

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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 notice, 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 **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** 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 **[INSERT DATE 90 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. If a state

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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 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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

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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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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

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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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 Trading Program. For a transport SIP revision that does not use the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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 proposed 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<sub>x</sub> 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

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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<sub>x</sub> 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 notice.

*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



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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.<sup>417</sup> 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,

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<sup>417</sup> Part 70 addresses requirements for state title V programs, and Part 71 governs the federal title V program.

“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)).<sup>418</sup> 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

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<sup>418</sup> 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).

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standard requirements governing how sources covered by those rules would comply with title V and its regulations.<sup>419</sup> 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<sub>x</sub> 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

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<sup>419</sup> 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](https://www.epa.gov/sites/default/files/2016-10/documents/csapr_title_v_permit_guidance.pdf).

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 40 CFR 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.<sup>420</sup> 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 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

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<sup>420</sup> *Id.*

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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.<sup>421</sup> 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<sub>x</sub> SIP Call

Sources in states affected by both the NO<sub>x</sub> 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<sub>x</sub> ozone season emissions reductions from these sources in many of the NO<sub>x</sub> SIP Call states, and at greater stringency than required by the NO<sub>x</sub> SIP Call, by requiring the EGUs to participate in the CSAPR NO<sub>x</sub> 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<sub>x</sub> SIP Call for these large EGUs.

With respect to the large non-EGU boilers and combustion turbines that formerly

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<sup>421</sup> <https://www.epa.gov/airmarkets/part-75-petition-responses>.

participated in the NO<sub>x</sub> Budget Trading Program under the NO<sub>x</sub> SIP Call, the EPA provided options under both the CSAPR Update and the Revised CSAPR Update for states to address these sources' ongoing NO<sub>x</sub> SIP Call requirements by expanding applicability of the relevant CSAPR trading programs for ozone season NO<sub>x</sub> 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.<sup>422</sup>

## 2. Acid Rain Program

This rule does not affect any SO<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> 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<sub>x</sub> Annual, CSAPR SO<sub>2</sub> Group 1, CSAPR SO<sub>2</sub> Group 2, CSAPR NO<sub>x</sub> Ozone Season Group 1, or CSAPR NO<sub>x</sub> 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

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<sup>422</sup> Only one NO<sub>x</sub> 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<sub>x</sub> 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).

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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<sub>x</sub> Ozone Season Group 2 Trading Program (or earlier by the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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.<sup>423</sup>

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<sup>423</sup> 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.



## 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.<sup>424</sup> Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through federal government actions.<sup>425</sup> 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.”<sup>426</sup> In recognizing that minority and low-

<sup>424</sup> 59 FR 7629, February 16, 1994.

<sup>425</sup> 86 FR 7009, January 20, 2021.

<sup>426</sup> <https://www.epa.gov/environmentaljustice>.

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 technical guidance<sup>427</sup> states that “[t]he 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

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<sup>427</sup> U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

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there are potential EJ concerns for population groups of concern in the baseline (question 1).<sup>428</sup> 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<sub>2.5</sub> 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<sub>2.5</sub> metric is more similar to the long term PM<sub>2.5</sub> 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<sup>2</sup>. 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

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<sup>428</sup> 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).

disadvantaged populations (Section 7.3); and 2) the potential for disproportionate ozone and PM<sub>2.5</sub> 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<sub>2</sub> 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<sub>2</sub>) 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<sub>2.5</sub> 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<sub>2.5</sub> 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<sub>2.5</sub> analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less educated, and children may experience somewhat higher ozone and PM<sub>2.5</sub> 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<sub>2.5</sub> 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<sub>2.5</sub> 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<sub>2.5</sub> exposure impacts across populations, we do not find evidence that

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potential EJ concerns related to ozone and PM<sub>2.5</sub> concentrations will be created or mitigated as compared to the baseline.<sup>429</sup>

### 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.<sup>430</sup> 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.<sup>431</sup> 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.

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<sup>429</sup> 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

<sup>430</sup> This does not constitute EPA's tribal consultation under EO 13175, which is described in Section XI.F of this proposed rule.

<sup>431</sup> Comments and responses regarding environmental justice considerations are available in [Section 6](#) of the RTC document 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<sub>x</sub> emissions requirements presented in Section I.B of this notice.

For EGUs, the EPA analyzed this action’s emissions budgets using uniform control stringency represented by \$1,800 per ton of NO<sub>x</sub> (2016\$) in 2023 and \$11,000 per ton of NO<sub>x</sub> (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<sub>x</sub> 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*”

**Commented [EO 12866234]:** EPA should consider recognizing in this narrative that implementation of the IRA may have effects on these estimates

**Commented [EPA235R234]:** We would like to discuss this comment further.

**Commented [EPA236R234]:** Discussed on 3/10 teleconference.

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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 ~~Technical Support Document (TSD)~~ 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<sub>x</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, and CO<sub>2</sub> 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<sub>x</sub> Emissions Changes and Annual Emissions Reductions (tons) for NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, and CO<sub>2</sub> for the Regulatory Control Alternatives from 2023 - 2042**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>2023</b>			
NO <sub>x</sub> (ozone season)	10,000	10,000	10,000
NO <sub>x</sub> (annual)	15,000	15,000	15,000
SO <sub>2</sub> (annual)	1,000	3,000	1,000

**Commented [EO 12866237]:** Why does the less stringent alternative have greater SO<sub>2</sub> emissions reductions in 2023?

**Commented [EPA238R237]:** Under the less stringent scenario, one model plant in Texas switches to burning a larger quantity of lower sulphur lignite coal. This in turn results in lower emissions than under the final rule and more stringent alternative.



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	<b>Final Rule</b>	<b>Less Stringent Alternative</b>	<b>More Stringent Alternative</b>
CO <sub>2</sub> (annual, thousand metric tons)	-	-	-
PM <sub>2.5</sub> (annual)	-	-	-
<b>2024</b>			
NOx (ozone season)	21,000	10,000	33,000
NOx (annual)	25,000	15,000	57,000
SO <sub>2</sub> (annual)	19,000	5,000	59,000
CO <sub>2</sub> (annual, thousand metric tons)	10,000	4,000	20,000
PM <sub>2.5</sub> (annual)	1,000	-	1,000
<b>2025</b>			
NOx (ozone season)	32,000	10,000	56,000
NOx (annual)	35,000	15,000	99,000
SO <sub>2</sub> (annual)	38,000	7,000	118,000
CO <sub>2</sub> (annual, thousand metric tons)	21,000	8,000	40,000
PM <sub>2.5</sub> (annual)	2,000	1,000	2,000
<b>2026</b>			
NOx (ozone season)	25,000	8,000	49,000
NOx (annual)	29,000	12,000	88,000
SO <sub>2</sub> (annual)	29,000	5,000	104,000
CO <sub>2</sub> (annual, thousand metric tons)	16,000	6,000	34,000
PM <sub>2.5</sub> (annual)	1,000	-	2,000
<b>2027</b>			
NOx (ozone season)	19,000	6,000	43,000
NOx (annual)	22,000	9,000	78,000
SO <sub>2</sub> (annual)	21,000	4,000	91,000
CO <sub>2</sub> (annual, thousand metric tons)	10,000	3,000	28,000
PM <sub>2.5</sub> (annual)	1,000	-	2,000
<b>2030</b>			
NOx (ozone season)	34,000	33,000	31,000
NOx (annual)	62,000	59,000	50,000
SO <sub>2</sub> (annual)	93,000	98,000	51,000
CO <sub>2</sub> (annual, thousand metric tons)	26,000	23,000	8,000
PM <sub>2.5</sub> (annual)	1,000	1,000	-
<b>2035</b>			
NOx (ozone season)	29,000	30,000	27,000
NOx (annual)	46,000	46,000	41,000
SO <sub>2</sub> (annual)	21,000	19,000	15,000

	Final Rule	Less Stringent Alternative	More Stringent Alternative
CO <sub>2</sub> (annual, thousand metric tons)	16,000	15,000	8,000
PM <sub>2.5</sub> (annual)	1,000	1,000	-
<b>2042</b>			
NO <sub>x</sub> (ozone season)	22,000	22,000	22,000
NO <sub>x</sub> (annual)	23,000	22,000	21,000
SO <sub>2</sub> (annual)	15,000	15,000	7,000
CO <sub>2</sub> (annual, thousand metric tons)	9,000	8,000	4,000
PM <sub>2.5</sub> (annual)	-	-	-

Emissions changes for NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>2.5</sub> are in tons.

Table VIII-2 provides a summary of the ozone season NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Emissions and Emissions Reductions (tons) for Non-EGUs for the Final Rule and the Less and More Stringent Alternatives**

State	2019 Ozone Season Emissions <sup>a</sup>	Final Rule – Ozone Season NO <sub>x</sub> Reductions	Less Stringent – Ozone Season NO <sub>x</sub> Reductions	More Stringent – Ozone Season NO <sub>x</sub> 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
NJ	2,078	242	242	258

**Commented [EO 12866239]:** Why does the more stringent version have lower reductions in the outer years?

**Commented [EPA240R239]:** The more stringent scenario assumes imposition of the backstop emission rate in the 2025 run year rather than the 2030 run year. This in turn results in additional SCR installation relative to the Final rule (which instead sees higher retirements in 2030). Under the Final rule, capacity that retires in 2030 is replaced with lower emitting technology. As a result emissions are higher under the more stringent scenario in later years.

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NV <sup>432</sup>	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
<b>Totals</b>	<b>302,425</b>	<b>44,616</b>	<b>16,786</b>	<b>67,728</b>

<sup>a</sup> 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<sub>x</sub> 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.

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

<sup>432</sup> 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.

**Commented [EO 12866241]:** Where are these files made publicly available? Add a link

**Commented [EPA242R241]:** The EPA only keeps updated/current versions of inventory files available on the ftp site; these specific files are not available on the ftp site. These specific files are located in the zip file of data and code used in the non-EGU analyses. The zip file is available through the docket office -- *Final GNP RIA Non-EGU Analysis Files.zip*.

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<sup>433</sup>. 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**

		<b>Final Rule</b>	<b>Less-Stringent Alternative</b>	<b>More-Stringent Alternative</b>
<b>2023</b>	<b>EGUs</b>	-57	-56	-49
	<b>Non-EGUs</b>	-	-	-
	<b>Total</b>	-57	-56	-49
<b>2026</b>	<b>EGUs</b>	(-5)	(-35)	-840
	<b>Non-EGUs</b>	-570	-140	-1,300
	<b>Total</b>	-570	-110	-2,100
<b>2027</b>	<b>EGUs</b>	-24	(-47)	-760
	<b>Non-EGUs</b>	-570	-140	-1,300
	<b>Total</b>	-600	-97	-2,000
<b>2030</b>	<b>EGUs</b>	-710	-770	-840
	<b>Non-EGUs</b>	-570	-140	-1,300

<sup>433</sup> 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.

Commented [Round 3243]: 3/13: new text

Commented [EPA244R243]: Edit accepted.

Commented [EO 12866245]: Is this a realistic treatment of costs over time, or just a quirk of the model? It reads as the latter. If the former, please clarify that EPA expects firms to make such decisions and why.

Commented [EPA246R245]: The rule results in early retirement of some coal EGUs that face challenging economics in the near term, but whose economic position improves later in the forecast period due to other asset retirements and demand growth. As such total costs are lower in the near term (with a single year negative point estimate) and higher in the longer term.

Commented [Round 2247R245]: 3/9/2023: would EPA be open to zeroing out the negative costs in the relevant year? This explanation does not necessarily sound like the affected facilities/units are actually experiencing negative costs but rather that the timeframe of various costs is shifting and is reflected by the model as a negative value

Commented [EPA248R245]: In lieu of zeroing out costs, in Chapter 4, Section 4.5.2 of the RIA we included the following language: *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 this RIA.*

Commented [Round 3249R245]: 3/13: added as a footnote

Commented [EPA250R245]: Edit accepted – we added a cross-reference to the relevant RIA section.

Commented [EO 12866251]: Please provide a total compliance cost across all years analyzed (2023-2042)

Commented [EPA252R251]: We replaced the table.

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	<b>Total</b>	<b>-1,300</b>	<b>-920</b>	<b>-2,100</b>
<b>2035</b>	<b>EGUs</b>	<b>-820</b>	<b>-850</b>	<b>-590</b>
	<b>Non-EGUs</b>	<b>-570</b>	<b>-140</b>	<b>-1,300</b>
	<b>Total</b>	<b>-1,400</b>	<b>-990</b>	<b>-1,900</b>
<b>2042</b>	<b>EGUs</b>	<b>-820</b>	<b>-830</b>	<b>-600</b>
	<b>Non-EGUs</b>	<b>-570</b>	<b>-140</b>	<b>-1,300</b>
<b>-</b>	<b>Total</b>	<b>-1,400</b>	<b>-970</b>	<b>-1,900</b>

		<u>Final Rule</u>	<u>Less-Stringent Alternative</u>	<u>More-Stringent Alternative</u>
<u>2023</u>	<u>EGUs</u>	<u>57</u>	<u>56</u>	<u>49</u>
	<u>Non-EGUs</u>	<u>--</u>	<u>--</u>	<u>--</u>
	<b>Total</b>	<b>57</b>	<b>56</b>	<b>49</b>
<u>2024</u>	<u>EGUs</u>	<u>(5)</u>	<u>(35)</u>	<u>840</u>
	<u>Non-EGUs</u>	<u>--</u>	<u>--</u>	<u>--</u>
	<b>Total</b>	<b>(5)</b>	<b>(35)</b>	<b>840</b>
<u>2025</u>	<u>EGUs</u>	<u>(5)</u>	<u>(35)</u>	<u>840</u>
	<u>Non-EGUs</u>	<u>--</u>	<u>--</u>	<u>--</u>
	<b>Total</b>	<b>(5)</b>	<b>(35)</b>	<b>840</b>
<u>2026</u>	<u>EGUs</u>	<u>(5)</u>	<u>(35)</u>	<u>840</u>
	<u>Non-EGUs</u>	<u>570</u>	<u>140</u>	<u>1,300</u>
	<b>Total</b>	<b>570</b>	<b>110</b>	<b>2,100</b>
<u>2027</u>	<u>EGUs</u>	<u>24</u>	<u>(47)</u>	<u>760</u>
	<u>Non-EGUs</u>	<u>570</u>	<u>140</u>	<u>1,300</u>
	<b>Total</b>	<b>600</b>	<b>97</b>	<b>2,000</b>
<u>2028</u>	<u>EGUs</u>	<u>24</u>	<u>(47)</u>	<u>760</u>
	<u>Non-EGUs</u>	<u>570</u>	<u>140</u>	<u>1,300</u>
	<b>Total</b>	<b>600</b>	<b>97</b>	<b>2,000</b>
<u>2029</u>	<u>EGUs</u>	<u>24</u>	<u>(47)</u>	<u>760</u>
	<u>Non-EGUs</u>	<u>570</u>	<u>140</u>	<u>1,300</u>
	<b>Total</b>	<b>600</b>	<b>97</b>	<b>2,000</b>
<u>2030</u>	<u>EGUs</u>	<u>710</u>	<u>770</u>	<u>840</u>
	<u>Non-EGUs</u>	<u>570</u>	<u>140</u>	<u>1,300</u>
	<b>Total</b>	<b>1,300</b>	<b>920</b>	<b>2,100</b>
<u>2031</u>	<u>EGUs</u>	<u>710</u>	<u>770</u>	<u>840</u>
	<u>Non-EGUs</u>	<u>570</u>	<u>140</u>	<u>1,300</u>
	<b>Total</b>	<b>1,300</b>	<b>920</b>	<b>2,100</b>
<u>2032</u>	<u>EGUs</u>	<u>820</u>	<u>850</u>	<u>590</u>
	<u>Non-EGUs</u>	<u>570</u>	<u>140</u>	<u>1,300</u>
	<b>Total</b>	<b>1,400</b>	<b>990</b>	<b>1,900</b>
<u>2033</u>	<u>EGUs</u>	<u>820</u>	<u>850</u>	<u>590</u>
	<u>Non-EGUs</u>	<u>570</u>	<u>140</u>	<u>1,300</u>

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		<u>Final Rule</u>	<u>Less-Stringent Alternative</u>	<u>More-Stringent Alternative</u>
	<b>Total</b>	<b>1,400</b>	<b>990</b>	<b>1,900</b>
<u>2034</u>	EGUs	820	850	590
	Non-EGUs	570	140	1,300
	<b>Total</b>	<b>1,400</b>	<b>990</b>	<b>1,900</b>
<u>2035</u>	EGUs	820	850	590
	Non-EGUs	570	140	1,300
	<b>Total</b>	<b>1,400</b>	<b>990</b>	<b>1,900</b>
<u>2036</u>	EGUs	820	850	590
	Non-EGUs	570	140	1,300
	<b>Total</b>	<b>1,400</b>	<b>990</b>	<b>1,900</b>
<u>2037</u>	EGUs	820	850	590
	Non-EGUs	570	140	1,300
	<b>Total</b>	<b>1,400</b>	<b>990</b>	<b>1,900</b>
<u>2038</u>	EGUs	820	830	600
	Non-EGUs	570	140	1,300
	<b>Total</b>	<b>1,400</b>	<b>970</b>	<b>1,900</b>
<u>2039</u>	EGUs	820	830	600
	Non-EGUs	570	140	1,300
	<b>Total</b>	<b>1,400</b>	<b>970</b>	<b>1,900</b>
<u>2040</u>	EGUs	820	830	600
	Non-EGUs	570	140	1,300
	<b>Total</b>	<b>1,400</b>	<b>970</b>	<b>1,900</b>
<u>2041</u>	EGUs	820	830	600
	Non-EGUs	570	140	1,300
	<b>Total</b>	<b>1,400</b>	<b>970</b>	<b>1,900</b>
<u>2042</u>	EGUs	820	830	600
	Non-EGUs	570	140	1,300
	<b>Total</b>	<b>1,400</b>	<b>970</b>	<b>1,900</b>

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<sub>2.5</sub> 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\$)<sup>a,b</sup>**

Disc. Rate	Pollutant	Final Rule	Less Stringent Alternative	More Stringent Alternative
3%	Ozone Benefits	\$100 (\$27 to \$220) <sup>d</sup>	\$820 (\$91 to \$2,100) <sup>d</sup>	\$810 (\$91 to \$2,100) <sup>d</sup>
7%	Ozone Benefits	\$93 (\$17 to 210) <sup>e</sup>	\$730 (\$75 to \$1,900) <sup>d</sup>	\$730 (\$75 to \$1,900) <sup>d</sup>

Disc Rate	Pollutant	Final Rule	Less Stringent Alternative	More Stringent Alternative
3%	Ozone Benefits	\$100 [\$27 to \$220] <sup>c</sup>	\$820 [\$91 to \$2,100] <sup>d</sup>	\$810 [\$91 to \$2,100] <sup>d</sup>
7%	Ozone Benefits	\$93 [\$17 to 210] <sup>c</sup>	\$730 [\$75 to \$1,900] <sup>d</sup>	\$730 [\$75 to \$1,900] <sup>d</sup>

**Commented [EO 12866253]:** Table appears to have fixable formatting issues

**Commented [EPA254R253]:** Thank you. We replaced the table.

**Commented [EO 12866255]:** Presenting these in parentheses suggests that they are negative values. Could EPA instead add as a separate row so that parens are unneeded?

**Commented [EPA256R255]:** We attempted to add additional rows and the table below became challenging. We swapped out parentheses for brackets to avoid confusion over negative numbers.

**Commented [Round 2257R255]:** 3/9/2023: thanks, that works

<sup>a</sup> 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

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not be summed.

<sup>b</sup> We estimated ozone benefits for changes in NO<sub>x</sub> 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.

<sup>c</sup> Using the pooled short-term ozone exposure mortality risk estimate.

<sup>d</sup> Using the long-term ozone exposure mortality risk estimate.



**Table VIII-5: Estimated Discounted Economic Value of Avoided Ozone and PM<sub>2.5</sub>-Related Premature Mortality and Illness for the Final Rule and the Less and More Stringent Alternatives in 2026 (95% Confidence Interval; millions of 2016\$)<sup>a,b</sup>**

Disc Rate	Pollutant	Final Rule		Less Stringent Alternative			More Stringent Alternative			
3%	Ozone Benefits	\$1,100 [\$280 to \$2,400] <sup>c</sup>	and	\$9,400 [\$1,000 to \$25,000] <sup>d</sup>	\$420 [\$110 to \$900] <sup>c</sup>	and	\$3,400 [\$380 to \$8,900] <sup>d</sup>	\$1,900 [470 to \$4,000] <sup>c</sup>	and	\$15,000 [\$1,700 to \$40,000] <sup>d</sup>
	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] <sup>c</sup>	and	\$14,000 [\$1,500 to \$36,000] <sup>d</sup>	\$950 [\$160 to \$2,300] <sup>c</sup>	and	\$4,600 [\$490 to \$12,000] <sup>d</sup>	\$8,300 [\$1,200 to \$21,000] <sup>c</sup>	and	\$29,000 [\$3,000 to \$77,000] <sup>d</sup>
7%	Ozone Benefits	\$1,000 [\$180 to \$2,300] <sup>c</sup>	and	\$8,400 [\$850 to \$22,000] <sup>d</sup>	\$380 [\$68 to \$850] <sup>c</sup>	and	\$3,100 [\$310 to \$8,100] <sup>d</sup>	\$1,700 [\$300 to \$3,800] <sup>c</sup>	and	\$14,000 [\$1,400 to \$36,000] <sup>d</sup>
	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] <sup>c</sup>	and	\$12,000 [\$1,200 to \$33,000] <sup>d</sup>	\$850 [\$120 to \$2,100] <sup>c</sup>	and	\$4,100 [\$410 to \$11,000] <sup>d</sup>	\$7,500 [\$910 to \$19,000] <sup>c</sup>	and	\$26,000 [\$2,600 to \$69,000] <sup>d</sup>
Disc Rate	Pollutant	Final Rule		Less Stringent Alternative			More Stringent Alternative			
3%	Ozone Benefits	\$1,100 ((\$280 to \$2,400)) <sup>c</sup>	and	\$9,400 ((\$1,000 to \$25,000)) <sup>d</sup>	\$420 ((\$110 to \$900)) <sup>c</sup>	and	\$3,400 ((\$380 to \$8,900)) <sup>d</sup>	\$1,900 (470 to \$4,000) <sup>c</sup>	and	\$15,000 ((\$1,700 to \$40,000)) <sup>d</sup>
	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)) <sup>c</sup>	and	\$14,000 ((\$1,500 to \$36,000)) <sup>d</sup>	\$950 ((\$160 to \$2,300)) <sup>c</sup>	and	\$4,600 ((\$490 to \$12,000)) <sup>d</sup>	\$8,300 ((\$1,200 to \$21,000)) <sup>c</sup>	and	\$29,000 ((\$3,000 to \$77,000)) <sup>d</sup>
7%	Ozone Benefits	\$1,000 ((\$180 to \$2,300)) <sup>c</sup>	and	\$8,400 ((\$850 to \$22,000)) <sup>d</sup>	\$380 ((\$68 to \$850)) <sup>c</sup>	and	\$3,100 ((\$310 to \$8,100)) <sup>d</sup>	\$1,700 ((\$300 to \$3,800)) <sup>c</sup>	and	\$14,000 ((\$1,400 to \$36,000)) <sup>d</sup>
	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)) <sup>c</sup>	and	\$12,000 ((\$1,200 to \$33,000)) <sup>d</sup>	\$850 ((\$120 to \$2,100)) <sup>c</sup>	and	\$4,100 ((\$410 to \$11,000)) <sup>d</sup>	\$7,500 ((\$910 to \$19,000)) <sup>c</sup>	and	\$26,000 ((\$2,600 to \$69,000)) <sup>d</sup>

<sup>a</sup> 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.

<sup>b</sup> We estimated changes in NOx for the ozone season and annual changes in PM<sub>2.5</sub> and PM<sub>2.5</sub> precursors in 2026.

<sup>c</sup> Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Di et al. (2017) long-term PM<sub>2.5</sub> exposure mortality risk estimate.

<sup>d</sup> Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Di et al. (2017) long-term PM<sub>2.5</sub> 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<sub>2.5</sub> 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\$)<sup>a,b</sup>**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
Health Benefits <sup>c</sup>	\$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 <sup>d</sup>	\$57	\$56	\$49
<b>Net Benefits</b>	<b>\$48 and \$760</b>	<b>\$48 and \$760</b>	<b>\$66 and \$800</b>

<sup>a</sup> 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.

<sup>b</sup> Rows may not appear to add correctly due to rounding.

<sup>c</sup> 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.

<sup>d</sup> 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.](#)

**Commented [EO 12866258]:** Specify the discount rate used in the table header and use notes below to clarify any discrepancies. E.g., it's unclear whether all values are discounted to 3%, with some exceptions for EGU values? Same comment applies to following tables.

**Commented [EPA259R258]:** Discussed by teleconference 3/10. Added text to Table Note d to this table and the next 2 tables.

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**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\$)<sup>a,b</sup>**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>Health Benefits<sup>c</sup></b>	\$3,200 and \$14,000	\$950 and \$4,600	\$8,300 and \$29,000
<b>Climate Benefits</b>	\$1,100	\$420	\$2,100
<b>Total Benefits</b>	\$4,300 and \$15,000	\$1,400 and \$5,000	\$10,000 and \$31,000
<b>Costs<sup>d</sup></b>	\$570	\$110	\$2,100
<b>Net Benefits</b>	<b>\$3,700 and \$14,000</b>	<b>\$1,300 and \$4,900</b>	<b>\$8,300 and \$29,000</b>

<sup>a</sup> 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.

<sup>b</sup> Rows may not appear to add correctly due to rounding.

<sup>c</sup> 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.

<sup>d</sup> 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\$)<sup>a,b</sup>**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>Health Benefits<sup>c</sup></b>	\$3,400 and \$15,000	\$1,000 and \$4,900	\$9,000 and \$31,000
<b>Climate Benefits</b>	\$1,500	\$1,300	\$500
<b>Total Benefits</b>	\$4,900 and \$16,000	\$2,300 and \$6,200	\$9,500 and \$31,000
<b>Costs<sup>d</sup></b>	\$1,300	\$920	\$2,100
<b>Net Benefits</b>	<b>\$3,600 and \$15,000</b>	<b>\$1,400 and \$5,300</b>	<b>\$7,400 and \$29,000</b>

<sup>a</sup> 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.

<sup>b</sup> Rows may not appear to add correctly due to rounding.

<sup>c</sup> 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.

<sup>d</sup> 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

**Commented [EO 12866260]:** There may be reliability issues and other considerations before 2030 that justify EPA’s selection of the final rule over the more-stringent alternative, especially for EGUs, but are there any elements of the more-stringent alternative, such as the standards for the non-EGUs, that might be the better, more cost-effective choice either from the beginning, or else perhaps phased in over time?

**Commented [EPA261R260]:** The more stringent alternative for non-EGUs has costlier controls that are not widely demonstrated in practice. (i.e., SCR for cement kilns, glass furnaces).

Imposition of the backstop emission rate on coal units lacking existing SCR controls in the 2025 run year (as under the more stringent scenario) results in near term challenges around the volume of SCRs that would need to be procured and installed, and early retirement of units that could affect the tighter supply demand balance in the near term. By phasing in controls through 2030, more lead time is provided for procuring SCRs as well as fewer reliability concerns as a result of retirements later in the forecast period.

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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 Proposed Rule and Less and More Stringent Alternatives, 2023 Through 2042 (Millions 2016\$, Discounted to 2023)**

Health Benefits	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
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 <sup>a</sup>	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Final Rule	\$15,000	\$970	<del>\$15,000</del> A	<del>\$970</del> N/A
Less Stringent Alternative	\$11,000	\$770	<del>\$11,000</del> A	<del>\$770</del> N/A
More Stringent Alternative	\$14,000	\$920	<del>\$14,000</del> A	<del>\$920</del> N/A

Compliance Costs	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
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	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Final Rule	\$200,000	\$13,000	<del>\$130,000</del>	\$12,000
Less Stringent Alternative	\$70,000	\$4,700	\$42,000	\$4,000
More Stringent Alternative	\$400,000	\$27,000	\$240,000	\$22,000

**Commented [EO 12866262]:** EPA could add a note below to clarify that there are climate benefits vs. N/A but that such benefits are reported as discounted at 3%. See comments from exec summary.

**Commented [EPA263R262]:** We edited the table to be consistent with presentation in Executive Summary.

**Commented [EO 12866264]:** If the reported totals do not include climate benefits, please add them discounted at 3% and provide an explanatory note (see earlier table as example)

**Commented [EPA265R264]:** We edited the table to be consistent with Executive Summary and added table note.

<sup>a</sup> Climate benefits are calculated using four different estimates of the social cost of carbon (SC-CO<sub>2</sub>) (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<sub>2</sub> 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.

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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 notice), these results using full-scale photochemical grid modeling complement those estimates and confirm in all cases the regulatory conclusions

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reached applying AQAT.<sup>434</sup> 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.

#### **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

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<sup>434</sup> 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.

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obligations related to ozone in 40 CFR part 52 as well as the revisions to the regulations for the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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, subpartsBBBB, EEEEE, and GGGGG as constituting the relevant FIP provisions relating to seasonal NO<sub>x</sub> 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<sub>x</sub> emissions, SO<sub>2</sub> emissions, and transported fine particulate pollution.

The states whose EGU sources are required to participate in the CSAPR NO<sub>x</sub> 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.<sup>435</sup> The subparagraphs 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

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<sup>435</sup> Like the previous text of § 52.38(b)(2), the final amended text expressly encompasses sources in Indian country within the respective states' borders.



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.<sup>436</sup> 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).<sup>437</sup> The removal of the previous options for states to expand applicability of the trading programs for ozone season NO<sub>x</sub> emissions to certain non-EGUs and smaller EGUs, discussed in Sections VI.D.2 and VI.D.3, is

<sup>436</sup> 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).

<sup>437</sup> 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.

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 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.<sup>438</sup> 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<sub>x</sub> 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.

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<sup>438</sup> 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).

For each of the seven states that the EPA is proposing to remove 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.<sup>439</sup> 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<sup>440</sup> except as needed to update cross-references or to implement the proposed changes related to the treatment of Indian country, as discussed in Section IX.D.

<sup>439</sup> 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).

<sup>440</sup> 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).

#### *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<sub>x</sub> 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<sub>x</sub> emissions rate” and modification of the definition of “CSAPR NO<sub>x</sub> 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<sub>x</sub> 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 notice are implemented through revisions to multiple sections 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.<sup>441</sup> 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<sub>x</sub> 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 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.

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<sup>441</sup> 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).

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.<sup>442</sup> 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 2023 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

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<sup>442</sup> 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<sub>x</sub> 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.

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.<sup>443</sup> 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 proposed 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

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<sup>443</sup> 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.



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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 notice 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<sub>x</sub> emissions and the procedures for apportioning NO<sub>x</sub> 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 notice, 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. 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 notice is implemented at § 97.826(e).<sup>444</sup> 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 notice 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 notice, 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 proposed 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

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<sup>444</sup> 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.

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§§ 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<sub>x</sub> 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 notice, 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~~finalized in the Revised CSAPR Update relating to the “supplemental allowances” issued for the 2021 control period in formerly appearing 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 for the 2021 control period in § 97.1010(a)(1)(i) so as to include the amounts of 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. the supplemental allowances in the restated budget amounts. Similarly, the amounts of limits for the 2021 control period in § 97.1010(e)(1) are being restated so as to include to the 2021 assurance levels that was previously described separately in the regulations as 21 percent of the supplemental allowances. The revised language is substantively equivalent to and simple 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 notice.

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<sub>x</sub> Annual, SO<sub>2</sub> Group 1, and SO<sub>2</sub> 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.

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## X. Statutory and Executive Orders Reviews

Additional information about these statutes and Executive Orders (“EO”) can be found at <http://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 ~~an economically~~ 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 ~~OMB recommendations~~[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 notice.

### 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

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Rule (CSAPR) NO<sub>x</sub> Ozone Season Group 3 trading program addressing seasonal NO<sub>x</sub> emissions in various states. Under the amendments, all EGU sources in the original twelve Group 3 states (Illinois, Indiana, 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<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub>) emissions, annual nitrogen oxides (NO<sub>x</sub>) emissions, or seasonal NO<sub>x</sub> emissions in various sets of states, and the Texas SO<sub>2</sub> trading program which is modeled after CSAPR. This ICR accounts for the additional respondent burden related to the amendments to the CSAPR NO<sub>x</sub> 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.

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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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 or the CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season program. Sources in Minnesota are already reporting data for the CSAPR NO<sub>x</sub> Annual program with almost identical information collection requirements, requiring only a one-time monitoring plan and DAHS



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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

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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 2705.0~~22~~<sup>24</sup>. 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. 2705.0~~22~~<sup>24</sup> 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 (NOx) 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 Title 40, Chapter 1, Part 2, Subpart B, shall be maintained appropriately (see 40 CFR 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).

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*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+242

*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.

The specific frequency for each information collection activity within the non-EGU ICR is

**Commented [Round 2266]:** 3/9/2023: why did the total estimated cost and annualized capital costs change between 1<sup>st</sup> & 2<sup>nd</sup> rounds of review? These reductions are not linear with the changes to burden hours above

**Commented [EPA267R266]:** We adjusted cost estimates that affected line items other than burden hours in the ICR for non-EGU. Final ICR will be provided to OMB prior to publication of the final rule.

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~~shown at the end of the ICR document in Tables I through II. 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 engine maintenance recordkeeping is conducted quarterly. Reporting frequency is on a quarterly, semi-annual and annual basis.~~

~~Total estimated burden: 14,106 hours (per year). Burden is defined at 5 CFR 1320.3(b).~~

~~Total estimated cost: \$18,263,000 (average per year); includes \$16,520,000 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 ~~an in~~ significant number of small entities potentially affected by the rule ~~may experience an impact and~~ 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

**Commented [EO 12866268]:** How does EPA define "insignificant"?

**Commented [EPA269R268]:** We have edited the sentence for clarity.

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 notice, *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

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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<sub>2.5</sub>-related benefits, and CO<sub>2</sub>- related benefits from this final rule will further improve children’s health. Additionally, the ozone and PM<sub>2.5</sub> 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<sub>2.5</sub> 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.

**Commented [EO 12866270]:** Does implementation of the IRA affect the degree to which this rule will affect retail electricity prices and generation relative to the baseline?

**Commented [EPA271R270]:** EPA estimates the impact of the IRA on generation relative to the baseline in Appendix 4A, but does not estimate the impact of the IRA on retail electricity prices.



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*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 VIII of this notice. *Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement* of this final rule 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<sub>2.5</sub> exposures. Baseline ozone and PM<sub>2.5</sub> exposure analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less educated, and children may

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experience disproportionately higher ozone and PM<sub>2.5</sub> 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<sub>2.5</sub> 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<sub>2.5</sub> 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<sub>2.5</sub> 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 notice.

#### *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~~This~~ ~~is a~~ “major rule” as defined 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).<sup>445</sup>

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 [on its face](#) 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

<sup>445</sup> 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. Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

**Commented [Round 2272]:** 3/9/2023: We would suggest adding to the discussion of venue under section 307(b)(1) that EPA's determinations regarding the nature of ozone pollution, which can be transported thousands of miles from the source, and the interwoven and overlapping linkages between upwind and downwind states makes it particularly appropriate for EPA to make a finding of nationwide scope or effect in promulgating this action. The draft references the “interdependent nature of interstate pollutant transport” but that appears in the “nationally applicable” statement, rather than the “nationwide scope and effect” alternative determination, and in general EPA could take the opportunity to provide a little more illustrative color here, since this is an issue with a lot of significance for both this rule and the underlying state SIP disapprovals.

**Commented [EPA273R272]:** We believe the current venue discussion is adequate. We note that there is further discussion of venue in the RTC 1.10. The current language refers to the scope of linkages over the geography of the rule, which captures the point regarding great distances. This can be further fleshed out in briefing as needed by reference to other existing parts of the record.

**Commented [EO 12866274]:** Seems unnecessary

**Commented [EPA275R274]:** Deleted

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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.<sup>446</sup>

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

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<sup>446</sup> 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.

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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 **[INSERT 60 DAYS FROM DATE OF PUBLICATION OF FINAL ACTION IN FEDERAL REGISTER]**.

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”).

#### **List of Subjects**

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*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, Incorporation by reference, 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<sub>x</sub>), except” and adding in its place “(NO<sub>x</sub>) for sources meeting the applicability criteria set forth in that subpart, except”;

b. In paragraph (a)(3) introductory text, removing “(a)(2)(i) or (ii)” and adding in its place “(a)(2)”, and 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 those subparts, except”;

q. Redesignating paragraphs (b)(2)(i) and (ii) as paragraphs (b)(2)(i)(A) and (B), respectively, redesignating paragraphs (b)(2)(iii) and (iv) as paragraphs (b)(2)(ii)(A) and (B), respectively, and redesignating 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, removing “or (ii)”, and 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), removing “§ 97.1011(a)” and adding in its place “§ 97.1011(a)(1)”, and 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), removing “§ 97.1011(a)” and adding in its place “§ 97.1011(a)(1)”, and 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 (b)(14)(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 the newly redesignated paragraph, 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)**

<b>Year of the control period for which CSAPR NO<sub>x</sub> Annual allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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)**

<b>Year of the control period for which CSAPR NO<sub>x</sub> Annual allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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<sub>x</sub> 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<sub>x</sub> 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 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 (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<sub>x</sub> 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<sub>x</sub> 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

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Initiated 20230131

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 [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** and in each subsequent year: Minnesota, Nevada, and Utah.

\* \* \* \* \*

(4) *Abbreviated SIP revisions replacing certain provisions of the federal CSAPR NO<sub>x</sub> 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)**

<b>Year of the control period for which CSAPR NO<sub>x</sub> Ozone Season Group 1 allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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<sub>x</sub> 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<sub>x</sub> 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)**

<b>Year of the control period for which CSAPR NO<sub>x</sub> Ozone Season Group 1 allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 units and

the amount of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) \* \* \*

**Table 5 to Paragraph (b)(8)(iii)(B)**

<b>Year of the control period for which CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) \* \* \*

**Table 6 to Paragraph (b)(9)(iii)(B)**

<b>Year of the control period for which CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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 these sections 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 units and the amount of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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;

(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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 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 these sections, and further 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 after the Administrator’s approval of the SIP revision, 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<sub>x</sub> ozone season emissions; satisfaction of NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 1 allowances under subpartBBBBB of part 97 of this chapter, or allocations of CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter, or allocations of CSAPR NO<sub>x</sub> 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 subpartBBBBB 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<sub>x</sub> Ozone Season Group 1 allowances and CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 1 allowances and CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 1 allowances allocated for specified control periods to different amounts of CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances or CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances and the conversion of unused CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances allocated for specified control periods to different amounts of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances); and

(C) The provisions of § 97.811(d) and (e) of this chapter (concerning the recall of CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances equivalent in quantity and usability to all CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 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<sub>2</sub>), except” and adding in its place “(SO<sub>2</sub>) for sources meeting the applicability criteria set forth in those subparts, 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, removing “(c)(1) or (2)” and adding in its place “(c)”, and 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)**

<b>Year of the control period for which CSAPR SO<sub>2</sub> Group 1 allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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) \* \* \*

(i) \* \* \*

(ii) \* \* \*

**Table 2 to Paragraph (f)(1)(ii)**

<b>Year of the control period for which CSAPR SO<sub>2</sub> Group 1 allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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)**

<b>Year of the control period for which CSAPR SO<sub>2</sub> Group 2 allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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)**

<b>Year of the control period for which CSAPR SO<sub>2</sub> Group 2 allowances are allocated or auctioned</b>	<b>Deadline for submission of allocations or auction results to the Administrator</b>
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<sub>2</sub> 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<sub>2</sub> Group 1 allowances under subpart CCCCC of part 97 of this chapter, or allocations of CSAPR SO<sub>2</sub> 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<sub>2</sub> Group 1 allowances and CSAPR SO<sub>2</sub> 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<sub>2</sub> Group 1 allowances and CSAPR SO<sub>2</sub> Group 2 allowances between certain Allowance Management System accounts under common control).

(ii) [Reserved]

\* \* \* \* \*

4. Add §§ 52.40 through 52.46 to read as follows:

Sec.

\* \* \* \* \*

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?

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?

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?

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?

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?

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, and Pulp, Paper, and Paperboard Mills Industries?

52.46 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from Municipal Waste Combustors?

\* \* \* \* \*

§ 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 are defined as follows and in § 52.40, § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, and § 52.46.

*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 [THE EFFECTIVE DATE OF FINAL RULE].

*New Affected Unit* means any affected unit for which construction commenced on or after [THE EFFECTIVE DATE OF FINAL RULE].

*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 QA/QC requirements 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<sub>x</sub> 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<sub>x</sub> 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 § 52.40, § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 of this part 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 § 52.40, § 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).

(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).

(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) 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) 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 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 in writing to 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 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 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) 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 (d)(2). The decision to grant an extension will be in writing 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 written notification to the owner or operator of an affected unit who has requested a compliance extension under this paragraph 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 written notification, 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) that the submitted request is complete.

(9) Before denying any request for an extension of compliance, the Administrator will notify 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 in writing, 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 in writing 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), 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 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 [365 DAYS AFTER THE EFFECTIVE DATE OF FINAL RULE], 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<sub>x</sub> 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 **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]** 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 NOx emissions, such as operational standards or work practice standards.

(iii) Calculations of the NOx emissions reduction to be achieved through implementation of the proposed case-by-case emissions limit and any additional proposed measures, the difference between this NOx emissions reduction level and the NOx 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 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 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 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 in writing and publicly available, and will identify each affected unit covered by the case-by-case emissions limit.

(5) The Administrator will provide written notification to the owner or operator of an affected unit who has requested a case-by-case emissions limit under this paragraph 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 written notification, 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 written notification pursuant to paragraph(e)(5) that the submitted request is complete.

(7) Before denying any request for a case-by-case emissions limit, the Administrator will notify 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 in writing, 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 in writing 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 (e)(9)(ii), 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 § 52.40, § 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 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) *Compliance and Emissions Data Reporting Interface (CEDRI) Reporting requirements.*

(1) You shall submit the results of the performance test following the procedures specified in paragraphs (g)(1)(i) through (iii):

(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/>).

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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) *Confidential business information (CBI).*

(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 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 sh 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 OAQPS CBI Office at the email address [oaqpscbi@epa.gov](mailto:oaqpscbi@epa.gov),

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and as described above, 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 [oaqpsbi@epa.gov](mailto:oaqpsbi@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 herein shall have the meaning given to them in the Act and in subpart A of part 60.

*Affected unit* means an engine meeting the applicability criteria of this section.

*Cap* means the total amount of NO<sub>x</sub> 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<sub>x</sub> 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 that meets all of the criteria in paragraphs (1) and (2) of this definition. All emergency stationary RICE must comply with the requirements specified in paragraph (b)(1) 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.

(1) 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.

(2) The stationary RICE is operated under limited circumstances for purposes other than those identified in paragraph (1) of this definition, as specified in paragraph (b)(1).

*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<sub>2</sub> 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, excluding natural gas production facilities and natural gas processing plants, and including:

- (1) The compressor and pipeline network used for intrastate or interstate transportation of the natural gas; and
- (2) The compressor and pipeline network used to transport the natural gas from natural gas 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.

*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<sub>x</sub>) (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 ~~non-emergency-engine,~~ other than an emergency engine, with a nameplate rating of 1000 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 (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 (1)(i) through (iii), is prohibited. If you do not operate the RICE according to the requirements in paragraphs (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 (1)(iii) of this section counts as part of the 100 hours per calendar year allowed by paragraph (1)(ii). 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 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 (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 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). Any such request shall be submitted to the Administrator on or before October 1<sup>st</sup> of the year prior to each emissions averaging year. The Administrator will approve a proposed Facility-Wide Averaging Plan submitted under this paragraph if the Administrator determines that the proposed Facility-Wide Averaging Plan meets the requirements of this paragraph, 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) 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 NOx emissions control technology and the date of installation, and a description of any NOx 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), 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). You will be in compliance with the cap if the sum of NOx 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 the equation provided in this paragraph. 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.

$$Cap \text{ (tons per day)} = 907,184.74 \times \sum_{i=1}^N (R_{li} \times DC \times H_i)$$

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.

$R_{i1}$  = the emissions limit for each affected unit from paragraph (c) (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).

(4) Violations. 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<sub>x</sub> continuous emissions monitoring system (CEMS) that monitors NO<sub>x</sub> 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<sub>x</sub> emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO<sub>x</sub> emissions and either oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>).

(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<sub>x</sub> 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<sub>x</sub> 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, Method 7A of 40 CFR part 60, 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) Performance Testing Requirements: (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<sub>x</sub> 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<sub>x</sub> 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 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 of 40 CFR part 60, appendix A, any alternative test method approved by the EPA as of [INSERT DATE OF PUBLICATION IN THE *FEDERAL REGISTER*] 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-](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 NOx emissions limit in paragraph (c), 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 or 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 so long as you record and report your hours of operation during the ozone season in accordance with paragraphs (f) and (g).

(f) *Recordkeeping requirements.* (1) If you are the owner or operator of an affected unit, you

must keep records of:

- (i) Performance tests conducted pursuant to paragraph (e)(2), including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.
- (ii) Catalyst monitoring required by paragraph (e)(3), 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.
- (iii) Parameters monitored pursuant to the facility’s site-specific parametric monitoring plan.
- (iv) Hours of operation on a daily basis.
- (v) Tuning, adjustments, or other combustion process adjustments and the date of the adjustment(s).
- (vi) For any Facility-Wide Averaging Plan approved by the Administrator under paragraph (d), daily calculations of total NO<sub>x</sub> emissions to demonstrate compliance with the cap during the ozone season. You must use the equation in this paragraph to calculate total NO<sub>x</sub> 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.

$$\sum_{i=1}^N (R_{ai} \times DC \times H_{ai}) \leq \text{Cap (tons per day)}$$

$$\sum_{i=1}^N (R_{ai} \times DC \times H_{ai}) \leq \text{Cap (tons per day)}$$

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 30<sup>th</sup> 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). 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) or a Facility-Wide Averaging Plan under paragraph(d);
- (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);
- (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) or a Facility-Wide Averaging Plan under paragraph (d), 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?*

(1) (a) *Definitions.* All terms not defined herein shall have the meaning given to them in the Act and in subpart A of part 60.

*Affected unit* means a cement kiln meeting the applicability criteria of this section.

*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.

*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.

*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<sub>x</sub> on or after [EFFECTIVE DATE OF FINAL RULE] 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<sub>x</sub> on [THE EFFECTIVE DATE OF FINAL RULE] 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<sub>x</sub>.

(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 [INSERT DATE OF PUBLICATION IN THE *FEDERAL REGISTER*] 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<sub>x</sub> 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 6 of 40 CFR 60.64(c)(1), shown below:

$$E_{30D} = k \left( \frac{\sum_{i=1}^N C_i Q_i}{P} \right)$$



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SAN 8670 ~~EO 12866~~ \_ Good Neighbor Plan ~~2060 AV51~~ \_ Final \_ Preamble ~~20230207~~ EO 12866  
Initiated 20230131

$$E_{30D} = k \left( \frac{\sum_{i=1}^n C_i Q_i}{P} \right)$$

Where:

$E_{30D}$  = 30 kiln operating day average emissions rate of NO<sub>x</sub>, in lbs/ton of clinker.

$C_i$  = Concentration of NO<sub>x</sub> for hour  $i$ , in ppm.

$Q_i$  = Volumetric flow rate of effluent gas for hour  $i$ , where

$C_i$  and  $Q_i$  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<sub>x</sub> emissions measured, in tons.

$k$  = Conversion factor,  $1.194 \times 10^{-7}$  for NO<sub>x</sub>, 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<sub>x</sub> continuous emissions monitoring system (CEMS) that monitors NO<sub>x</sub> 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<sub>x</sub> emissions:

- (i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO<sub>x</sub> emissions and either oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>).
- (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<sub>x</sub> 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<sub>x</sub> 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, Method 7A of 40 CFR part 60, 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<sub>x</sub> 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 (d)(3)(v).

(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<sub>x</sub> 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  $\pm 5$  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<sub>x</sub> 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) and semi-annual title V monitoring reports to the

relevant permitting authority.

(e) *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<sub>x</sub> emissions rates measured or predicted;

(iii) The 30-day average NO<sub>x</sub> emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO<sub>x</sub> emissions rates for the preceding 30 operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO<sub>x</sub> emissions rates are in excess of the applicable site-specific NO<sub>x</sub> 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;

(viii) 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 of 40 CFR part 60;

(C) Results of daily CEMS drift tests and quarterly accuracy assessments as required under

Procedure 1 of 40 CFR part 60, appendix F; and

(ix) Operating parameters required under paragraph (d) to demonstrate compliance during the ozone season.

(x) Each fuel type, usage, and heat content.

(xi) 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<sub>x</sub> emissions rate that exceeds the applicable emissions limit established under paragraph (c). 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 30<sup>th</sup> 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), including record of CEMS data or operating parameters required by paragraph (d) to demonstrate continuous compliance the applicable emissions limits

under paragraph (c).

(g) *Initial Notification Requirements for Existing Affected Units.* (1) The requirements of this paragraph 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 [THE EFFECTIVE DATE OF FINAL RULE] shall notify the Administrator in writing that the unit is subject to this section. The notification, which shall be submitted not later than [120 DAYS AFTER THE EFFECTIVE DATE OF FINAL RULE]], 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 herein shall have the meaning given to them in the Act and in subpart A of part 60.

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*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 NOx 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 NOx.

*Low-NOx technology* means any post-combustion NOx control technology capable of reducing NOx 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 – to temperatures at which it will be suitable for deformation and further processing.

(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 NOx on or after [EFFECTIVE DATE OF FINAL RULE], does not have low-NOx 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 NOx on [THE

EFFECTIVE DATE OF FINAL RULE] 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<sub>x</sub>.

(c) *Emissions Control Requirements.* If you are the owner or operator of an affected unit without low-NO<sub>x</sub> burners already installed, you must install and operate low-NO<sub>x</sub> burners or equivalent alternative low-NO<sub>x</sub> technology designed to achieve at least a 40% reduction from baseline NO<sub>x</sub> emissions in accordance with the work plan established pursuant to paragraph (d). 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 [365 DAYS AFTER THE EFFECTIVE DATE OF FINAL RULE]. 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<sub>x</sub> burner or alternative low NO<sub>x</sub> 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 the effective date of this rule 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 (d)(3).

(2) The owner or operator of an affected unit shall design each low-NO<sub>x</sub> burner or alternative



low-NO<sub>x</sub> technology identified in the work plan to achieve NO<sub>x</sub> emission reductions by a minimum of 40% from baseline emission levels measured during performance testing that meets the criteria set forth in paragraph (d)(1), or during pre-installation testing as described in paragraph (d)(3) of this section. Each low-NO<sub>x</sub> burner or alternative low-NO<sub>x</sub> 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 ~~review~~-action on work plans:

(i) The Administrator will provide written 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 written notification, 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 (i) that the submitted work plan is complete.

(iii) Before disapproving a work plan, the Administrator will notify the owner or operator in writing 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 in writing 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 (5)(iii)(B), 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)-(3) of this section, or if the owner or operator of an affected unit fails to submit a work plan by [365 DAYS AFTER THE EFFECTIVE DATE OF FINAL RULE], 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 [INSERT DATE OF PUBLICATION IN THE *FEDERAL REGISTER*] 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<sub>x</sub> continuous emissions monitoring system (CEMS) that monitors NO<sub>x</sub> 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<sub>x</sub> emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO<sub>x</sub> emissions and either oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>).

(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<sub>x</sub> 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<sub>x</sub> 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, Method 7A of 40 CFR part 60, 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<sub>x</sub> 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 (d)(3)(v).

(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<sub>x</sub> 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) and semi-annual title V monitoring reports to the relevant permitting authority.

(f) *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<sub>x</sub> emissions rates measured or predicted;

(iii) The 30-day average NO<sub>x</sub> emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO<sub>x</sub> emissions rates for the preceding 30 operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO<sub>x</sub> emissions rates are in excess of the applicable site-specific NO<sub>x</sub> 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;

(viii) 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 of 40 CFR part 60;

(C) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F; and

(ix) Operating parameters required under paragraph (d) to demonstrate compliance during the ozone season.

(x) 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, 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<sub>x</sub> emissions rate that exceeds the applicable emissions limit established under paragraphs (c) and (d). 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 30<sup>th</sup> 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 (e), 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).

(5) 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<sub>x</sub> emissions rate, as determined under paragraphs (c) and (d) of this section, that exceeds the applicable emissions limit established pursuant to 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 consistent with the requirements of § 52.40(g).

(g) *Initial Notification Requirements for Existing Affected Units.* (1) The requirements of this paragraph 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<sub>x</sub> as of [THE EFFECTIVE DATE OF FINAL RULE] shall notify the Administrator in writing that the unit is subject to this section. The notification, which shall be submitted not later than [120 DAYS AFTER THE EFFECTIVE DATE OF FINAL RULE]], 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 herein shall have the meaning given to them in the Act and in subpart A of part 60.

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*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<sub>2</sub>O (e.g., Na<sub>2</sub>O and K<sub>2</sub>O), 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 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:



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50 to 60 percent silicon dioxide, 18 to 35 percent lead oxides, 5 to 20 percent total R<sub>2</sub>O (e.g., Na<sub>2</sub>O and K<sub>2</sub>O), 0 to 8 percent total R<sub>2</sub>O<sub>3</sub> (e.g., Al<sub>2</sub>O<sub>3</sub>), 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 §§ 52.44(d), 52.44(e), and 55.44(f), as applicable.

~~Operating day means a 24-hour period beginning at 12:00 midnight during which the furnace produces glass at any time.~~

*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<sub>2</sub>O (e.g., Na<sub>2</sub>O and K<sub>2</sub>O), 8 to 20 percent total RO but not to include any PbO (e.g., CaO, and MgO), 0 to 8 percent total R<sub>2</sub>O<sub>3</sub> (e.g., Al<sub>2</sub>O<sub>3</sub>), 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 fiber glass insulation, and other products listed in SIC 3296.

(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<sub>x</sub> on or after [EFFECTIVE DATE OF FINAL RULE] 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<sub>x</sub> on [THE EFFECTIVE DATE OF FINAL RULE] 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<sub>x</sub>.

(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) 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), 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), (e), and (f), 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 in writing to the Administrator, 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 § 52.44(d)(2)(i) and § 52.44(d)(2)(ii).

(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 in writing 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 NOx emissions during idling may not exceed the amount calculated using the following equation: Pounds per day emissions limit of NOx = (Applicable NOx emissions limit specified in paragraph (c) expressed in pounds per ton of glass produced) x (Furnace permitted production capacity in tons of glass produced per day).

(3) To demonstrate compliance with the alternative daily NOx emissions limit identified in paragraph (f)(2) during periods of idling, the owners or operators of an affected unit shall maintain records consistent with paragraph (h)(3).

(g) *Testing and Monitoring Requirements.* (1) If you own or operate an affected unit subject to the NOx 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, any alternative test method approved by the EPA as of **[INSERT DATE**

**OF PUBLICATION IN THE FEDERAL REGISTER]** 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-~~operating~~ day rolling average emissions rate of NO<sub>x</sub> 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-~~operating~~ 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<sub>x</sub> emissions limits under paragraph (c)(1) of this section and are operating a NO<sub>x</sub> CEMS that monitors NO<sub>x</sub> 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<sub>x</sub> emissions:

- (i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO<sub>x</sub> emissions and either oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>).
- (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<sub>x</sub> 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<sub>x</sub> 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, Method 7A of 40 CFR part 60, 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<sub>x</sub> 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 (g)(3)(iv).

(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<sub>x</sub> 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<sub>x</sub> 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) 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) or shutdown under paragraph (e) in lieu of the applicable emissions limit under paragraph (c), 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).

(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<sub>x</sub> emissions rates measured or predicted;

(iii) The 30-day average NO<sub>x</sub> emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO<sub>x</sub> emissions rates for the preceding 30 operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO<sub>x</sub> emissions rates are in excess of the applicable site-specific NO<sub>x</sub> 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 of 40 CFR part 60;

(C) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F; and

(viii) Operating parameters required under paragraph (g) to demonstrate compliance during the ozone season.

(ix) Each fuel type, usage, and heat content.

(x) 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), 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<sub>x</sub> emissions in pounds per day for purposes of determining compliance with the applicable

emissions limit for idling periods under paragraph (f)(2). 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<sub>x</sub> 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 30<sup>th</sup> 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), including record of CEMS data or operating parameters to demonstrate continuous compliance the applicable emissions limits under paragraphs (c).

(j) *Initial Notification Requirements for Existing Affected Units.* (1) The requirements of this paragraph 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 [THE EFFECTIVE DATE OF FINAL RULE] shall notify the Administrator in writing that the unit is subject to this section. The notification, which shall be submitted not later than [120 DAYS AFTER THE EFFECTIVE DATE OF FINAL RULE], 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 herein 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 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 60.41b.

*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, 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 (2) below.

(2) Low-use exemption: If you are the owner or operator of a boiler meeting the applicability criteria of paragraph (b)(1) 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.

(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<sub>x</sub>/mmBtu;

(2) Residual oil-fired industrial boilers: 0.20 lbs NO<sub>x</sub>/mmBtu;

(3) Distillate oil-fired industrial boilers: 0.12 lbs NO<sub>x</sub>/mmBtu;

(4) Natural gas-fired industrial boilers: 0.08 lbs NO<sub>x</sub>/mmBtu; and

(5) Boilers using combinations of fuels listed in (c)(1), (2), (3), and (4): such units shall comply with a NO<sub>x</sub> 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<sub>x</sub> specified by EPA Test Method 7E – Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure), as described at 40 CFR part 60, Appendix A-4, to determine compliance with the emissions limits for NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions and either oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>), 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<sub>x</sub>

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 shall during calibration checks and zero and span adjustments.

(iii) You shall express the 1-hour average NO<sub>x</sub> emissions rates measured by the CEMS in terms of lbs/mmBtu heat input and shall be used to calculate the average emissions rates under 40 CFR § 52.45(c).

(iv) Following the date on which the initial compliance test is completed, you shall determine compliance with the applicable NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> for affected units combusting coal and span value of 500 ppm NO<sub>x</sub> for units combusting oil or gas. As an alternative to meeting these span values, you may elect to use the NO<sub>x</sub> 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<sub>x</sub> 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, Method 7A of 40 CFR part 60, 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<sub>x</sub> until after the initial performance test has been conducted. If you demonstrate during the performance test that emissions of NO<sub>x</sub> 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<sub>x</sub>. 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<sub>x</sub> 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.

(e) If you are the owner or operator of an affected unit with a heat input capacity less than 250 mmBTU/hr, you ~~are~~ must monitor NO<sub>x</sub> emission via the requirements of section (e)(1) or you must monitor NO<sub>x</sub> 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<sub>x</sub> emission standards under § 52.45(c) using Method 7, 7A, or 7E of appendix A of part 60, Method 320 of appendix A of part 63, or other approved reference methods.

(ii) You must conduct annual performance tests once per calendar year to demonstrate compliance with the NO<sub>x</sub> emission standards under § 52.45(c) 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 of part 60, Method 320 of appendix A of 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<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub> level).

(B) You shall include the data and information used to identify the relationship between NO<sub>x</sub> 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.

(iv) 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<sub>x</sub> emissions rates (expressed as lbs NO<sub>2</sub>/mmBtu heat input) measured or predicted;

(iii) The 30-day average NO<sub>x</sub> emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO<sub>x</sub> 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<sub>x</sub> emissions rates are in excess of the applicable NO<sub>x</sub> 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 of 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<sub>x</sub> emissions rate, as determined under paragraph (e)(3)(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<sub>x</sub> 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)(2) 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 30<sup>th</sup> 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 herein 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:

(1) 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.

(2) 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:

(i) 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;

(ii) 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

(iii) The combustor water system, which starts at the feed water pump and ends at the piping exiting the steam drum or superheater.

(3) 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) .

*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~~ ~~meeting~~ 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<sub>x</sub> 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<sub>x</sub> 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 installed, evaluate, and operate the 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);

(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) The fuel factor equation in Method 3B shall be used to determine the relationship between oxygen and carbon dioxide at a sampling location. Method 3, 3A, or 3B, or as an alternative ASME PTC-19-10-1981 - part10, as applicable, shall be used to determine the oxygen concentration at the same location as the carbon dioxide monitor;

(B) Samples shall be taken for at least 30 minutes in each hour;

(C) Each sample shall represent a 1-hour average;

(D) A minimum of three runs shall be performed;

(E) This relationship may be reestablished during performance compliance tests; and

(vii) 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<sub>x</sub> emission limits in paragraph

(c):

(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<sub>x</sub> CEMS according to Performance Specification 2 in 40 CFR part 60, Appendix B and shall meet the following the procedures and methods:

(A) During each relative accuracy test run of the CEMS, nitrogen oxides and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30- to 60-minute period) by both the following continuous emissions monitors and the test methods:

(1) For nitrogen oxides, EPA Reference Method 7, 7A, 7C, 7D, or 7E shall be used; and

(2) For oxygen (or carbon dioxide), EPA Reference Method 3, 3A, or 3B, or as an alternative ASME PTC-19-10-1981 – part10, as applicable, shall be used.

(B) The span value of the CEMS shall be 125 percent of the maximum estimated hourly potential NO<sub>x</sub> emissions of the municipal waste combustor unit;

(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<sub>x</sub> 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 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 determine compliance EPA Reference Method 19, section 4.1 for determining the daily arithmetic average NO<sub>x</sub> emissions concentration.

(A) You may request that compliance with the NO<sub>x</sub> 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 (1)(vi) of this section.

(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<sub>x</sub> 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)(3)(iv) are not met; and

(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) by following the requirements below:

(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<sub>x</sub> mass loading emissions limitation for periods of startup and shutdown by calculating the 24-hour average of all hourly average NO<sub>x</sub> 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.

(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 (4)(i)(A) and (4)(i)(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;

(e) *Recordkeeping requirements.* (1) 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).

(i) The calendar date of each record.

(ii) The emissions concentrations and parameters measured using continuous monitoring systems.

(A) All 1-hour average NO<sub>x</sub> emissions concentrations.

(B) The average concentrations and percent reductions, as applicable, including all 24-hour daily arithmetic average NO<sub>x</sub> emissions concentrations.

(iii) Identification of the calendar dates and times (hours) for which valid hourly NO<sub>x</sub> emissions, including reasons for not obtaining the data and a description of corrective actions

taken.

(iv) Identification of each occurrence that NO<sub>x</sub> 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.

(v) The results of daily drift tests and quarterly accuracy determinations for CEMS, as required under 40 CFR part 60, Appendix F, procedure 1.

(vi) The following records:

(A) 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 § 60.54b(a) including the dates of initial and renewal certifications and documentation of current certification;

(B) 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 § 60.54b(b) including the dates of initial and renewal certifications and documentation of current certification;

(C) 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 § 60.54b(d) including documentation of training completion; and

(D) Records of when a certified operator is temporarily off site. Include two main items:

(1) 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.

(2) 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:

(i) Time of day that all certified persons are off site.

(ii) The conditions that cause those people to be off site.

(iii) 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.

(iv) Copies of the written 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.

(vii) Records showing the names of persons who have completed a review of the operating manual as required by § 60.54b(f) including the date of the initial review and subsequent annual reviews.

(viii) Records of steps taken to minimize emissions during startup and shutdown as required by paragraph (d)(5).

(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 shall submit an annual report in

PDF format to the EPA by January 30<sup>th</sup> 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), including CEMS data to demonstrate compliance with the applicable emissions limits under paragraph (c).

**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<sub>x</sub> 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



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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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances or CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO<sub>x</sub> 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), removing “2017 and each subsequent year.” and adding in its place “2017 through 2022.”, and 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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:

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- a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);
- b. In newly redesignated paragraph (a)(2), removing “2017 and each subsequent year.” and adding in its place “2017 through 2022.”, and 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances or CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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), removing “2017 and each subsequent year.” and adding in its place “2017 through 2022.”, and removing the second and third sentences;
- c. Revising newly redesignated paragraph (a)(3); and
- c. 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<sub>x</sub> 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

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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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO<sub>x</sub> 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), removing “2017 and each subsequent year.” and adding in its place “2017 through 2022.”, and 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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), removing “2017 and each subsequent year.” and adding in its place “2017 through 2022.”, and 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> mass emissions for common stack and multiple stack configurations.**

\* \* \* \* \*

(f) *Procedures for apportioning hourly NO<sub>x</sub> mass emission rate to the unit level.* If the owner or operator of a unit determining hourly NO<sub>x</sub> mass emission rate at a common stack under this section is subject to a State or federal NO<sub>x</sub> 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<sub>x</sub> 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 “Nox emissions” and adding in its place “NO<sub>x</sub> emissions”;
- c. Adding a paragraph 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 paragraph 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<sub>x</sub> 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 (h)(4)(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 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<sub>x</sub> mass emission rate at a common stack, apportioned hourly NO<sub>x</sub> 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 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<sub>x</sub> 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<sub>x</sub> emission rate (lb/mmBtu, rounded to the nearest thousandth) for each day of the reporting period;

(D) Daily NO<sub>x</sub> emissions (lbs) exceeding the applicable backstop daily NO<sub>x</sub> emission rate for each day of the reporting period;

(E) Cumulative NO<sub>x</sub> emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO<sub>x</sub> emission rate during the ozone season; and

(F) Cumulative NO<sub>x</sub> emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO<sub>x</sub> 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<sub>x</sub> emission rate (in lbs/mmBtu) shall do so by dividing daily or ozone season NO<sub>x</sub> 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<sub>x</sub> mass emissions at each unit” and adding in its place “hourly NO<sub>x</sub> 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.**

\* \* \* \* \*

5.3.3 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<sub>d</sub> = Total heat input for a unit for the day, mmBtu.

HI<sub>h</sub> = Heat input rate for the unit for hour “h” from Equation F-15, F-16, F-17, F-18, F-21a, or F-21b, mmBtu/hr.

t<sub>h</sub> = 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.

\* \* \* \* \*

8.1.2 If NO<sub>x</sub> 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<sub>x</sub> mass emissions:

(a) When hourly NO<sub>x</sub> mass emissions are reported in lb., use Eq. F-27 to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO<sub>x</sub> mass emissions in tons. \* \* \*

(b) When hourly NO<sub>x</sub> mass emission rate is reported in lb/hr, use Eq. F-27a to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO<sub>x</sub> mass emissions in tons.

\* \* \*

(c) To calculate daily NO<sub>x</sub> mass emissions for a unit in pounds, use Eq. F-27b.

$$M_{(NOX)_d} = \sum_{h=1}^{24} E_{(NOX)_h} t_h$$

(Eq. F-27b)

Where:

M<sub>(NOX)<sub>d</sub></sub> = NO<sub>x</sub> mass emissions for a unit for the day, pounds.

$E_{(NOX)h}$  = NO<sub>x</sub> 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<sub>x</sub> mass emission rate at a common stack shall apportion hourly NO<sub>x</sub> mass emissions rate to the units using the common stack based on the hourly heat input rate, using Equation F-28:

$$E_{(NOX)i} = E_{(NOX)CS} \left( \frac{t_{CS}}{t_i} \right) \left[ \frac{HI_i t_i}{\sum_{i=1}^n HI_i t_i} \right]$$

(Eq. F-28)

Where:

$E_{(NOX)i}$  = Apportioned NO<sub>x</sub> mass emission rate for the hour for unit “i”, lb/hr.

$E_{(NOX)CS}$  = NO<sub>x</sub> 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, 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.

\*\*\* E.O. 12866 Review – Draft – Do Not Cite, Quote, or Release During Review\*\*\*  
SAN 8670~~EO12866~~\_Good Neighbor Plan\_~~2060-AV51-Final-Preamble\_20230207\_EO 12866~~  
~~Initiated20230131~~

(ii) The calculation of an allocation of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances under § 97.1011 or § 97.1012 of this chapter.

(iii) The decision on the transfer of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances under § 97.1023 of this chapter.

(iv) The decision on the deduction of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> BUDGET TRADING PROGRAM, CAIR NO<sub>x</sub> AND SO<sub>2</sub> TRADING PROGRAMS, CSAPR NO<sub>x</sub> AND SO<sub>2</sub> TRADING PROGRAMS, AND TEXAS SO<sub>2</sub> 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<sub>x</sub> Annual Trading Program**

**§ 97.402 [Amended]**

36. Amend § 97.402 by:

- a. In the definition of “CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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”;

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 removing “set forth in” and adding in its place “established under”, and removing “State (or Indian” and adding in its place “State (and Indian”.

**Subpart BBBBBB—CSAPR NO<sub>x</sub> Ozone Season Group 1 Trading Program**

**§ 97.502 [Amended]**

40. Amend § 97.502 by:

a. In the definition of “CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowance”, adding “or (e)” after “§ 97.826(d)”, and adding “or less” after “one ton”;

d. In the definition of “CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program”, removing “(b)(2)(v), and” and adding in its place “(b)(2)(iii), 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), removing “set forth in” and adding in its place “established under”, and 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”;

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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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

recording of a given number of CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub> Group 1 Trading Program**

**§ 97.602 [Amended]**

44. Amend § 97.602 by:

- a. In the definition of “CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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”;

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 removing “set forth in” and adding in its place “established under”, and removing “State (or Indian” and adding in its place “State (and Indian”.

**Subpart DDDDD—CSAPR SO<sub>2</sub> Group 2 Trading Program**

48. Amend § 97.702 by:

a. In the definition of “alternate designated representative”, removing “or CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, then” and adding in its place “CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, or CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program, then”;

b. In the definition of “CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 Trading Program”; and

e. In the definition of “designated representative”, removing “or CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, then” and adding in its place “CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, or CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program, then”.

**§ 97.702 Definitions.**

\* \* \* \* \*

*CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program* means a multi-state NO<sub>x</sub> 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<sub>x</sub>.

\* \* \* \* \*

**§ 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 removing “set forth in” and adding in its place “established under”, and 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<sub>x</sub> Ozone Season Group 2 Trading Program, quarterly” and adding in its place “CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, or CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program, quarterly”.

**Subpart EEEEE—CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 source” and “base CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowance”, adding “or (e)” after “§ 97.826(d)”, and adding “or less” after “one ton”;
- h. In the definition of “CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances allocated for such control period to the group of one or more CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances purchased by an owner or operator of such CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 units in accordance with the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowance allocations.**

\* \* \* \* \*

(e) *Recall of CSAPR NO<sub>x</sub> 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 and paragraphs (e)(2) through (7) of this section shall apply with regard to each CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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.

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(ii)(A) The surrender requirement under paragraph (e)(2)(i) of this section corresponding to each CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowance described in paragraph (e)(1) of this section with regard to such source (whether recordation of such CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, 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<sub>x</sub> 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 **[INSERT DATE 75 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, the Administrator will deduct from the compliance account for each source described in paragraph (e)(1) of this section CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances allocated for such given control period and will then deduct CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances allocated for each successively earlier control period in sequence.



(C) When deducting CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances from any Allowance Management System accounts in which such CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowance under paragraph (e)(4)(i) of

this section. For purposes of this paragraph, each owner or operator of a source shall be deemed to be a person with an ownership interest in any CSAPR NO<sub>x</sub> Ozone Season Group 2 allowance held in that source's compliance account. The limitation established by this paragraph on the deductibility of certain CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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”;

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), removing “set forth in” and adding in its place “established under”, and 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<sub>x</sub> 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 **[INSERT DATE 105 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, the Administrator will temporarily suspend acceptance of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 the sum of all CSAPR NO<sub>x</sub> Ozone Season Group 2 allowances deducted from all such accounts under paragraph (e)(1)(i) of this section divided by 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.

(iii) The Administrator will allocate and record in each such account an amount of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances in that compliance account but instead will allocate and record the amount of CSAPR NO<sub>x</sub> 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 **[INSERT DATE 105 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, the Administrator may record such CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances but instead will allocate and record in such account an amount of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (e)(1)(ii) of this section.

#### **Subpart FFFFF—Texas SO<sub>2</sub> Trading Program**

60. Amend § 97.902 by:

a. In the definition of “alternate designated representative”, removing “Program or CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, then” and adding in its place “Program, CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, or CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program, then”;

b. In the definition of “CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 Trading Program”; and

d. In the definition of “designated representative”, removing “Program or CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, then” and adding in its place “Program, CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, or CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program, then”.

The addition reads as follows:

**§ 97.902 Definitions.**

\* \* \* \* \*

*CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program* means a multi-state NO<sub>x</sub> 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<sub>x</sub>.

\* \* \* \* \*

**§ 97.934 [Amended]**

61. In § 97.934, amend paragraph (d)(3) by removing “Program or CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, quarterly” and adding in its place “Program, CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, or CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program, quarterly”.

**Subpart GGGGG—CSAPR NO<sub>x</sub> 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<sub>2</sub> Group 1 Trading Program, then” and adding in its place “CSAPR SO<sub>2</sub> Group 1 Trading Program, or CSAPR SO<sub>2</sub> 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<sub>x</sub> emissions rate”;
- f. Removing the definitions for “base CSAPR NO<sub>x</sub> Ozone Season Group 3 source” and “base CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 1 Trading Program”;

m. In the definition of “CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowance”, adding “or (e)” after “§ 97.826(d)”, and adding “or less” after “one ton”;

o. In the definitions of “CSAPR NO<sub>x</sub> Ozone Season Group 3 allowance deduction” and “CSAPR NO<sub>x</sub> Ozone Season Group 3 emissions limitation”, adding “primary” before “emissions limitation”;

p. Adding in alphabetical order a definition for “CSAPR NO<sub>x</sub> Ozone Season Group 3 secondary emissions limitation”;

q. In the definition of “CSAPR NO<sub>x</sub> 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<sub>2</sub> Group 2 Trading Program”;

s. In the definition of “designated representative”, removing “or CSAPR SO<sub>2</sub> Group 1 Trading Program, then” and adding in its place “CSAPR SO<sub>2</sub> Group 1 Trading Program, or CSAPR SO<sub>2</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances to be initially credited, at no cost to the recipient, to:

- (1) A CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 unit qualifying for an initial credit, a credit in the amount of zero CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances, the CSAPR NO<sub>x</sub> Ozone Season Group 3 unit will be treated as being allocated an amount (*i.e.*, zero) of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances.

\* \* \* \* \*

*Backstop daily NO<sub>x</sub> emissions rate* means a NO<sub>x</sub> emissions rate used in the determination of the CSAPR NO<sub>x</sub> Ozone Season Group 3 primary emissions limitation for a CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances allocated for such control period to the group of one or more CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances purchased by an owner or operator of such CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 units in accordance with the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 trading budget;

(2) Provided that the allocations of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances for any control period taken into account for purposes of this definition shall exclude any CSAPR NO<sub>x</sub>

Ozone Season Group 3 allowances allocated for such control period under § 97.526(d) or § 97.826(d) or (e).

\* \* \* \* \*

*CSAPR NO<sub>x</sub> Ozone Season Group 1 Trading Program* means a multi-state NO<sub>x</sub> air pollution control and emission reduction program established in accordance with subpart BBBBBB 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<sub>x</sub>.

\* \* \* \* \*

*CSAPR NO<sub>x</sub> Ozone Season Group 3 secondary emissions limitation* means, for a CSAPR NO<sub>x</sub> 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<sub>x</sub> emissions calculated for the unit in accordance with § 97.1025(c)(2) for such control period.

\* \* \* \* \*

*CSAPR SO<sub>2</sub> Group 2 Trading Program* means a multi-state SO<sub>2</sub> 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<sub>2</sub>.

\* \* \* \* \*

*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<sub>x</sub> Ozone Season Group 3 Trading Program during such period.

\* \* \* \* \*

63. Amend § 97.1006 by:

- a. Revising paragraph (b)(2), the 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; ~~and~~
- f. Revising paragraph (c)(3); ~~and~~; ~~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<sub>x</sub> Ozone Season Group 3 allowances under §§ 97.1011 and 97.1012 and to determine compliance with the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 source and each CSAPR NO<sub>x</sub> Ozone Season Group 3 unit at the source shall hold, in the source's compliance account, CSAPR NO<sub>x</sub> 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<sub>x</sub> emissions for such control period from all CSAPR NO<sub>x</sub> Ozone Season Group 3 units at the source; plus

(B) Two times the excess, if any, of the sum, for all CSAPR NO<sub>x</sub> Ozone Season Group 3 units at the source and all calendar days of the control period, of any NO<sub>x</sub> emissions from such a unit on any calendar day of the control period exceeding the NO<sub>x</sub> 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<sub>x</sub> emissions rate applicable to the unit for that control period.

(ii) *Exceedances of primary emissions limitation.* If total NO<sub>x</sub> emissions during a control period in a given year from the CSAPR NO<sub>x</sub> Ozone Season Group 3 units at a CSAPR NO<sub>x</sub> Ozone Season Group 3 source are in excess of the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions during a control period in a given year from a CSAPR NO<sub>x</sub> Ozone Season Group 3 unit are in excess of the amount of a CSAPR NO<sub>x</sub> 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<sub>x</sub> emissions from all CSAPR NO<sub>x</sub> Ozone Season Group 3 units at CSAPR NO<sub>x</sub> 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<sub>x</sub> emissions exceed the sum, for such control period, of the State NO<sub>x</sub> 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<sub>x</sub> 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) **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 trading budgets, set-asides, and variability limits.**

(a) *State NO<sub>x</sub> Ozone Season Group 3 trading budgets.* (1)(i) The State NO<sub>x</sub> Ozone Season Group 3 trading budgets for allocations of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances for the control periods in 2021 through 2025 shall be as indicated in Table 1 to this paragraph, 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<sub>x</sub> Ozone Season Group 3 Trading Budgets by Control Period, 2021–2025 (tons)**

State	2021	2022	Portion of 2023 control period before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], before prorating	Portion of 2023 control period on and after [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], 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

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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<sub>x</sub> 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 **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** shown for the State in Table 1 to paragraph (a)(1)(i) of this section (or zero if Table 1 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 **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, 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 **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** 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 **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** through September 30, 2023, inclusive, and whose denominator is 153.

(2)(i) The State NOx 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, 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	<del>3,639</del> 3,409
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	<del>31,123</del> 31,170	<del>23,009</del> 23,127	<del>21,623</del> 21,490	<del>20,635</del> 20,502
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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 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<sub>x</sub> 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<sub>x</sub> Emission Rates for Dynamic Budget Calculations” posted at [www.regulations.gov](http://www.regulations.gov) in docket EPA-HQ-OAR-2021-0668, the NO<sub>x</sub> emissions rate used in the calculation for the control period shall be the NO<sub>x</sub> 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<sub>x</sub> 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:

(A) For a unit listed in the tables entitled “Dynamic Budget 2026 Template” and “Dynamic Budget 2027+ Template” posted at [www.regulations.gov](http://www.regulations.gov) with docket identification number EPA-HQ-OAR-2021-0668-~~XXXXX~~, the NO<sub>x</sub> emissions rate used in the calculation for the control period shall be the NO<sub>x</sub> emissions rate shown for the unit and control period in the tables.

(B) For a unit not listed in the tables referenced in paragraph (a)(4)(iii)(A) of this section, the NO<sub>x</sub> 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~~ 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 ~~simple cycle combustion turbine or 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<sub>x</sub> 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 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances for the control periods in 2021 and 2022 for each State with CSAPR NO<sub>x</sub> Ozone Season Group 3 trading budgets for such control periods shall be as indicated in Table 3 to this paragraph:

**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

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Virginia	185	161
West Virginia	266	261

(2) The new unit set-aside for allocations of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances for the control periods in 2021 and 2022 for each State with CSAPR NO<sub>x</sub> Ozone Season Group 3 trading budgets for such control periods shall be as indicated in Table 4 to this paragraph:

**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

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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 NOx 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.

**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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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, 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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.

**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	<del>277,262,840</del> <del>966,976</del>
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	<del>1,356,192,532</del> <del>357,814,072</del>	<del>1,320,040,162</del> <del>1,304,865,258</del>	<del>1,280,014,875</del> <del>264,839,971</del>
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<sub>x</sub> 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<sub>x</sub> 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), and (c)(1) and (5) to read as follows:

**§ 97.1011 CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances to the CSAPR NO<sub>x</sub> Ozone Season Group 3 units as follows:

(1) For each State and control period, the total amount of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances for which the Administrator will calculate default allocations shall be the remainder of the State NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances for each CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 of the 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 of the total heat input amounts identified for the unit under paragraph (b)(3)(i) of this section in mmBtu multiplied by a NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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 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<sub>x</sub> 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 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances to each CSAPR NO<sub>x</sub> 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 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 of data availability and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances to existing units.*

(1) For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 trading budget CSAPR NO<sub>x</sub> 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<sub>x</sub> 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-recording 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<sub>x</sub> Ozone Season Group 3 allowances to the new unit set-aside for 2021, 2022, or 2023 for the State from whose NO<sub>x</sub> Ozone Season Group 3 trading budget the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances were allocated.

(ii) If the non-recording 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<sub>x</sub> Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances to the new unit set-aside for such control period for the State from whose NO<sub>x</sub> Ozone Season Group 3 trading budget the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances were allocated.

(iii) If the non-recording 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<sub>x</sub> Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO<sub>x</sub> 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”;
- p. Adding paragraphs (b)(13) and (c).

The revisions and additions read as follows:

**§ 97.1012 CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances to the CSAPR NO<sub>x</sub> Ozone Season Group 3 units as follows:

(1) \* \* \*

(i) CSAPR NO<sub>x</sub> Ozone Season Group 3 units that are not allocated an amount of CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 units whose allocation of an amount of CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO<sub>x</sub> emissions as set forth

in § 97.1010(c) and will be allocated additional CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances.

(4)(i) The allocation to each CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances determined for all such CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO<sub>x</sub> 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<sub>x</sub>



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<sub>x</sub> Ozone Season Group 3 allowance allocation to each CSAPR NO<sub>x</sub> 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 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances to the CSAPR NO<sub>x</sub> Ozone Season Group 3 units as follows:

(1) The CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances will be allocated to CSAPR NO<sub>x</sub> Ozone Season Group 3 units that are not allocated an amount of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances for such control period in the applicable notice of data availability issued under § 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<sub>x</sub> Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO<sub>x</sub> emissions as set forth in § 97.1010(d) and will be allocated additional CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowance allocation to each CSAPR NO<sub>x</sub> 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 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances to new units.* (1)

For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances under § 97.1021.

(3) If the Administrator already recorded such CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances were recorded an amount of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances allocated for the same or a prior control period equal to the amount of such already recorded CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances. The authorized account representative shall ensure that there are sufficient CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances.

(5) With regard to any CSAPR NO<sub>x</sub> 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-recording 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 trading budget the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances were allocated.

(ii) If the non-recording 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<sub>x</sub> Ozone Season Group 3 allowances to the new unit set-aside for the control period in 2023 for the State from whose NO<sub>x</sub> Ozone Season Group 3 trading budget the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances were allocated.

(iii) If the non-recording 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<sub>x</sub> 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 “May 1 of each year thereafter, the” and adding in its place “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<sub>x</sub> Ozone Season Group 3 allowance allocations and auction results.**

\* \* \* \* \*

(b) By July 29, 2021, the Administrator will record in each CSAPR NO<sub>x</sub> Ozone Season Group 3 source’s compliance account the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances

allocated to the CSAPR NO<sub>x</sub> Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2022.

\* \* \* \* \*

(d) By **[INSERT DATE 90 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, the Administrator will record in each CSAPR NO<sub>x</sub> Ozone Season Group 3 source's compliance account the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances allocated to the CSAPR NO<sub>x</sub> Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2023.

(e) By **[INSERT DATE 90 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, the Administrator will record in each CSAPR NO<sub>x</sub> Ozone Season Group 3 source's compliance account the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances allocated to the CSAPR NO<sub>x</sub> 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 **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** 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<sub>x</sub> Ozone Season Group 3 source's compliance account the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances allocated to the CSAPR NO<sub>x</sub> Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

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Initiated 20230131

(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<sub>x</sub> Ozone Season Group 3 source's compliance account the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances allocated to the CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 source's compliance account the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances allocated to the CSAPR NO<sub>x</sub> Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

\* \* \* \* \*

(g) By **[INSERT DATE 90 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, the Administrator will record in each CSAPR NO<sub>x</sub> Ozone Season Group 3 source's compliance account the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances allocated to the CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 source's compliance account the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances allocated to the CSAPR NO<sub>x</sub> 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.



(i) By May 1, 2022 and May 1 of each year thereafter, the Administrator will record in each CSAPR NO<sub>x</sub> Ozone Season Group 3 source’s compliance account the CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances allocated to the CSAPR NO<sub>x</sub> 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.

\* \* \* \* \*

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<sub>x</sub> Ozone Season Group 3 primary emissions limitation; backstop daily NO<sub>x</sub> emissions rate.**

\* \* \* \* \*

(b) \* \* \*

(1) Until the amount of CSAPR NO<sub>x</sub> Ozone Season Group 3 allowances deducted equals the sum of:

(i) The number of tons of total NO<sub>x</sub> emissions from all CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 units at the source to which the backstop daily NO<sub>x</sub> emissions rate applies for the control period under paragraph (b)(3) of this section, of any amount by which a unit's NO<sub>x</sub> 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<sub>x</sub> emissions rate of 0.14 lb/mmBtu applies as follows:

(i) For each control period in 2024 through 2029, the backstop daily NO<sub>x</sub> emissions rate shall apply to each CSAPR NO<sub>x</sub> 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<sub>x</sub> emissions rate shall apply to each CSAPR NO<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 assurance provisions;  
CSAPR NO<sub>x</sub> Ozone Season Group 3 secondary emissions limitation.**

\* \* \* \* \*

(c) *CSAPR NO<sub>x</sub> Ozone Season Group 3 secondary emissions limitation.* (1) The owner or operator of a CSAPR NO<sub>x</sub> 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<sub>x</sub> 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 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<sub>x</sub> Ozone Season Group 3 units at CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 1 Trading Program, CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, or CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program.

(2) The amount of the emissions limitation applicable to a CSAPR NO<sub>x</sub> Ozone Season Group 3 unit for a control period under paragraph (c)(1) of this section, in tons of NO<sub>x</sub>, 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<sub>x</sub> emission rate of 0.10 lb/mmBtu or, if higher, the product of 1.25 times the lowest seasonal average NO<sub>x</sub> emission rate in lb/mmBtu achieved by the unit in any historical control period for which the unit was required to report NO<sub>x</sub> emissions and heat input data for all or portions of at least 367 operating hours under the CSAPR NO<sub>x</sub> Ozone Season Group 1 Trading Program, CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program, or CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program, where the unit's seasonal average NO<sub>x</sub> 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<sub>x</sub> 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;
- b. Revising paragraph (b);
- c. In paragraph (c), removing “set forth in” and adding in its place “established under”, and removing “State (or Indian” and adding in its place “State (and Indian”;
- d. Adding paragraph (d).

The revision and addition read as follows:

**§ 97.1026 Banking; bank recalibration.**

\* \* \* \* \*

(b) Any CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances issued for the control periods in previous years exceeding the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3 allowances determined under paragraph (d)(2)(i) of this section exceeds the CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> Ozone Season Group 3

allowances computed for such group, basing such shares on the respective quantities of CSAPR NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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)”.

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) **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, 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<sub>x</sub> mass emissions data or NO<sub>x</sub> emissions rate data according to 40 CFR part 75 to address other regulatory requirements; or

(iv) **[INSERT DATE 240 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** 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<sub>x</sub> mass emissions data or NO<sub>x</sub> 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<sub>2</sub> Group 1 Trading Program, quarterly” and adding in its place “CSAPR SO<sub>2</sub> Group 1 Trading Program, or CSAPR SO<sub>2</sub> Group 2 Trading Program, quarterly”.

The revision reads as follows:

**§ 97.1034 Recordkeeping and reporting.**

\* \* \* \* \*

(d) \* \* \*

(2) \* \* \*

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(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 **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** 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;

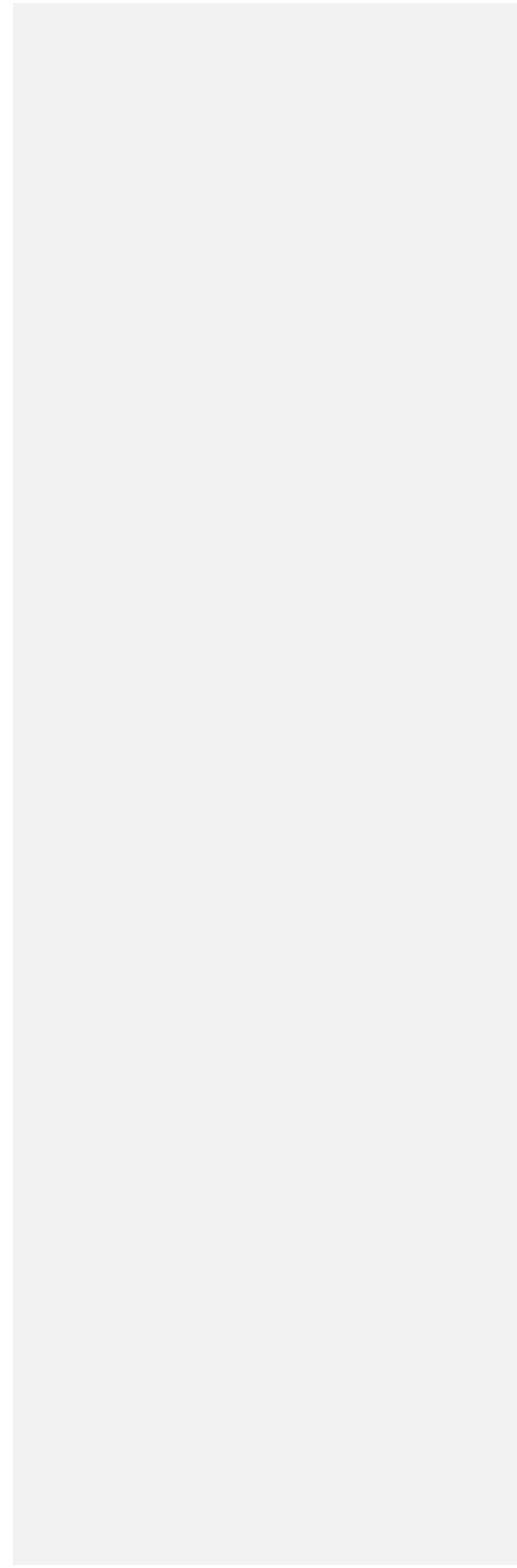
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# Regulatory Impact Analysis for the Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard



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EPA-452/R-23-001  
March 2023

Regulatory Impact Analysis for Final Federal Good Neighbor Plan Addressing Regional Ozone  
Transport for the 2015 Ozone National Ambient Air Quality Standard

U.S. Environmental Protection Agency  
Office of Air Quality Planning and Standards  
Health and Environmental Impacts Division  
Research Triangle Park, NC

*\*\*\* E.O. 12866 Review – Draft – Do Not Cite, Quote, or Release During Review\*\*\*  
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#### **CONTACT INFORMATION**

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## EXECUTIVE SUMMARY

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### Overview

This document presents the regulatory impact analysis (RIA) for the final rule, the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS). This RIA provides the EPA’s analysis of a variety of potential impacts (i.e., consequences) of the final rule and is used to inform the EPA and the public about these potential impacts. In the rule, the EPA promulgates implementation mechanisms to achieve enforceable emissions reductions required to eliminate ozone precursor emissions that significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in other states.<sup>1</sup> The initial phase of emissions reductions will begin in the 2023 ozone season with further emissions reductions being required in later years.

The EPA is promulgating new or revised FIPs for 23 states. For 22 states the FIPs include new NO<sub>x</sub> ozone season emission budgets for EGU sources, with implementation of these emission budgets beginning in the 2023 ozone season.<sup>2</sup> The EPA is expanding the Cross-State Air Pollution Rule (CSAPR) NO<sub>x</sub> Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs require electric generating units (EGUs) within the borders of the 22 states to participate in a revised version of the CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of 12 states currently participating in the Group 3 Trading Program under FIPs or SIPs remain in the program, with revised provisions beginning in the 2023 ozone season. The FIPs also require affected EGUs within the borders of seven states currently covered by the CSAPR NO<sub>x</sub> 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. Lastly, the EPA is issuing new FIPs for three

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<sup>1</sup> The 2015 ozone NAAQS is an 8-hour standard that was set at 70 parts per billion (ppb). See 80 FR 65291 (December 28, 2015).

<sup>2</sup> In 2023, the 22 states with EGU reduction requirements include AL, AR, IL, IN, KY, LA, MD, MI, MN, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, WV, and WI. There are no EGU reductions being required from California, which if included would make 23 states.

states not currently covered by any CSAPR NO<sub>x</sub> ozone season trading program (Minnesota, Nevada, and Utah).

For non-electric generating units (non-EGUs), the FIPs that EPA is promulgating for 20 states include new NO<sub>x</sub> emissions limitations, with initial compliance dates for these emissions limitations beginning in 2026.<sup>3</sup>

Consistent with OMB Circular A-4 and EPA’s *Guidelines for Preparing Economic Analyses* (2010), this RIA presents the benefits and costs of the final rule from 2023 through 2042. For the proposal RIA and this final RIA, we selected a 20-year analytical period because it is generally representative of and covers the lifetime of the capital equipment anticipated to be installed in response to the rule. Costs, benefits, and other impacts from compliance strategies are likely to occur beyond 2042. The estimated health benefits are expected to arise from reduced ozone and PM<sub>2.5</sub> concentrations, and the estimated climate benefits are from reduced greenhouse gas (GHG) emissions. The estimated costs for EGUs are the costs of installing and operating controls and the increased costs of producing electricity to comply with the revised version of the Group 3 trading program. The estimated costs for non-EGUs are the costs of installing and operating controls to meet the ozone season NO<sub>x</sub> emissions limitations. The estimated costs that the EPA reports for non-EGUs do not include monitoring, recordkeeping, reporting, or testing costs, which the EPA summarizes in Section X.B.2 of the final rule preamble and discusses in Chapter 4, Section 4.4 of the RIA below. Unquantified benefits and costs are described qualitatively. The RIA also provides estimates of other impacts of the final rule including its effect on retail electricity prices, fuel production for electricity generation, EGU-related employment, and environmental justice (EJ) impacts.

### ES.1 Identifying Needed Emissions Reductions and Regulatory Requirements

To reduce interstate emission transport under the authority provided in CAA section 110(a)(2)(D)(i)(I), the final rule further limits ozone season NO<sub>x</sub> emissions from EGUs and non-EGUs using the same framework used by the EPA in developing the CSAPR. The Interstate Transport Framework provides a 4-step process to address the requirements of the good neighbor

<sup>3</sup> In 2026, the 20 states with non-EGU reduction requirements include AR, CA, IL, IN, KY, LA, MD, MI, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, and WV.

**Commented [EO 128661]:** Please explain why the analytical period stops at 20 years. If costs and benefits are too uncertain to monetize after 2042, please characterize the likely magnitude and dynamics of net benefits after 2042: for example, if costs tend to be front-loaded, while undiscounted benefits like climate effects actually rise every year on a per ton basis, explain that net benefits would be likely to continue after 2042.

**Commented [EPA2R1]:** For the proposal RIA and this final RIA, we selected a 20-year analytical period because it is generally representative of and covers the lifetime of the capital equipment anticipated to be installed in response to the rule.

**Commented [EPA3R1]:** 3/10/2023: Suggest adding this explanation and a statement that EPA believes net benefits would continue after 2042.

**Commented [EPA4R1]:** Thank you. We added suggested text.

**Commented [EO 128665]:** Why does EPA not account for these costs?

**Commented [EPA6R5]:** The EPA received a few comments/estimates for monitoring, recordkeeping, reporting, or testing costs for non-EGUs sources; these estimates were not sufficient information to present these categories of costs.

The EPA will submit an information collection request (ICR) to OMB associated with the monitoring, calibrating, recordkeeping, reporting and testing activities required for non-EGU emissions units -- *ICR for the Final Rule, Federal Good Neighbor 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 X.B.2 of the final rule preamble. The ICR includes estimated monitoring, recordkeeping, reporting, and testing costs of approximately \$3.8 million ... [1]

**Commented [EPA7R5]:** 3/10/2023: It sounds like EPA already has a cost estimate for purposes of the ICR submission; why can't EPA use those estimates as an input to the total estimated compliance costs reported here? While we note that the costs are small relative to the overall ... [2]

**Commented [EPA8R5]:** The ICR for the non-EGU portion of the rule is submitted to OMB separately from the rule preamble, RIA, and technical support documents (rule package) that are part of the interagency review. As such ... [3]

**Commented [Round 39R5]:** 3/13: We don't understand why EPA is not willing to include cost estimates that it has already generated. The final costs are always subject to change during OMB review of the ICR. See added text to resolve this issue and move toward conclusion.

**Commented [EPA10R5]:** Thank you for the suggestion.

We accept the edit and clarified the suggested language.

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provision for ground-level ozone and fine particulate matter (PM<sub>2.5</sub>) NAAQS: (1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (2) determining which upwind states contribute to these identified problems in amounts sufficient to “link” them to the downwind air quality problems (i.e., here, an amount of contribution equal to or greater than 1 percent of the NAAQS); (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; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, implementing the necessary emissions reductions through enforceable measures. In this action, the EPA applies this 4-step Interstate Transport Framework for the Transport FIP for the 2015 ozone NAAQS.

For EGUs, in identifying levels of uniform control stringency the EPA assessed the same NO<sub>x</sub> emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available for EGUs: (1) fully operating existing SCR, including both optimizing NO<sub>x</sub> removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO<sub>x</sub> combustion controls; (3) fully operating existing SNCRs, including both optimizing NO<sub>x</sub> 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 (i.e., emission reductions anticipated to occur from generation shifting from higher to lower emitting units). The selected levels of uniform control stringency were represented by \$1,800 per ton of NO<sub>x</sub> (2016\$) in 2023 and \$11,000 per ton of NO<sub>x</sub> (2016\$) in 2026.<sup>4</sup>

Based on this uniform control stringency analysis, the rule establishes NO<sub>x</sub> emissions budgets requiring fossil fuel-fired EGUs in 22 states to participate in an allowance-based ozone season (May 1 through September 30) trading program beginning in 2023. The EGUs covered by the FIPs and subject to the budget are fossil-fired EGUs with >25-megawatt (MW) capacity. Any new fossil fuel-fired EGU serving a generator with a nameplate capacity exceeding 25 MW

<sup>4</sup> The EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD, in the docket (Docket ID No. EPA-HQ-OAR-2021-0688), describes how these costs per ton were chosen for the EGU stringency in this rule. Generation shifting is not included as a control strategy when establishing the budgets in the final rule. However, generation shifting is a control strategy that the EPA expects will be used for compliance. For additional discussion, please see Chapter 4.

**Commented [EO 1286611]:** How is EPA discussing the increase from \$1800/ton to \$11000/ton for NO<sub>x</sub> from EGUs? Other than noting the cost increase, we didn't see explanation of why this increase is reasonable. Would EPA point to such a discussion in the RIA or provide one if it isn't already provided?

**Commented [EPA12R11]:** The EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD referenced here details the rationale for stopping at the level of control stringency chosen, and the costs of these stringency levels.

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capacity that meets the applicability criteria and is deployed in any of the states covered by this rule’s EGU ozone-season NO<sub>x</sub> program would be subject to the same requirements as other covered EGUs. For details on the derivation of emissions budgets, please see Section V.C. of the final rule preamble.

In this rule, we introduce additional features to the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets over time and a backstop daily emission rate for most coal-fired units, along with an adjustment to the total size of the allowance bank, which is 21 percent of the sum of the state emissions budgets for the current control period until 2030 (at which point it declines to 10.5%), that were not included in previous CSAPR NO<sub>x</sub> ozone season trading programs. These enhancements will help maintain control stringency over time and improve emissions performance at individual units, offering an extra measure of assurance that existing pollution controls will be operated during the ozone season.

In this final action, the EPA is retaining the industries and many of the emissions unit types included in the proposal. At proposal, the EPA developed an analytical framework and applicability criteria to determine which industries and emissions unit types required NO<sub>x</sub> limitations in the non-electric generating unit “sector” (non-EGUs).<sup>5,6</sup> The rule includes ozone season NO<sub>x</sub> emissions limitations for non-EGUs with an initial compliance date of 2026 for 20 states. A summary of the non-EGU industries, emissions unit types, form of final emissions limits, and final emissions limits is presented below in Table ES-1. A more detailed summary of the emissions limits can be found in Section I.B. of the preamble. For a discussion of changes to

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<sup>5</sup> 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. The memorandum is available in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150>.

<sup>6</sup> To further evaluate the industries and emissions unit types identified and to establish the 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 state implementation plan (SIP) submittals, consent decrees, and permit limits. That evaluation is detailed in the *Non-EGU Sectors Technical Support Document (TSD)* prepared for the proposed FIP. The TSD is available in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145>.



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emissions limits between the proposed FIP and the final rule, see Chapters 1 and 4 of this RIA, and Section V.C of the preamble to the final rule and the Final Non-EGU Sectors TSD.

**Table ES-1. Summary of Non-EGU Industries, Emissions Unit Types, Form of Final Emissions Limits, and Final Emissions Limits**

Industry	Emissions Unit Type	Form of Final Emissions Limits	Final Emissions Limits
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engines	Grams per horsepower per hours (g/hp-hr)	Four Stroke Rich Burn: 1.0 g/hp-hr Four Stroke Lean Burn: 1.5 g/hp-hr Two Stroke Lean Burn: 3.0 g/hp-hr
Cement and Concrete Product Manufacturing	Kilns	Pounds per ton (lbs/ton) of clinker	Long Wet: 4.0 lb/ton Long Dry: 3.0 lb/ton Preheater: 3.8 lb/ton Precalciner: 2.3 lb/ton Preheater/Precalciner: 2.8 lb/ton
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	lbs/mmBtu <sup>a</sup>	Test and set limit based on installation of Low-NOx Burners
Glass and Glass Product Manufacturing	Furnaces	lbs/ton glass produced	Container Glass Furnace: 4.0 lb/ton Pressed/Blown Glass Furnace: 4.0 lb/ton Fiberglass Furnace: 4.0 lb/ton Flat Glass Furnace: 9.2 lb/ton
Iron and Steel Mills and Ferroalloy Manufacturing Metal Ore Mining Basic Chemical Manufacturing Petroleum and Coal Products Manufacturing Pulp, Paper, and Paperboard Mills	Boilers	lbs/mmBtu <sup>a</sup>	Coal: 0.20 lb/mmBtu Residual Oil: 0.20 lb/mmBtu Distillate Oil: 0.12 lb/mmBtu Natural Gas: 0.08 lb/mmBtu
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ppmvd on a 24-hour averaging period and ppmvd on a 30-day averaging period	110 ppmvd on a 24-hour averaging period 105 ppmvd on a 30-day averaging period

<sup>a</sup> Heat input limit.

For the final rule, using 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 (CMDB),<sup>7</sup> the EPA estimated NO<sub>x</sub> emissions reductions and costs for the year 2026. For additional details about the steps taken to estimate emissions units, emissions reductions, and

<sup>7</sup> 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-modelstoos-air-pollution>.

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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.<sup>8</sup>

## ES.2 Baseline and Analysis Years

The final rule sets forth the requirements to eliminate states’ significant contribution to downwind nonattainment or interference with maintenance of the 2015 ozone NAAQS. To develop and evaluate control strategies for addressing these obligations, it is important to first establish a baseline projection of air quality in the analysis years of 2023 and 2026, taking into account currently on-the-books Federal regulations, enforcement actions, state regulations, population, expected electricity demand growth, and where possible, economic growth. Establishing this baseline for the analysis then allows us to estimate the incremental costs and benefits of the additional emissions reductions that will be achieved by this rule.

The analysis in this RIA focuses on benefits, costs and certain impacts from 2023 through 2042. We focus on 2023 because it is by the 2023 ozone season, corresponding with the 2024 Moderate area attainment date, that significant contribution from upwind states’ must be eliminated to the extent possible. In addition, impacts for 2026 are important because this ozone season corresponds with the 2027 Serious area attainment date, and it is by this ozone season that additional requirements for NOx emissions reductions for EGUs and non-EGUs begin to apply for states whose upwind linkage to downwind receptors persists. Costs, benefits, and other impacts from compliance strategies are likely to~~may~~ persist beyond 2026, and the RIA provides costs and benefits through 2042.

## ES.3 Air Quality Modeling

The air quality modeling for the Transport FIP for the 2015 ozone NAAQS used a 2016-based modeling platform that included meteorology and base year emissions from 2016 and

<sup>8</sup> The estimates prepared using the 2019 inventory and information from the CMDDB 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 be different than those estimated in this assessment. Further, the estimated emissions reductions from and costs to meet the final rule emissions limits may be different than those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

**Commented [EO 1286613]:** Doesn't EPA expect additional benefits from the backstop kicking in after 2030? If so, this "may" seems unnecessarily weak. Net benefits will continue well after 2026. Indeed, if net benefits will likely continue even after 2042, EPA should say so as well.

**Commented [EPA14R13]:** We made a line edit. In addition, we selected a 20-year analytical period because it is generally representative of and covers the lifetime of the capital equipment anticipated to be installed in response to the rule. We did not specifically assess net benefits after 2042.

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projected emissions for 2023 and 2026. The air quality modeling to support the analyses in this final RIA included photochemical model simulations for the 2016 base year and 2026 future year. The model simulations included source apportionment modeling for the 2026 baseline to quantify the contributions to ozone from EGU and from non-EGU NOx emissions and the contributions to PM<sub>2.5</sub> from EGU emissions of NOx, SO<sub>2</sub>, and directly emitted primary PM<sub>2.5</sub>.<sup>9</sup> Source apportionment modeling for ozone and PM<sub>2.5</sub> was performed to provide contributions on a state-by-state basis. All of the air quality model simulations were performed using the Comprehensive Air Quality Model with Extensions (CAMx) version 7.10. The CAMx nationwide modeling domain (i.e., the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12 x 12 km.

The modeling results for 2016 and 2026, in conjunction with emissions data for the 2023 baseline, 2026 baseline, the final rule, and more and less stringent alternatives (regulatory control alternatives) in 2023 and 2026, were used to construct the air quality spatial fields that reflect the influence of emissions changes between the baseline and each regulatory control alternative. These spatial fields provide the air quality inputs to calculate health benefits for the Transport FIP for the 2015 ozone NAAQS and to inform the environmental justice impact analysis in Chapter 7. The spatial fields were constructed based on a method that uses ozone and PM<sub>2.5</sub> contributions from emissions in individual states and state-level emissions reductions for each of the regulatory control alternatives coupled with baseline spatial fields of ozone and PM<sub>2.5</sub> concentrations. This method, as described in Chapter 3, was used most recently in the RIA for this proposal. In addition to the modeling to create spatial fields, we also performed air quality modeling to assess the parts per billion (ppb) impacts on projected ozone design values at monitoring sites nationwide in 2026 attributable to the EGU and non-EGU ozone season NOx emissions reductions projections from this final rule.

**Commented [EO 1286615]:** Have air quality effects to Canada and Mexico been quantified? Could they be? Note that CSAPR's RIA acknowledged unquantified benefits to Canada and Mexico.

**Commented [EPA16R15]:** There are air quality impacts in Canada and perhaps to some extent in Mexico. We did not include Canada and Mexico in the environmental justice and health benefits assessment.

<sup>9</sup> The ozone source apportionment modeling used for the proposed rule analyses is also used for this final rule analysis. In this regard, the contribution modeling is based on 2026 base case emissions that were developed for the proposed rule. At proposal, benefits associated with reductions in PM<sub>2.5</sub> concentrations were derived based on Benefit per Ton estimates for EGUs. For this final rule, we performed source apportionment modeling for PM<sub>2.5</sub> using the same 2026 emissions inventory that was used as input to the ozone source apportionment modeling.

**ES.4 Control Strategies and Emissions Reductions**

The RIA analyzes emissions budgets for EGUs and ozone season emissions limits for non-EGUs, as well as a more and a less stringent alternative to the final rule. The more and less stringent alternatives differ from the Transport FIP for the 2015 ozone NAAQS in that they set different EGU NO<sub>x</sub> ozone season emission budgets and different dates for compliance with unit-specific emission limits for the affected EGUs and estimate different control technologies for some emissions units for the affected non-EGUs. Table ES-2, below presents the less stringent alternatives, final rule requirements, and more stringent alternatives for EGUs and non-EGUs. While the EGUs are required to comply with emissions budgets in 2023, tightening in 2026 for some states, along with a backstop emission rate for coal units, Table ES-2 also describes exogenously imposed compliance assumptions (i.e., control strategies) in the power sector modeling for purposes of the analysis (e.g., installation of state-of-the-art combustion controls and fully operating SNCRs and SCRs). Other control strategies are endogenous to the EGU analysis, such as changes in the dispatch order of generators and installation of post-combustion controls.

For non-EGUs, to establish the 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 state implementation plan (SIP) submittals, consent decrees, and permit limits. We assumed control technologies would be adopted for compliance with the limitations in this analysis. For the purposes of summarizing the results of the benefits and costs of these alternatives, the less stringent alternative for EGUs is presented with the less stringent alternative for non-EGUs. However, the cost, emissions, and energy impacts for the EGU and non-EGU alternatives are evaluated separately.

**Table ES-2. Regulatory Control Alternatives for EGUs and Non-EGUs**

Regulatory Control Alternative	NO <sub>x</sub> Controls Implemented for EGUs within IPM <sup>a,b</sup>
Less Stringent Alternative	1) 2023 onwards: Fully operate existing selective catalytic reduction (SCRs) during ozone season
	2) 2023 onwards: Fully operate existing selective non-catalytic reduction (SNCRs) during ozone season
	3) In 2023 install state-of-the-art combustion controls <sup>c</sup>
	4) In 2030 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls. <sup>d</sup>

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	(All Controls above and)
Final Rule	5) In 2025 model run year, impose Engineering Analysis derived emissions budgets that assume installation of SCR controls on coal units greater than 100 MW within the 19-state region that lack SCR controls.
	(Controls 1 – 5 above and)
More Stringent Alternative	6) In 2025 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls, forcing units to retrofit or retire.
<b>Regulatory Control Alternative</b>	<b>NOx Emissions Limits for Non-EGUs – Emissions Unit Types, Industries, and Controls Assumed for Compliance</b>
	1) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – Adjust Air-to-Fuel Ratio
	2) Kilns in Cement and Cement Product Manufacturing – install SNCR
	3) Reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing – install Low NOx burners (LNB)
Less Stringent Alternative	4) Furnaces in Glass and Glass Product Manufacturing – install LNB
	5) 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 – install SNCR
	6) Combustors or Incinerators in Solid Waste Combustors and Incinerators – install Advanced NSCR (ANSCR) or LN <sup>TM</sup> and SNCR <sup>e</sup>
	(Controls 2, 3, 4, and 6 above, plus changes in assumed controls noted below)
Final Rule	7) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – depending on engine type, install <i>Layered Combustion, non-selective catalytic reduction (NSCR), or SCR</i>
	8) 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 – install <i>SCR (coal- or oil-fired) or LNB and FGR (natural gas-fired only)</i>
	(Controls 3, 6, 7 above, plus changes in assumed controls noted below)
More Stringent Alternative	9) Kilns in Cement and Cement Product Manufacturing – install <i>SCR</i>
	10) Furnaces in Glass and Glass Product Manufacturing – install <i>SCR</i>
	11) 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 – install <i>SCR (natural gas-fired only)</i>

<sup>a</sup> IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. For this analysis, IPM maps the calendar year 2023 to run year 2023, calendar years 2024-2026 to run year 2025 and calendar years 2027-2029 to run year 2028. For model details, please see Chapter 2 of the IPM documentation.

<sup>b</sup> NOx mass budgets are imposed in all run years in IPM (2023-2050) consistent with the measures highlighted in this table.

<sup>c</sup> The final rule implementation allows for the reduction associated with state-of-the-art combustion controls to occur by 2024. It is captured in 2023 in this analysis to fully assess the impact of the mitigation measures occurring prior to 2026.

<sup>d</sup> For the 19 states with EGU obligations that are linked in 2026 the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam-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 units greater than 100 MW that have historically emitted at least 150 tons of NO<sub>x</sub> per ozone season. 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. The 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.

**Commented [EO 1286617]:** What are the costs and benefits of these individual provisions, separate from the more-stringent provision for EGUs?

**Commented [EPA18R17]:** Note that the rule establishes emissions limits and does not require specific controls. Also, as noted in the Agency’s preamble responses (passback #1), the more stringent alternative for non-EGUs reflects estimated controls that are not widely demonstrated in practice (i.e., SCR for cement kilns, glass furnaces).

In addition, we do not have benefits estimates associated with those individual control technology applications.

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<sup>c</sup> Covanta has developed a proprietary low NO<sub>x</sub> combustion system (LN<sup>TM</sup>) that involves staging of combustion air. The system is a trademarked system and Covanta has received a patent for the technology.

For 2023, total ozone season NO<sub>x</sub> emissions reductions of 10,000 tons are from EGUs; for 2026 total ozone season NO<sub>x</sub> emissions reductions of ~~7~~20,000 tons are from EGUs and non-EGUs, and for 2030 total ozone season NO<sub>x</sub> emissions reductions of ~~79~~84,000 tons are from EGUs and non-EGUs.

#### ES.4.1 EGUs

For the NO<sub>x</sub> controls for EGUs identified in Table ES-2, under the final rule and the less stringent and more stringent alternatives, 232 EGUs not already doing so in 2019 are assumed to fully operate existing SCRs. Under the final rule and the less stringent and more stringent alternatives, 39 units are assumed to fully operate existing SNCRs. Under the final rule and the less stringent and more stringent alternatives, 9 units are assumed to install state-of-the-art combustion controls. The book-life of the new combustion controls is assumed to be 15 years.

By 2030 the final rule is projected to result in an additional 14 GW of coal retirements nationwide relative to the baseline, constituting a reduction of 13 percent of national coal capacity, partially reflecting some earlier retirements under the rule relative to the baseline. Additionally, the rule is projected to incentivize an incremental 8 GW of SCR retrofit at coal plants. The rule is also projected to result in an incremental 3 GW of renewable capacity additions in 2025, consisting primarily of solar capacity builds. These builds reflect early action or builds that would otherwise have occurred later in the forecast period.

Table ES-3. shows the ozone season NO<sub>x</sub> emissions reductions expected from the final rule as well as the more and less stringent alternatives analyzed from 2023 through 2027, and for 2030, 2035, and 2042. In addition, Table ES-3 also shows the annual NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, and CO<sub>2</sub> emissions reductions expected from the final rule as well as the more and less stringent alternatives analyzed from 2023 through 2027, and for 2030, 2035, and 2042.<sup>10</sup> [Under the more stringent alternative, the modeling projects a higher ratio of SCR retrofits to retirements, resulting in higher emissions projected under this alternative in later years.](#)

<sup>10</sup> EGU results reflect IPM outputs for model run years (2023, 2025, 2028, 2030, 2035, 2040, and 2045). All other years are linearly interpolated.

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**Table ES-3. EGU Ozone Season NO<sub>x</sub> Emissions Changes and Annual Emissions Changes for NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, and CO<sub>2</sub> for the Regulatory Control Alternatives from 2023 – 2042<sup>11</sup>**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>2023</b>			
NO <sub>x</sub> (ozone season)	10,000	10,000	10,000
NO <sub>x</sub> (annual)	15,000	15,000	15,000
SO <sub>2</sub> (annual)	1,000	3,000	1,000
CO <sub>2</sub> (annual, thousand metric)	-	-	-
PM <sub>2.5</sub> (annual)	-	-	-
<b>2024</b>			
NO <sub>x</sub> (ozone season)	21,000	10,000	33,000
NO <sub>x</sub> (annual)	25,000	15,000	57,000
SO <sub>2</sub> (annual)	19,000	5,000	59,000
CO <sub>2</sub> (annual, thousand metric)	10,000	4,000	20,000
PM <sub>2.5</sub> (annual)	1,000	-	1,000
<b>2025</b>			
NO <sub>x</sub> (ozone season)	32,000	10,000	56,000
NO <sub>x</sub> (annual)	35,000	15,000	99,000
SO <sub>2</sub> (annual)	38,000	7,000	118,000
CO <sub>2</sub> (annual, thousand metric)	21,000	8,000	40,000
PM <sub>2.5</sub> (annual)	2,000	1,000	2,000
<b>2026</b>			
NO <sub>x</sub> (ozone season)	25,000	8,000	49,000
NO <sub>x</sub> (annual)	29,000	12,000	88,000
SO <sub>2</sub> (annual)	29,000	5,000	104,000
CO <sub>2</sub> (annual, thousand metric)	16,000	6,000	34,000
PM <sub>2.5</sub> (annual)	1,000	-	2,000
<b>2027</b>			
NO <sub>x</sub> (ozone season)	19,000	6,000	43,000
NO <sub>x</sub> (annual)	22,000	9,000	78,000
SO <sub>2</sub> (annual)	21,000	4,000	91,000
CO <sub>2</sub> (annual, thousand metric)	10,000	3,000	28,000
PM <sub>2.5</sub> (annual)	1,000	-	2,000
<b>2030</b>			
NO <sub>x</sub> (ozone season)	34,000	33,000	31,000
NO <sub>x</sub> (annual)	62,000	59,000	50,000
SO <sub>2</sub> (annual)	93,000	98,000	51,000
CO <sub>2</sub> (annual, thousand metric)	26,000	23,000	8,000
PM <sub>2.5</sub> (annual)	1,000	1,000	-
<b>2035</b>			
NO <sub>x</sub> (ozone season)	29,000	30,000	27,000
NO <sub>x</sub> (annual)	46,000	46,000	41,000
SO <sub>2</sub> (annual)	21,000	19,000	15,000
CO <sub>2</sub> (annual, thousand metric)	16,000	15,000	8,000
PM <sub>2.5</sub> (annual)	1,000	1,000	-
<b>2042</b>			

<sup>11</sup> This analysis is limited to the geographically contiguous lower 48 states.

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	Final Rule	Less Stringent Alternative	More Stringent Alternative
NOx (ozone season)	22,000	22,000	22,000
NOx (annual)	23,000	22,000	21,000
SO <sub>2</sub> (annual)	15,000	15,000	7,000
CO <sub>2</sub> (annual, thousand metric)	9,000	8,000	4,000
PM <sub>2.5</sub> (annual)	-	-	-

Emissions changes for NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>2.5</sub> are in tons.

The Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (IRA) includes significant additional new generation incentives targeting more efficient and lower-emitting sources of generation that is likely to meaningfully affect the U.S. generation mix in the future and increase the pace of new lower-emitting generation replacing some of older higher-emitting generating capacity. We include an appendix to Chapter 4 to describe the EGU compliance behavior, costs, and emissions reductions that include adjustments made to the IPM baseline to account for the potential effects of the IRA of 2022 on the power sector costs, emission reductions, and other impacts from this final rule.

#### ES.4.2 Non-EGUs

Table ES-4 below provides a summary of the 2019 ozone season emissions for non-EGUs for the 20 states subject to the rule in 2026, along with the estimated ozone season reductions for the final rule and the less and more stringent alternatives for 2026.<sup>12</sup> The EPA did not estimate emissions reductions of SO<sub>2</sub>, PM<sub>2.5</sub>, CO<sub>2</sub> and other pollutants that may be associated with controls on non-EGU emissions units; though based on the estimated emissions reductions of NOx and typical relationships between NOx and these othersuch as pollutants, there are likely to be reductions of those additional pollutants ~~may also be substantial~~. For the final rule, 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. Table ES-5 below shows the industries, emissions unit types, assumed control technology that meets the final emissions limits and the estimated number of emissions units

<sup>12</sup> EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term emissions reductions. The analysis assumes that the 2019 emissions from the emissions units will be the same in 2026 and later years.

**Commented [EO 1286619]:** Why not? Can these be characterized as likely significant?

**Commented [EPA20R19]:** The EPA currently does not have or maintain a database of control efficiencies by pollutant for each of the control technologies assumed for compliance with the non-EGU emissions limits in the final rule.

**Commented [EPA21]:** 3/10/2023: Please consider something to this effect.

**Commented [EPA22R21]:** Thank you. Made clarifying edits to suggested language.



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expected to install each control (Table ES-1 above summarizes the industries, emissions unit types, and assumed controls for the final rule). For additional results for 2026 – including estimated emissions reductions and costs by state and estimated emissions reductions and costs by state and industry – see the above cited memo. [The analysis in the RIA assumes that the estimated reductions in 2026 for non-EGUs will be the same in later years.](#)

**Table ES-4. Ozone Season NO<sub>x</sub> Emissions and Emissions Reductions (tons) for the Final Rule and the Less and More Stringent Alternatives for Non-EGUs in 2026**

State	2019 Ozone Season Emissions <sup>a</sup>	Final Rule – Ozone Season NO <sub>x</sub> Reductions	Less Stringent – Ozone Season NO <sub>x</sub> Reductions	More Stringent – Ozone Season NO <sub>x</sub> 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
NJ	2,078	242	242	258
NV	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
<b>Totals</b>	<b>302,425</b>	<b>44,616</b>	<b>16,786</b>	<b>67,728</b>

<sup>a</sup> 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.

**Commented [EO 1286623]:** What about results for other years?

**Commented [EPA24R23]:** The memo does not include results for years other than 2026.

As noted in the preamble, the analysis in the RIA assumes that the estimated reductions in 2026 will be the same in later years.

For consistency with the preamble, we added that language here.

**Commented [EO 1286625]:** Correct?

**Commented [EPA26R25]:** Yes, thank you.

**Commented [EO 1286627]:** So this is nearly twice the EGU reductions expected in the 2026 ozone season (which are 25,000), correct? Given the importance of these provisions, why aren't additional years shown?

**Commented [EPA28R27]:** Please see response and additional language above.

**Commented [EO 1286629]:** The difference between the final rule and more stringent option for non-EGUs is 23,000 in 2026, almost the same as the reductions for EGUs in 2026. Why are these additional reductions not cost-justified?

**Commented [EPA30R29]:** We believe this question was discussed/addressed during a 3/6/2023 teleconference with OMB.

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**Table ES-5. Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies that Meet Final Emissions Limits, Estimated Number of Control Installations**

<b>Industry/Industries</b>	<b>Emissions Unit Type</b>	<b>Assumed Control Technologies that Meet Final Emissions Limits</b>	<b>Estimated Number of Units Per Assumed Control</b>
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engines	NSCR or Layered Combustion (Reciprocating)	323
		Layered Combustion (2-cycle Lean Burn)	394
		SCR (4-cycle Lean Burn)	158
		NSCR (4-cycle Rich Burn)	30
Cement and Concrete Product Manufacturing	Kiln	SNCR	16
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	19
Glass and Glass Product Manufacturing	Furnaces	LNB	61
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	LNB + FGR (Gas, No Coal or Oil)	151
Metal Ore Mining		SCR (Any Coal, Any Oil)	15
Basic Chemical Manufacturing Petroleum and Coal Products Manufacturing Pulp, Paper, and Paperboard Mills			
Solid Waste Combustors and Incinerators <sup>a</sup>	Combustors or Incinerators	ANSCR	57
		LN <sup>TM</sup> and SNCR	4
<b>Total</b>			<b>1,228</b>

<sup>a</sup> Twelve MWCs have existing controls, and we estimated these units will use more reagent in those controls to meet the final emissions limits.

## ES.5 Costs

Table ES-6 below summarizes the present value (PV) and equivalent annualized value (EAV) of the total national compliance cost estimates for EGUs and non-EGUs for the final rule and the less and more stringent alternatives. The compliance cost estimate for EGUs is the incremental electricity generation system cost associated with complying with the emission budgets and backstop emission rate. [Chapter 4, Section 4.3 describes the modeling and methodology used to estimate EGU costs and Section 4.5 presents results, including impacts on fuel use, prices, and generation mix.](#) The compliance cost estimate for non-EGUs is the engineering cost of installing pollution controls. [Chapter 4, Section 4.4 describes the methodology used to estimate non-EGU costs and Section 4.5 presents results, including average cost-per-ton estimates across industries and assumed technologies.](#) These compliance cost estimates are used as a proxy for the social cost of the rule. We present the PV of the costs over the twenty-year period 2023 to 2042. We also present the EAV, which represents a flow of constant annual values that, had they occurred in each year from 2023 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost for each year of the analysis.

**Table ES-6. Total National Compliance Cost Estimates (millions of 2016\$) for the Final Rule and the Less and More Stringent Alternatives**

	Final Rule		Less Stringent Alternative		More Stringent Alternative	
	3 Percent	7 Percent	3 Percent	7 Percent	3 Percent	7 Percent
Present Value EGU 2023-2042	\$6,800	\$3,900	\$6,800	\$3,900	\$9,500	\$6,500
Present Value Non-EGU 2026-2042	\$6,700	\$4,300	\$1,700	\$1,100	\$15,000	\$9,500
<b>Present Value Total 2023-2042</b>	<b>\$13,000</b>	<b>\$8,200</b>	<b>\$8,400</b>	<b>\$5,000</b>	<b>\$24,000</b>	<b>\$16,000</b>
EGU Equivalent Annualized Value	\$460	\$370	\$450	\$370	\$640	\$620
Non-EGU Equivalent Annualized Value	\$450	\$400	\$110	\$100	\$1,000	\$900
<b>Total Equivalent Annualized Value</b>	<b>\$910</b>	<b>\$770</b>	<b>\$570</b>	<b>\$470</b>	<b>\$1,600</b>	<b>\$1,500</b>

Note: Values have been rounded to two significant figures

**Commented [EO 1286631]:** The discussion of costs is rather limited, especially regarding non-EGUs. We suggest that this discussion should be more fulsome throughout the RIA or where applicable

**Commented [EPA32R31]:** For non-EGUs the rule establishes emissions limits and does not require specific control technology applications. As described in the 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”, we made assumptions for each industry and emissions unit type about the control technology needed to meet the final emissions limits. We used these assumed technologies to estimate emissions reductions and costs. This makes providing a more detailed discussion of costs challenging.

**Commented [EPA33R31]:** 3/10/2023: Recognizing these challenges, there is still more that EPA can and should say regarding these costs in this RIA. For example, EPA could draw on some of the text in accompanying TSDs to illustrate the range, scope, and magnitude of the costs of various controls that are likely to be used

**Commented [EPA34R31]:** This section of the Executive Summary is intended to provide an overview of total costs. Chapter 4 includes more detailed discussions of the methodologies used to estimate costs for EGUs and non-EGUs, as well as presents results. We added text to refer to these more detailed discussions in Chapter 4.

## ES.6 Benefits

### ES.6.1 Health Benefits Estimates

The final rule is expected to reduce ozone season and annual NO<sub>x</sub> emissions. In the presence of sunlight, NO<sub>x</sub> and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO<sub>x</sub> emissions generally reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs. In addition to NO<sub>x</sub>, the rule is also expected to reduce emissions of direct PM<sub>2.5</sub> and SO<sub>2</sub> throughout the year from EGUs. Because NO<sub>x</sub> and SO<sub>2</sub> are also precursors to secondary formation of ambient PM<sub>2.5</sub>, reducing these emissions would reduce human exposure to ambient PM<sub>2.5</sub> throughout the year and would reduce the incidence of PM<sub>2.5</sub>-attributable health effects.

In this RIA for the Transport FIP for the 2015 ozone NAAQS, the EPA quantifies benefits of changes in ozone and PM<sub>2.5</sub> concentrations. The health effects and effect estimates, and how they were selected, are described in the technical support document for the 2022 PM NAAQS Reconsideration Proposal RIA titled *Estimating PM<sub>2.5</sub>- and Ozone-Attributable Health Benefits*. The approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized in Chapter 5.

Table ES-7 and Table ES-8 report the estimated economic value of avoided premature deaths and illness in 2023 and 2026 relative to the baseline along with the 95% confidence interval. The number of reduced estimated deaths and illnesses from the final rule and more and less stringent alternatives is calculated from the sum of individual reduced mortality and illness risk across the population. In each of these tables, for each discount rate and regulatory control alternative, multiple benefits estimates are presented reflecting alternative ozone and PM<sub>2.5</sub> mortality risk estimates.

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**Table ES-7. Estimated Discounted Economic-Monetized Value of Avoided Ozone-Related Premature Mortality and Illness for the Final Rule and the Less and More Stringent Alternatives in 2023 (95% Confidence Interval; millions of 2016\$)<sup>a,b</sup>**

Disc. Rate	Pollutant	Final Rule		More Stringent Alternative		Less Stringent Alternative	
3%	Ozone	\$100	\$820	\$110	\$840	\$100	\$810
	Benefits	(\$27 to \$220) <sup>c</sup>	and (\$91 to \$2,100) <sup>d</sup>	(\$28 to \$230) <sup>c</sup>	and (\$94 to \$2,200) <sup>d</sup>	(\$27 to \$220) <sup>c</sup>	and (\$91 to \$2,100) <sup>d</sup>
7%	Ozone	\$93	\$730	\$96	\$750	\$93	\$730
	Benefits	(\$17 to 210) <sup>c</sup>	and (\$75 to \$1,900) <sup>d</sup>	(\$18 to \$210) <sup>c</sup>	and (\$77 to \$2,000) <sup>d</sup>	(\$17 to \$210) <sup>c</sup>	and (\$75 to \$1,900) <sup>d</sup>

<sup>a</sup> 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.

<sup>b</sup> We estimated ozone benefits for changes in NOx for the ozone season for EGUs in 2023. 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.

<sup>c</sup> Using the pooled short-term ozone exposure mortality risk estimate.

<sup>d</sup> Using the long-term ozone exposure mortality risk estimate.

**Table ES-8. Estimated Discounted Economic-Monetized Value of Avoided Ozone and PM<sub>2.5</sub>-Attributable Premature Mortality and Illness for the Final Rule and the Less and More Stringent Alternatives in 2026 (95% Confidence Interval; millions of 2016\$)<sup>a,b</sup>**

Disc. Rate	Pollutant	Final Rule		More Stringent Alternative		Less Stringent Alternative	
3%	Ozone	\$1,100	\$9,400	\$1,900	\$15,000	\$420	\$3,400
	Benefits	(\$280 to \$2,400) <sup>c</sup>	and (\$1,000 to \$25,000) <sup>d</sup>	(\$470 to \$4,000) <sup>c</sup>	and (\$1,700 to \$40,000) <sup>d</sup>	(\$110 to \$900) <sup>c</sup>	and (\$380 to \$8,900) <sup>d</sup>
	PM Benefits	\$2,000 (\$220 to \$5,300)	and \$4,400 (\$430 to \$12,000)	\$6,400 (\$690 to \$17,000)	and \$14,000 (\$1,300 to \$37,000)	\$530 (\$57 to \$1,400)	and \$1,100 (\$110 to \$3,100)
	Ozone plus PM Benefits	\$3,200 (\$500 to \$7,700) <sup>c</sup>	and \$14,000 (\$1,500 to \$36,000) <sup>d</sup>	\$8,300 (\$1,200 to \$21,000) <sup>c</sup>	and \$29,000 (\$3,000 to \$77,000) <sup>d</sup>	\$950 (\$160 to \$2,300) <sup>c</sup>	and \$4,600 (\$490 to \$12,000) <sup>d</sup>
7%	Ozone	\$1,000	\$8,400	\$1,700	\$14,000	\$380	\$3,100
	Benefits	(\$180 to \$2,300) <sup>c</sup>	and (\$850 to \$22,000) <sup>d</sup>	(\$300 to \$3,800) <sup>c</sup>	and (\$1,400 to \$36,000) <sup>d</sup>	(\$68 to \$850) <sup>c</sup>	and (\$310 to \$8,100) <sup>d</sup>
	PM Benefits	\$1,800 (\$190 to \$4,700)	and \$3,900 (\$380 to \$11,000)	\$5,800 (\$600 to \$15,000)	and \$12,000 (\$1,200 to \$33,000)	470 (\$50 to \$1,200)	and \$1,000 (\$100 to \$2,800)
	Ozone plus PM Benefits	\$2,800 (\$370 to \$7,000) <sup>c</sup>	and \$12,000 (\$1,200 to \$33,000) <sup>d</sup>	\$7,500 (\$910 to \$19,000) <sup>c</sup>	and \$26,000 (\$2,600 to \$69,000) <sup>d</sup>	\$850 (\$120 to \$2,100) <sup>c</sup>	and \$4,100 (\$410 to \$11,000) <sup>d</sup>

<sup>a</sup> 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.

<sup>b</sup> We estimated changes in NOx for the ozone season and annual changes in PM<sub>2.5</sub> and PM<sub>2.5</sub> precursors in 2026.

<sup>c</sup> Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Di et al. (2017) long-term PM<sub>2.5</sub> exposure mortality risk estimate.

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<sup>d</sup> Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Di et al. (2017) long-term PM<sub>2.5</sub> exposure mortality risk estimate.

### ES.6.2 Climate Benefits

Elevated concentrations of GHGs in the atmosphere have been warming the planet, leading to changes in the Earth's climate including changes in the frequency and intensity of heat waves, precipitation, and extreme weather events, rising seas, and retreating snow and ice. The well-documented atmospheric changes due to anthropogenic GHG emissions are changing the climate at a pace and in a way that threatens human health, society, and the natural environment. Climate change touches nearly every aspect of public welfare in the U.S. with resulting economic costs, including: changes in water supply and quality due to changes in drought and extreme rainfall events; increased risk of storm surge and flooding in coastal areas and land loss due to inundation; increases in peak electricity demand and risks to electricity infrastructure; and the potential for significant agricultural disruptions and crop failures (though offset to some extent by carbon fertilization).

There will be important climate benefits associated with the CO<sub>2</sub> emissions reductions expected from this final rule. Climate benefits from reducing emissions of CO<sub>2</sub> can be monetized using estimates of the social cost of carbon (SC-CO<sub>2</sub>). See Chapter 5, Section 5.2 for more discussion of the approach to monetization of the climate benefits associated with this rule.

### ES.6.3 Total Monetized Human Health and Climate Benefits

Tables ES-9 through ES-11 below present the total monetized health and climate benefits for the final rule and the less and more ~~and less~~ stringent alternatives for 2023, 2026, and 2030.

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**Table ES-9. Combined ~~Monetized Health Benefits~~ and Climate Benefits for the Final Rule and Less and More ~~and Less~~ Stringent Alternatives for 2023 (millions of 2016\$)**

SC-CO <sub>2</sub> Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only <sup>a</sup>
	3%	7%	
<b>Final Rule</b>			
5% (average)	\$100 and \$820	\$94 and \$730	\$1
3% (average)	\$100 and \$820	\$98 and \$740	\$5
2.5% (average)	\$110 and \$820	\$100 and \$740	\$7
3% (95 <sup>th</sup> percentile)	\$110 and \$830	\$110 and \$750	\$14
<b>Less Stringent Alternative</b>			
5% (average)	\$100 and \$810	\$94 and \$730	\$1
3% (average)	\$100 and \$820	\$97 and \$730	\$4
2.5% (average)	\$110 and \$820	\$99 and \$730	\$6
3% (95 <sup>th</sup> percentile)	\$110 and \$830	\$100 and \$740	\$12
<b>More Stringent Alternative</b>			
5% (average)	\$110 and \$840	\$97 and \$750	\$1
3% (average)	\$110 and \$840	\$100 and \$760	\$5
2.5% (average)	\$120 and \$850	\$100 and \$760	\$7
3% (95 <sup>th</sup> percentile)	\$120 and \$850	\$110 and \$770	\$14

<sup>a</sup> Climate benefits are based on changes (reductions) in CO<sub>2</sub> emissions and are calculated using four different estimates of the social cost of carbon (SC-CO<sub>2</sub>) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95<sup>th</sup> percentile at 3 percent discount rate).

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**Table ES-10. Combined Monetized Health Benefits and Climate Benefits for the Final Rule and Less and More and Less-Stringent Alternatives for 2026 (millions of 2016\$)**

SC-CO <sub>2</sub> Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only <sup>a</sup>
	3%	7%	
<b>Final Rule</b>			
5% (average)	\$3,500 and \$14,000	\$3,100 and \$13,000	\$250
3% (average)	\$4,000 and \$15,000	\$3,600 and \$13,000	\$830
2.5% (average)	\$4,400 and \$15,000	\$4,000 and \$14,000	\$1,220
3% (95 <sup>th</sup> percentile)	\$5,700 and \$16,000	\$5,300 and \$15,000	\$2,500
<b>Less Stringent Alternative</b>			
5% (average)	\$1,000 and \$4,600	\$940 and \$4,200	\$91
3% (average)	\$1,200 and \$4,900	\$1,100 and \$4,400	\$300
2.5% (average)	\$1,400 and \$5,000	\$1,300 and \$4,500	\$440
3% (95 <sup>th</sup> percentile)	\$1,800 and \$5,500	\$1,700 and \$5,000	\$900
<b>More Stringent Alternative</b>			
5% (average)	\$8,800 and \$30,000	\$13,000 and \$27,000	\$540
3% (average)	\$10,000 and \$31,000	\$14,000 and \$28,000	\$1,800
2.5% (average)	\$11,000 and \$32,000	\$15,000 and \$29,000	\$2,600
3% (95 <sup>th</sup> percentile)	\$14,000 and \$34,000	\$17,000 and \$31,000	\$5,400
5% (average)	\$3,500 and \$14,000	\$3,100 and \$13,000	\$340
3% (average)	\$4,300 and \$15,000	\$3,900 and \$13,000	\$1,100
2.5% (average)	\$4,800 and \$15,000	\$4,400 and \$14,000	\$1,600
3% (95 <sup>th</sup> percentile)	\$6,600 and \$17,000	\$6,200 and \$16,000	\$3,400
<b>Less Stringent Alternative</b>			
5% (average)	\$1,100 and \$4,700	\$980 and \$4,200	\$130
3% (average)	\$1,400 and \$5,000	\$1,300 and \$4,500	\$420
2.5% (average)	\$1,600 and \$5,200	\$1,500 and \$4,700	\$620
3% (95 <sup>th</sup> percentile)	\$2,200 and \$5,800	\$2,100 and \$5,400	\$1,300
<b>More Stringent Alternative</b>			
5% (average)	\$8,900 and \$30,000	\$13,000 and \$27,000	\$640
3% (average)	\$10,000 and \$31,000	\$14,000 and \$28,000	\$2,100
2.5% (average)	\$11,000 and \$32,000	\$15,000 and \$29,000	\$3,100
3% (95 <sup>th</sup> percentile)	\$15,000 and \$35,000	\$18,000 and \$32,000	\$6,400

<sup>a</sup> Climate benefits are based on changes (reductions) in CO<sub>2</sub> emissions and are calculated using four different estimates of the social cost of carbon (SC-CO<sub>2</sub>) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95<sup>th</sup> percentile at 3 percent discount rate).



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**Table ES-11. Combined Monetized Health Benefits and Climate Benefits for the Final Rule and Less and More and Less-Stringent Alternatives for 2030 (millions of 2016\$)**

SC-CO <sub>2</sub> Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only <sup>a</sup>
	3%	7%	
<b>Final Rule</b>			
5% (average)	\$3,900 and \$15,000	\$3,500 and \$14,000	\$470
3% (average)	\$4,900 and \$16,000	\$4,500 and \$15,000	\$1,500
2.5% (average)	\$5,600 and \$17,000	\$5,200 and \$15,000	\$2,200
3% (95 <sup>th</sup> percentile)	\$8,000 and \$19,000	\$7,600 and \$18,000	\$4,600
<b>Less Stringent Alternative</b>			
5% (average)	\$1,400 and \$5,300	\$1,300 and \$4,800	\$420
3% (average)	\$2,300 and \$6,200	\$2,300 and \$5,700	\$1,300
2.5% (average)	\$3,000 and \$6,800	\$2,900 and \$6,300	\$2,000
3% (95 <sup>th</sup> percentile)	\$5,100 and \$8,900	\$5,000 and \$8,400	\$4,100
<b>More Stringent Alternative</b>			
5% (average)	\$9,200 and \$31,000	\$8,300 and \$28,000	\$150
3% (average)	\$9,500 and \$31,000	\$8,600 and \$28,000	\$480
2.5% (average)	\$9,700 and \$32,000	\$8,800 and \$28,000	\$700
3% (95 <sup>th</sup> percentile)	\$10,000 and \$32,000	\$9,500 and \$29,000	\$1,400

<sup>a</sup> Climate benefits are based on changes (reductions) in CO<sub>2</sub> emissions and are calculated using four different estimates of the social cost of carbon (SC-CO<sub>2</sub>) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95<sup>th</sup> percentile at 3 percent discount rate).

#### ES.6.4 Additional Unquantified Benefits

Data, time, and resource limitations prevented the EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with direct exposure to NO<sub>2</sub> and SO<sub>2</sub> (independent of the role NO<sub>2</sub> and SO<sub>2</sub> play as precursors to ozone and PM<sub>2.5</sub>), as well as ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. While all health benefits and welfare benefits were not able to be quantified, it does not imply that there are not additional benefits associated with reductions in exposures to ozone, PM<sub>2.5</sub>, NO<sub>2</sub> or SO<sub>2</sub>. For a qualitative description of these and water quality benefits, please see Chapter 5, section 5.4.

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## ES.7 Environmental Justice Impacts

Environmental justice (EJ) concerns for each rulemaking are unique and should be considered on a case-by-case basis, and the EPA’s EJ Technical Guidance<sup>13</sup> states that “[t]he 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, the EPA developed an analytical approach that considers the purpose and specifics of the rulemaking, as well as the nature of known and potential exposures and impacts. For the rule, we quantitatively evaluate 1) the proximity of affected facilities to potentially vulnerable and/or overburdened populations for consideration of local pollutants impacted by this rule but not modeled here (Chapter 7, Section 7.3) and 2) the distribution of ozone and PM<sub>2.5</sub> concentrations in the baseline and changes due to the final rulemaking across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, age, sex, educational attainment, and degree of linguistic isolation (Chapter 7, 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 provide information as to whether there may be potential EJ concerns associated with environmental stressors, in this case such as, local NO<sub>2</sub> emitted from sources affected by the regulatory action for certain population groups of concern (Chapter 7, Section 7.3). The baseline demographic proximity analyses suggest that larger percentages of Hispanics, African Americans, people below the poverty level, people with less

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<sup>13</sup> U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

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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, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (e.g., NO<sub>2</sub>) 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 should not be interpreted as a direct measure of exposure or impact.

Because the pollution impacts that are the focus of this rule are often substantially downwind from affected facilities, ozone and PM<sub>2.5</sub> exposure analyses that evaluate demographic variables are better able to evaluate any potentially disproportionate pollution impacts of this rulemaking. The baseline ozone and PM<sub>2.5</sub> exposure analyses respond to question 1 from the EPA's EJ Technical Guidance document more directly than the proximity analyses, as they evaluate a form of the environmental stressor primarily affected by the regulatory action (Chapter 7, Section 7.4). Baseline ozone and PM<sub>2.5</sub> 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<sub>2.5</sub> exposures as compared to the national average. American Indians may also experience disproportionately higher ozone concentrations than the reference group. Therefore, there likely are potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline.

Finally, we evaluate how post-policy regulatory alternatives of this final rulemaking are expected to differentially impact demographic populations, informing questions 2 and 3 from the EPA's EJ Technical Guidance with regard to ozone and PM<sub>2.5</sub> exposure changes. We infer that disparities in the ozone and PM<sub>2.5</sub> concentration burdens are likely to remain after implementation of the regulatory action or alternatives under consideration. This is due to the small magnitude of the concentration changes associated with this rulemaking across population demographic subgroups, relative to baseline disparities (question 2). Also, due to the very small differences observed in the distributional analyses of post-policy ozone and PM<sub>2.5</sub> exposure

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impacts, we do not find evidence that potential EJ concerns related to ozone or PM<sub>2.5</sub> exposures will be meaningfully exacerbated or mitigated in the regulatory alternatives under consideration, compared to the baseline (question 3). Importantly, the action described in this rule is expected to lower ozone and PM<sub>2.5</sub> in many areas, including in ozone nonattainment areas, and thus mitigate some pre-existing health risks across all populations evaluated.

### **ES.8 Results of Benefit-Cost Analysis**

Below we present the annual costs and benefits estimates for 2023, 2026, and 2030, respectively. This analysis uses annual compliance costs reported above as a proxy for social costs. The estimated annual compliance costs to implement the rule, as described in this RIA, are approximately \$57 million in 2023 and \$570 million in 2026 (2016\$).

The estimated monetized health benefits from reduced ozone and PM<sub>2.5</sub> concentrations from implementation of the rule are approximately \$100 and \$820 million in 2023 (2016\$, based on a real discount rate of 3 percent). The estimated monetized climate benefits from reduced GHG emissions are approximately \$5 million in 2023 (2016\$, based on a real discount rate of 3 percent). For 2026, the estimated monetized health benefits from implementation of the rule are approximately \$3,200 and \$14,000 million (2016\$, based on a real discount rate of 3 percent). The estimated monetized climate benefits from reduced GHG emissions are approximately \$1,100 million in 2026 (2016\$, based on a real discount rate of 3 percent).

The EPA calculates the monetized net benefits of the rule by subtracting the estimated monetized compliance costs from the estimated monetized health and climate benefits in 2023, 2026, and 2030. The benefits include those to public health associated with reductions in ozone and PM<sub>2.5</sub> concentrations, as well as those to climate associated with reductions in GHG emissions. The annual monetized net benefits of the rule in 2023 (in 2016\$) are approximately \$48 and \$760 million using a 3 percent real discount rate. The annual monetized net benefits of the rule in 2026 are approximately \$3,700 and \$14,000 million using a 3 percent real discount rate. The annual monetized net benefits of the rule in 2030 are approximately \$3,600 and \$15,000 million using a 3 percent real discount rate. Table ES-12 presents a summary of the monetized health and climate benefits, costs, and net benefits of the rule and the [less and more and less](#)-stringent alternatives for 2023. Table ES-13. presents a summary of these impacts for the rule and the [less and more and less](#)-stringent alternatives for 2026. Table ES-14 presents a

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summary of these impacts for the rule and the [less and more](#) ~~and less~~ stringent alternatives for 2030. 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~~[these is tables](#) reflects.

**Table ES-12. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2023 for the U.S. (millions of 2016\$)<sup>a,b</sup>**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>Health Benefits<sup>c</sup></b>	\$100 and \$820	\$100 and \$810	\$110 and \$840
<b>Climate Benefits</b>	\$5	\$4	\$5
<b>Total Benefits</b>	\$100 and \$820	\$100 and \$820	\$110 and \$840
<b>Costs<sup>d</sup></b>	\$57	\$56	\$49
<b>Net Benefits</b>	<b>\$48 and \$760</b>	<b>\$48 and \$760</b>	<b>\$66 and \$800</b>

<sup>a</sup> 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.

<sup>b</sup> Rows may not appear to add correctly due to rounding.

<sup>c</sup> The 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%.

<sup>d</sup> 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% 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.](#)

**Table ES-13. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2026 for the U.S. (millions of 2016\$)<sup>a,b</sup>**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>Health Benefits<sup>c</sup></b>	\$3,200 and \$14,000	\$950 and \$4,600	\$8,300 and \$29,000
<b>Climate Benefits</b>	\$1,100	\$420	\$2,100
<b>Total Benefits</b>	\$4,300 and \$15,000	\$1,400 and \$5,000	\$10,000 and \$31,000
<b>Costs<sup>d</sup></b>	\$570	\$110	\$2,100
<b>Net Benefits</b>	<b>\$3,700 and \$14,000</b>	<b>\$1,300 and \$4,900</b>	<b>\$8,300 and \$29,000</b>

<sup>a</sup> 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.

<sup>b</sup> Rows may not appear to add correctly due to rounding.

<sup>c</sup> The 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%.

<sup>d</sup> 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% 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.](#)

**Table ES-14. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2030 for the U.S. (millions of 2016\$)<sup>a,b</sup>**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
Health Benefits <sup>c</sup>	\$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 <sup>d</sup>	\$1,300	\$920	\$2,100
<b>Net Benefits</b>	<b>\$3,600 and \$15,000</b>	<b>\$1,400 and \$5,300</b>	<b>\$7,400 and \$29,000</b>

<sup>a</sup> 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.

<sup>b</sup> Rows may not appear to add correctly due to rounding.

<sup>c</sup> The 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%.

<sup>d</sup> 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% 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.](#)

As part of fulfilling analytical guidance with respect to E.O. 12866, the EPA presents estimates of the present value (PV) of the monetized benefits and costs over the twenty-year period 2023 to 2042. To calculate the present value of the social net-benefits of the final rule, annual benefits and costs are discounted to 2023 at 3 percent and 7 discount rates as directed by OMB’s Circular A-4. The EPA also presents the equivalent annualized value (EAV), which represents a flow of constant annual values that, had they occurred in each year from 2023 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates mentioned earlier in the RIA. Note that EGU costs reported in this RIA for years not explicitly modeled are mapped to modeled years. For this analysis, IPM maps the calendar year 2023 to run year 2023, calendar years 2024-2026 to run year 2025 and calendar years 2027-2029 to run year 2028. Non-EGU costs are assumed to be constant throughout the time horizon.

The health benefits analysis quantifies changes in ozone concentrations in 2023 and changes in ozone and PM<sub>2.5</sub> in 2026 for each of the three regulatory control alternatives (i.e., final rule, less stringent alternative, and more stringent alternative). Analyses were also run for each year between 2023 and 2042, using the air quality model surfaces, but accounting for the change in population size in each year, income growth, and baseline mortality incidence rates at five-year increments. However, because of uncertainties associated with baseline air quality projections beyond 2026, annual health benefits beyond 2026 are based on 2026 air quality

**Commented [EO 1286635]:** Why are you using a private discount rate for this table instead of a social discount rate?

**Commented [EPA36R35]:** The EPA flagged this question for discussion in the 1<sup>st</sup> preamble/cover comments passback.

**Commented [EPA37R36]:** 3/10/2023: the preamble also refers back to the RIA; please include some description in the RIA that can be cross-referenced both in the preamble and within the RIA where appropriate

**Commented [EPA38R35]:** Per 3/10/23 teleconference, added note to table notes for tables ES-12, ES-13, and ES-14, which is consistent with text added to preamble text.

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changes. The 2023 ozone concentration changes were assumed through 2025 and the 2026 ozone and PM<sub>2.5</sub> concentration changes were assumed until 2042. Finally, climate benefits are mapped using the same model year mapping from IPM applied for the EGU cost analysis. GHG emissions reductions are multiplied by year specific social cost of carbon values.

For the twenty-year period of 2023 to 2042, the PV of the net benefits, in 2016\$ and discounted to 2023, is \$200,000 million when using a 3 percent discount rate and \$1430,000 million when using a 7 percent discount rate. The EAV is \$13,000 million per year when using a 3 percent discount rate and \$12,000 million when using a 7 percent discount rate. The comparison of benefits and costs in PV and EAV terms for the final rule can be found in Table ES-15. Estimates in the table are presented as rounded values.

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**Table ES-15. Summary of Present Values and Equivalent Annualized Values for the 2023-2042 Timeframe for Estimated Monetized Compliance Costs, Benefits, and Net Benefits for the Final Rule (millions of 2016\$, discounted to 2023)**

	Health Benefits		Climate Benefits	Cost		Net Benefits	
	3%	7%	3%	3%	7%	3%	7%
2023	\$820	\$730	\$5	\$57	\$57	\$770	\$680
2024	\$810	\$700	\$1,000	(\$5)	(\$5)	\$1,300	\$1,200
2025	\$8,600	\$7,100	\$1,000	(\$5)	(\$4)	\$9,600	\$8,100
2026	\$13,000	\$10,000	\$1,000	\$520	\$460	\$13,000	\$10,000
2027	\$13,000	\$9,700	\$230	\$530	\$450	\$13,000	\$9,700
2028	\$12,000	\$8,900	\$230	\$510	\$420	\$12,000	\$8,700
2029	\$12,000	\$8,500	\$230	\$500	\$400	\$12,000	\$8,800
2030	\$12,000	\$8,200	\$1,200	\$1,000	\$800	\$12,000	\$8,600
2031	\$12,000	\$7,800	\$1,200	\$1,000	\$740	\$12,000	\$8,200
2032	\$12,000	\$7,500	\$740	\$1,100	\$760	\$12,000	\$7,700
2033	\$11,000	\$7,000	\$730	\$1,000	\$710	\$11,000	\$7,200
2034	\$11,000	\$6,700	\$720	\$1,000	\$660	\$11,000	\$6,900
2035	\$11,000	\$6,400	\$710	\$970	\$620	\$11,000	\$6,500
2036	\$11,000	\$6,100	\$700	\$950	\$580	\$11,000	\$6,300
2037	\$11,000	\$5,800	\$690	\$920	\$540	\$11,000	\$6,000
2038	\$11,000	\$5,400	\$860	\$890	\$500	\$11,000	\$5,700
2039	\$10,000	\$5,100	\$850	\$870	\$470	\$9,900	\$5,400
2040	\$10,000	\$4,900	\$830	\$840	\$440	\$10,000	\$5,300
2041	\$10,000	\$4,600	\$820	\$820	\$410	\$9,900	\$4,900
2042	\$10,000	\$4,400	\$810	\$790	\$380	\$9,800	\$4,600
<b>PV</b>	<b>\$200,000</b>	<b>\$130,000</b>	<b>\$15,000</b>	<b>\$14,000</b>	<b>\$9,400</b>	<b>\$200,000</b>	<b>\$143,000</b>
<b>2023-2042</b>							
<b>EAV</b>							
<b>2023-2042</b>	<b>\$13,000</b>	<b>\$12,000</b>	<b>\$970</b>	<b>\$910</b>	<b>\$770</b>	<b>\$13,000</b>	<b>\$12,000</b>



## **CHAPTER 1: INTRODUCTION AND BACKGROUND**

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### **Overview**

In this final rule, the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS), the EPA sets implementation mechanisms to achieve enforceable emissions reductions required to eliminate significant contribution to nonattainment or interference with maintenance of the 2015 ozone NAAQS in other states. The initial phase of emissions reductions will begin in the 2023 ozone season with further emissions reductions being required in later years.<sup>14</sup>

The EPA is promulgating new or revised FIPs for 23 states. For 22 states the FIPs include new NO<sub>x</sub> ozone season emission budgets for EGU sources, with implementation of these emission budgets beginning in the 2023 ozone season.<sup>15</sup> The EPA is expanding the CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs require electric generating units (EGUs) within the borders of the 22 states to participate in a revised version of the CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of twelve states currently participating in the Group 3 Trading Program under FIPs or SIPs remain in the program, with revised provisions beginning in the 2023 ozone season. The FIPs also require affected EGUs within the borders of seven states currently covered by the CSAPR NO<sub>x</sub> 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. Lastly, the EPA is issuing new FIPs for three states not currently covered by any CSAPR NO<sub>x</sub> ozone season trading program (Minnesota, Nevada, and Utah).

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<sup>14</sup> The 2015 ozone NAAQS is an 8-hour standard that was set at 70 parts per billion (ppb). See 80 FR 65291 (December 28, 2015).

<sup>15</sup> In 2023, the 22 states with EGU reduction requirements include AL, AR, IL, IN, KY, LA, MD, MI, MN, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, WV, and WI. There are no EGU reductions being required from California, which if included would make 23 states.

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The FIPs that EPA is promulgating for 20 states include new NO<sub>x</sub> emissions limitations for non-electric generating unit (non-EGU) sources, with initial compliance dates for these emissions limitations beginning in 2026.<sup>16</sup>

Consistent with OMB Circular A-4 and the EPA’s *Guidelines for Preparing Economic Analyses* (2010), this regulatory impact analysis (RIA) presents the benefits and costs of the final rule from 2023 through 2042. The estimated monetized benefits are those health benefits expected to arise from reduced ozone and PM<sub>2.5</sub> concentrations and the benefits from reductions in greenhouse gases. The estimated monetized costs for EGUs are the costs of installing and operating controls and other increased costs of producing electricity to comply with the revised version of the Group 3 trading program. The estimated monetized costs for non-EGUs are the costs of installing and operating controls to meet the ozone season NO<sub>x</sub> emissions limitations.<sup>17</sup> The estimated costs for non-EGUs do not include monitoring, recordkeeping, reporting, or testing costs. Unquantified benefits and costs are described qualitatively. The RIA also provides (i) estimates of other impacts of the rule including its effect on retail electricity prices and fuel production, (ii) an assessment of how expected compliance with the rule will affect concentrations at nonattainment and maintenance receptors, and (iii) an assessment of potential environmental justice concerns. This chapter contains background information relevant to the rule and an outline of the chapters of this RIA.

## 1.1 Background

Clean Air Act (CAA or the Act) section 110(a)(2)(D)(i)(I), which is also known as the “good neighbor provision,” 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. The statute vests states with the primary responsibility to address interstate emission transport through the development of good neighbor State Implementation Plans (SIPs),

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<sup>16</sup> In 2026, the 20 states with non-EGU reduction requirements include AR, CA, IL, IN, KY, LA, MD, MI, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, and WV.

<sup>17</sup> For non-EGUs, we prepared a memorandum for the final rule that summarizes the (i) industries affected, (ii) applicability criteria, (iii) final emissions limits, (iv) estimated emissions units, and (v) estimated emissions reductions and costs (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*, is available in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668>).

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which are one component of larger SIP submittals typically required three years after the EPA promulgates a new or revised NAAQS. These larger SIPs are often referred to as “infrastructure” SIPs or iSIPs. *See* CAA section 110(a)(1) and (2).

The EPA originally published the Cross-State Air Pollution Rule (CSAPR) on August 8, 2011, to address interstate transport of ozone pollution under the 1997 ozone National Ambient Air Quality Standards (NAAQS).<sup>18</sup> On October 26, 2016, the EPA published the CSAPR Update, which finalized Federal Implementation Plans (FIPs) for 22 states that the EPA found failed to submit a complete good neighbor State Implementation Plan (SIP) (15 states)<sup>19</sup> or for which the EPA issued a final rule disapproving their good neighbor SIP (7 states).<sup>20</sup> The FIPs promulgated for these states included new electric generating unit (EGU) oxides of nitrogen (NO<sub>x</sub>) ozone season emission budgets to reduce interstate transport for the 2008 ozone NAAQS.<sup>21</sup> These emissions budgets took effect in 2017 in order to assist downwind states with attainment of the 2008 ozone NAAQS by the 2018 Moderate area attainment date. The EPA acknowledged at the time that the FIPs promulgated for 21 of the 22 states only partially addressed good neighbor obligations under the 2008 ozone NAAQS.<sup>22</sup>

On March 31, 2021, the EPA promulgated the Revised CSAPR Update (RCU) in response to the United States Court of Appeals for the District of Columbia Circuit’s (D.C. Circuit) September 13, 2019, remand of the CSAPR Update. The D.C. Circuit found that the CSAPR Update was unlawful to the extent it allowed those states to continue their significant contributions to downwind ozone problems beyond the statutory dates by which downwind states must demonstrate their attainment of the air quality standards. The RCU resolved 21 states’ outstanding interstate ozone transport obligations with respect to the 2008 ozone NAAQS and established a new Group 3 ozone season emissions trading program for EGUs for twelve states.

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<sup>18</sup> CSAPR also addressed interstate transport of fine particulate matter (PM<sub>2.5</sub>) under the 1997 and 2006 PM<sub>2.5</sub> NAAQS.

<sup>19</sup> Alabama, Arkansas, Illinois, Iowa, Kansas, Maryland, Michigan, Mississippi, Missouri, New Jersey, Oklahoma, Pennsylvania, Tennessee, Virginia, and West Virginia.

<sup>20</sup> Indiana, Kentucky, Louisiana, New York, Ohio, Texas, and Wisconsin.

<sup>21</sup> The 2008 ozone NAAQS is an 8-hour standard that was set at 75 parts per billion (ppb). *See* 73 FR 16436 (March 27, 2008).

<sup>22</sup> In the CSAPR Update, the EPA found that the finalized Tennessee emission budget fully addressed Tennessee’s good neighbor obligation with respect to the 2008 ozone NAAQS. As such, the number of states included was reduced from 22 to 21 states.

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As described in the preamble of this rule, to reduce interstate emission transport under the authority provided in CAA section 110(a)(2)(D)(i)(I) for the more protective 2015 ozone NAAQS, this rule further limits ozone season (May 1 through September 30) NO<sub>x</sub> emissions from EGUs in 22 states beginning in 2023 and non-EGUs in 20 states beginning in 2026 using the Interstate Transport Framework. The Interstate Transport Framework, the framework developed by the EPA in the original CSAPR, provides a 4-step process to address the requirements of the good neighbor provision for ground-level ozone and fine particulate matter (PM<sub>2.5</sub>) NAAQS: (1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (2) determining which upwind states contribute to these identified problems in amounts sufficient to “link” them to the downwind air quality problems (*i.e.*, here, a 1 percent contribution threshold); (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; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, implementing the necessary emissions reductions through enforceable measures.

#### *1.1.1 Role of Executive Orders in the Regulatory Impact Analysis*

Several statutes and executive orders apply to federal rulemakings. In accordance with Executive Orders 12866 and 13563 and the guidelines of OMB Circular A-4, the RIA analyzes the benefits and costs associated with emissions reductions for compliance with the rule. OMB Circular A-4 recommends analysis of one potential regulatory control alternative more stringent than the final rule and one less stringent than the final rule. This RIA evaluates the benefits, costs, and certain impacts of a more and a less stringent alternative to the selected alternative in this rule.

#### *1.1.2 Alternatives Analyzed*

In response to OMB Circular A-4, this RIA analyzes the Transport FIP for the 2015 ozone NAAQS emission budgets for EGUs and ozone season emissions limits for non-EGUs, as well as a more and a less stringent alternative to the final rule. For EGUs, the Transport FIP for the 2015 ozone NAAQS requires EGUs in the 22 states to participate in the CSAPR NO<sub>x</sub> Ozone

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Season Group 3 Trading Program created by the Revised CSAPR Update. For non-EGUs, the Transport FIP for the 2015 ozone NAAQS requires units subject to the rule to meet ozone season emissions limits.

The less stringent alternative differs from the Transport FIP for the 2015 ozone NAAQS in that it sets different EGU NO<sub>x</sub> ozone season emission budgets. The more stringent alternative differs from the Transport FIP for the 2015 ozone NAAQS in that it features different dates for compliance with unit-specific emission rates for the affected EGUs. The more and less stringent alternatives also ~~The more and less stringent alternatives differ from the Transport FIP for the 2015 ozone NAAQS in that they set different EGU NO<sub>x</sub> ozone season emission budgets and different dates for compliance with unit-specific emission rate limits for the affected EGUs and~~ estimate different control technologies for some emissions units for the affected non-EGUs under the assumption that they would be subject to different emission rates. Table 1-1 below presents the less stringent alternatives, final rule requirements, and more stringent alternatives for EGUs and non-EGUs.

For EGUs, one of the primary ways the final Transport FIP for the 2015 ozone NAAQS differs from the proposal is the compliance date for the backstop emission rate. At proposal, both the proposed rule and more stringent alternative imposed the backstop emission rate in 2026. The EPA continues to view the backstop emission rate as an important element of the rule to ensure the elimination of significant contribution as determined at Step 3 of the Interstate Transport Framework for all large coal units, and the rule therefore imposes this rate beginning in 2024 for units that already have SCR installed. However, in the final rule, to facilitate power sector transition planning and in response to concerns from commenters, the EPA is deferring the imposition of the backstop emissions rate for units that do not have SCR until the second ozone season following installation of the control or 2030 at the latest. The modeling of the final rule includes the backstop emission rate in the 2030 model run year and the more stringent alternative includes the backstop emission rate in the 2025 model run year (corresponding to 2026).

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

**Commented [EO 1286639]:** Suggest clarification is needed here. This is not clear from table 1-1 below. It only appears to change the backstop date from 2030 to 2025 and not modify the underlying emissions budgets.

**Commented [EPA40R39]:** The more stringent rule has the same budget as the final rule, but earlier backstop emission rate. The less stringent rule has the same backstop emission rate as the final, but a different budget. Text updated accordingly.

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controls on low-use boilers; the changes make directly comparing the alternatives analyzed between proposal and this final rule challenging. Please see Section 1.2.1 below for a more detailed discussion of the changes made and Table 1-1 below for a summary of the alternatives analyzed in the final rule.

**Table 1-1. Regulatory Control Alternatives for EGUs and Non-EGUs**

<b>Regulatory Control Alternative</b>	<b>NO<sub>x</sub> Controls Implemented for EGUs within IPM<sup>a,b</sup></b>
Less Stringent Alternative	1) 2023 onwards: Fully operate existing selective catalytic reduction (SCRs) during ozone season 2) 2023 onwards: Fully operate existing selective non-catalytic reduction (SNCRs) during ozone season 3) In 2023 install state-of-the-art combustion controls <sup>c</sup> 4) In 2030 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls. <sup>d</sup>
Final Rule	(All Controls above and) 5) In 2025 model run year, impose Engineering Analysis derived emissions budgets that assume installation of SCR controls on coal units greater than 100 MW within the 19-state region that lack SCR controls.
More Stringent Alternative	(Controls 1 – 5 above and) 6) In 2025 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls, forcing units to retrofit or retire.
<b>Regulatory Control Alternative</b>	<b>NO<sub>x</sub> Emissions Limits for Non-EGUs – Emissions Unit Types, Industries, and Controls Assumed for Compliance</b>
Less Stringent Alternative	1) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – Adjust Air-to-Fuel Ratio 2) Kilns in Cement and Cement Product Manufacturing – install SNCR 3) Reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing – install Low NO <sub>x</sub> burners (LNB) 4) Furnaces in Glass and Glass Product Manufacturing – install LNB 5) 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 – install SNCR 6) Combustors or Incinerators in Solid Waste Combustors and Incinerators – install Advanced NSCR (ANSCR) or LN <sup>TM</sup> and SNCR <sup>c</sup>
Final Rule	(Controls 2, 3, 4, and 6 above, plus changes in assumed controls noted below) 7) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – depending on engine type, install <i>Layered Combustion, non-selective catalytic reduction (NSCR), or SCR</i> 8) 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 – install <i>SCR (coal- or oil-fired) or LNB and FGR (natural gas-fired only)</i>
More Stringent Alternative	(Controls 3, 6, 7 above, plus changes in assumed controls noted below) 9) Kilns in Cement and Cement Product Manufacturing – install <i>SCR</i> 10) Furnaces in Glass and Glass Product Manufacturing – install <i>SCR</i> 11) 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 – install <i>SCR (natural gas-fired only)</i>

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<sup>a</sup> IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. For this analysis, IPM maps the calendar year 2023 to run year 2023, calendar years 2024-2026 to run year 2025 and calendar years 2027-2029 to run year 2028. For model details, please see Chapter 2 of the IPM documentation

<sup>b</sup> NO<sub>x</sub> mass budgets are imposed in all run years in IPM (2023-2050) consistent with the measures highlighted in this table.

<sup>c</sup> The final rule implementation allows for the reduction associated with state-of-the-art combustion controls to occur by 2024. It is captured in 2023 in this analysis to fully assess the impact of the mitigation measures occurring prior to 2026.

<sup>d</sup> For the 19 states with EGU obligations that are linked in 2026 the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam-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 units greater than 100 MW that have historically emitted at least 150 tons of NO<sub>x</sub> per ozone season. 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. The 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.

<sup>e</sup> Covanta has developed a proprietary low NO<sub>x</sub> combustion system (LN<sup>TM</sup>) that involves staging of combustion air. The system is a trademarked system and Covanta has received a patent for the technology.

The illustrative emission budgets in this RIA represent EGU NO<sub>x</sub> ozone season emission budgets for each state beginning in 2023.<sup>23</sup> All three scenarios use emission budgets that were developed using the selected level of uniform control stringency represented by \$1,800 per ton of NO<sub>x</sub> (2016\$) in 2023 and \$11,000 per ton of NO<sub>x</sub> (2016\$) in 2026. The final rule and less-stringent alternative scenarios defer the backstop emission rate for existing coal EGUs lacking SCR controls in the 2030 run year,<sup>24</sup> while the more stringent alternative imposes the backstop emission rate on these units in the 2025 run year (reflective of imposition in the 2026 calendar year). The backstop emission rate is imposed by these years (2025 or 2030 depending on scenario) on all coal units within the 19-state region<sup>25</sup> that are greater than 100 MW and lack

<sup>23</sup> The budget setting process is described in section VI.B. of the preamble and in detail in the Ozone Transport Policy Analysis Final Rule Technical Support Document (TSD).

<sup>24</sup> IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. For this analysis, IPM maps the calendar year 2023 to run year 2023, calendar years 2024-2026 to run year 2025 and calendar years 2027-2029 to run year 2028. For model details, please see Chapter 2 of the IPM documentation, available at: <https://www.epa.gov/system/files/documents/2021-09/epa-platform-v6-summer-2021-reference-case-09-11-21-v6.pdf>

<sup>25</sup> For the 19 states with EGU obligations that are linked in 2026 the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam-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 units greater than 100 MW that have historically emitted at least 150 tons of NO<sub>x</sub> per ozone season. 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. The 19

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SCR controls (excepting circulating fluidized bed (CFB) units). Across all three scenarios, optimization of existing controls and installation of state-of-the-art combustion controls (which reflect emission rate limits) is assumed in the 2023 run year (although the rule would not require state of the art combustion control installation until 2024).

The state emission budgets in this RIA are illustrative for several reasons. First, they reflect an estimate of the future budget based on the EPA’s preset budget methodology throughout the analytic time frame of the analysis. However, as described in the preamble, the implemented state budget may be either the preset budget or the dynamic budget starting in 2026. Second, the budgets are illustrative as the utilized 2023 preset budgets reflect full implementation of existing control optimization and upgrade to state-of-the-art combustion control potential. However, the final rule state emission budgets and implementation allows the limited number of reductions related to state-of-the-art combustion controls to be realized up through 2024. Finally, the illustrative budgets reflected in this RIA reflect budgets derived using the EPA’s data and engineering analysis up through October 2022. The preset budgets reflected in the final rule are slightly different in some cases due to new data or comment incorporation that occurred between October of 2022 and January 2023. The Agency conducted additional sensitivity analysis using IPM demonstrating that the substituting in the final preset state emission budgets instead of the illustrative ones modeled made no significant difference in the cost implications described in the body of the RIA.

For non-EGUs, the less stringent alternative assumes less stringent control technologies for the reciprocating internal combustion engines in Pipeline Transportation of Natural Gas and 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 relative to the final rule. The more stringent alternative assumes more stringent control technologies for the kilns in Cement and Concrete Products Manufacturing, the furnaces in Glass and Glass Products Manufacturing, and the natural gas fired boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and

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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.



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Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills relative to the final rule. See Section V.C. of the preamble for details on the emissions limits in the final rule.

### *1.1.3 The Need for Regulation*

OMB Circular A-4 indicates that one of the reasons a regulation may be issued is to address a market failure. The major types of market failure include externalities, market power, and inadequate or asymmetric information. Correcting market failures is one reason for regulation; it is not the only reason. Other possible justifications include improving the function of government, correcting distributional unfairness, or securing privacy or personal freedom.

Environmental problems are classic examples of externalities – uncompensated benefits or costs imposed on another party as a result of one’s actions. For example, the smoke from a factory may adversely affect the health of local residents and adversely affect the property in nearby neighborhoods. Pollution emitted in one state may be transported across state lines and affect air quality in a neighboring state.

From an economics perspective, achieving emissions reductions (i.e., by establishing the EGU NO<sub>x</sub> ozone-season emissions budgets in this rule) through a market-based mechanism is a straightforward and cost-effective remedy to address an externality in which firms emit pollutants, resulting in health and environmental problems without compensation for those incurring the problems. Capping emissions through allowance allocations incentivizes those who emit the pollutants to reduce their emissions, which lessens the impact on those who suffer the health and environmental problems from higher levels of pollution. In addition, emissions rates for non-EGU sources work toward addressing this market failure by requiring affected facilities to reduce NO<sub>x</sub> emissions.

## **1.2 Overview and Design of the RIA**

### *1.2.1 Methodology for Identifying Needed Reductions*

To apply the first and second steps of the CSAPR 4-step Interstate Transport Framework to interstate transport for the 2015 ozone NAAQS, the EPA performed air quality modeling to project ozone concentrations at air quality monitoring sites in 2023 and 2026. The EPA evaluated projected ozone concentrations for the 2023 analytic year at individual monitoring

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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 was then repeated using projected ozone concentrations for 2026. In these analyses, downwind air quality problems are defined by receptors that are projected to be unable to attain (i.e., nonattainment receptor) or maintain (i.e., maintenance receptor) the 2015 ozone NAAQS.<sup>26</sup>

To apply the second step of the Interstate Transport Framework, the EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2023 and 2026 at downwind receptors. Once quantified, the EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS. States with contributions that equal or exceed 1 percent of the NAAQS are identified as warranting further analysis for significant contribution to nonattainment or interference with maintenance.<sup>27</sup> States with contributions below 1 percent of the NAAQS are considered to not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states.

To apply the third step of the Interstate Transport Framework, the EPA applied a multi-factor test to evaluate cost, available emissions reductions, and downwind air quality impacts to determine the appropriate level of NO<sub>x</sub> control stringency that addresses the impacts of interstate transport on downwind nonattainment or maintenance receptors. The EPA used this multi-factor assessment to gauge the extent to which emissions reductions are needed, and to ensure any required reductions do not result in over-control.

For EGUs, in identifying levels of uniform control stringency the EPA assessed the same NO<sub>x</sub> emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available for EGUs: (1) fully operating existing SCR, including both optimizing NO<sub>x</sub> removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO<sub>x</sub> combustion controls; (3) fully operating existing SNCRs, including both optimizing NO<sub>x</sub> removal by existing

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<sup>26</sup> See Section IV.D of the preamble for a full discussion of the final rule's approach to receptor identification, including the consideration of "violating monitor" maintenance-only receptors.

<sup>27</sup> The EPA assessed the magnitude of the maximum projected design value for 2023 at each receptor in relation to the 2015 ozone NAAQS. Where the value exceeds the NAAQS, the EPA determined that receptor to be a maintenance receptor for purposes of defining interference with maintenance. That is, monitoring sites with a maximum design value that exceeds the NAAQS are projected to have a maintenance problem in 2023.

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operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting (i.e., emission reductions anticipated to occur from generation shifting from higher to lower emitting units). The selected levels of uniform control stringency were represented by \$1,800 per ton of NO<sub>x</sub> (2016\$) in 2023 and \$11,000 per ton of NO<sub>x</sub> (2016\$) in 2026.<sup>28</sup>

For non-EGUs, the EPA developed an analytical framework to determine which industries and emission 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.<sup>29</sup> To further evaluate the industries and emissions unit types identified and to establish the 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 state implementation plan (SIP) submittals, consent decrees, and permit limits. That evaluation is detailed in the *Non-EGU Sectors Technical Support Document (TSD)* prepared for the proposed FIP.<sup>30</sup> The EPA is retaining the industries and many of the emissions unit types included in the proposal in this final action. For a discussion of changes to emissions limits between the proposed FIP and the final rule, see Section V.C of the preamble to the final rule and the Final Non-EGU Sectors TSD.

Below is a summary of the adjustments and additions to the emissions limits for non-EGUs the EPA made between the proposed FIP and this final rule.

- For Pipeline Transportation of Natural Gas, the EPA is finalizing the same emissions limits as proposed; however, the EPA is adjusting the applicability criteria to exclude emergency engines. Further, to allow for the industry to install controls on the engines with the largest potential for emissions reductions at cost-effective

<sup>28</sup> EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD, in the docket for this rule (Docket ID No. EPA-HQ-OAR-2021-0688).

<sup>29</sup> The memorandum is available in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150>.

<sup>30</sup> The TSD is available in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145>.

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thresholds, the final regulations allow for the use of facility-wide emissions averaging for engines in the industry.

- For Cement and Concrete Product Manufacturing, in the final rule the EPA has removed the daily source cap limit, which could have resulted in an artificially restrictive NO<sub>x</sub> emissions limit for affected cement kilns due to lower operating periods resulting from to the COVID-19 pandemic.
- For Iron and Steel and Ferroalloy Manufacturing, the EPA is only finalizing a test-and-set requirement for reheat furnaces premised on the installation of low-NO<sub>x</sub> burners. By not finalizing the other proposed emissions limits that were likely to require the installation of SCR, the EPA has addressed the various concerns regarding the feasibility and cost-effectiveness of installation of the other proposed controls at other unit types 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 Iron and Steel and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills, the EPA is finalizing a low-use exemption to eliminate the need to install controls on low-use boilers that would have resulted in relatively small reductions.
- For municipal waste combustors in Solid Waste Combustors and Incinerators, the EPA is finalizing emissions limits, summarized in Table ES-1.

For the final rule, to determine NO<sub>x</sub> emissions reduction potential for the 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 for MWCs using the 2019 inventory, as well as the NEEDS-v6-summer-2021-reference-case workbook.<sup>31</sup> Based on the review of RACT, NSPS, NESHAP rules, as well as SIPs, consent decrees, and permits, we also assumed certain

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<sup>31</sup> Available here: <https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6>.

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control technologies could meet the final emissions limits.<sup>32</sup> Rather than run the Control Strategy Tool to estimate emissions reductions and costs, we programmed the assessment using R to estimate NO<sub>x</sub> emission reductions and their costs.<sup>33</sup> Specifically, 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 (CMDDB),<sup>34</sup> the EPA estimated NO<sub>x</sub> emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. 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.

#### 1.2.2 States Covered by the Rule

For EGUs, the Transport FIP for the 2015 ozone NAAQS requires EGUs in 22 states to participate in the CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program created by the Revised CSAPR Update.<sup>35</sup>

- The following twelve states currently participating in the Group 3 Trading Program would 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 in seven states currently covered by the CSAPR NO<sub>x</sub> Ozone Season Group 2 Trading Program – Alabama, Arkansas, Mississippi, Missouri,

<sup>32</sup> The Technical Support Document (TSD) for the Final Rule, Non-EGU Sectors TSD is available in the docket.

<sup>33</sup> R is a free software environment for statistical computing and graphics. Additional information is available here: <https://www.r-project.org/>. The R code that processed the data to estimate the emissions reductions and costs is available upon request.

<sup>34</sup> More information about the Control Strategy Tool (CoST) and the control measures database (CMDDB) can be found at the following link: <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution>.

<sup>35</sup> As explained in Section V.C.1 of the preamble, the EPA finds 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.

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Oklahoma, Texas, and Wisconsin – would transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period.

- Affected EGUs in three states not currently covered by any CSAPR trading program for seasonal NO<sub>x</sub> emissions – Minnesota, Nevada, and Utah – would enter the Group 3 trading program in the 2023 control period following the effective date of this final rule.

In addition, the EPA is revising other aspects of the Group 3 trading program to provide improved environmental outcomes and increase compliance, as described in Section VI of the preamble. Revisions include dynamic adjustments of the emissions budgets over time and a backstop daily emission rate for most coal-fired units, along with an adjustment to the total size of the allowance bank. The final rule does not revise the budget stringency and geography of the existing CSAPR NO<sub>x</sub> 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 rule, this action otherwise leaves unchanged the budget stringency of the existing CSAPR NO<sub>x</sub> Ozone Season Group 2 trading program.

For non-EGUs, the rule includes NO<sub>x</sub> emissions limitations with an initial compliance date of May 1, 2026, applicable to certain non-EGU stationary 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.

### *1.2.3 Regulated Entities*

The rule affects EGUs in 22 states that have a nameplate capacity of greater than 25 megawatts (MWe), which generally fall in 22 states within the utility sector (electric, natural gas, other systems) classified as code 221112 by the North American Industry Classification System (NAICS). In addition, the rule affects certain non-EGUs in 20 states in the following industries, as defined by 4- or 6-digit NAICS: Pipeline Transportation of Natural Gas, 4862; Cement and Concrete Product Manufacturing, 3273; Iron and Steel Mills and Ferroalloy Manufacturing, 3311; Glass and Glass Product Manufacturing, 3272; Metal Ore Mining, 2122; Basic Chemical

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Manufacturing, 3251; Petroleum and Coal Products Manufacturing, 3241; Pulp, Paper, and Paperboard Mills, 3221; Solid Waste Combustors and Incinerators, 562213. For additional discussion of the non-EGUs affected, see Section V.C. of the preamble.

#### *1.2.4 Baseline and Analysis Years*

As described in the preamble, the EPA aligns implementation of this rule with relevant attainment dates for the 2015 ozone NAAQS. The rule requires emissions reductions 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 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 final rule will allow individual facilities limited additional time to fully implement the required emissions reductions. 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, the 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. More information regarding the timing elements of the rule can be found in Section VI.A of the preamble.

To develop and evaluate control strategies for addressing these obligations, it is important to first establish a baseline projection of air quality in the analysis years of 2023 and 2026, taking into account currently on-the-books Federal regulations, enforcement actions, state regulations, population, and where possible, economic growth.<sup>36</sup> Establishing this baseline for the analysis then allows us to estimate the incremental costs and benefits of the additional emissions

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<sup>36</sup> The technical support document (TSD) for the 2016v2 emissions modeling platform titled *Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform* is included in the docket for this rule. The TSD includes additional discussion on mobile source rules included in the baseline.

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reductions that will be achieved by the rule. Federal rules included in the baseline are: the Revised Cross-State Air Pollution Rule (CSAPR) Update, the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources, Reciprocating Internal Combustion Engine (RICE) New Source Performance Standards (NSPS), Natural gas turbines NSPS, Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles – Phase 2, and 2017 and Later Model Year Light-Duty Vehicle GHG Emissions and Corporate Average Fuel Economy Standards.

The analysis in this RIA focuses on benefits, costs and certain impacts from 2023 through 2042. We focus on 2023 because it is by the 2023 ozone season, corresponding with the 2024 attainment date for areas classified as Moderate nonattainment, that significant contribution from upwind states' must be eliminated to the extent possible. In addition, impacts for 2026 are important because this ozone season corresponds with the 2027 Serious area attainment date and it is by this ozone season that additional requirements for NOx emissions reductions for EGUs and non-EGUs begin to apply for states whose upwind linkage to downwind receptors persists. The EPA's analysis for the third step of the Interstate Transport Framework reflects emissions reductions for 2023 from EGUs based on a control stringency at a representative cost threshold of \$1,800 per ton. Those reductions are commensurate with optimization of existing SCRs and SNCRs and installation of state-of-the-art combustion controls. For 2026, the selected control stringency (at a representative cost per ton threshold for EGUs of \$11,000 and an overall estimated average cost per ton for non-EGUs of \$5,339/ton (2106\$), with average cost by industry ranging from \$939/ton to \$14,595/ton) includes additional EGU controls and estimated non-EGU emissions reductions. See Section V.D of the preamble for additional discussion. Additional benefits and costs are expected to occur after 2026 as EGUs subject to this rule continue to comply with the tighter allowance budget, which is below their baseline emissions, and non-EGUs remain subject to ozone season emissions limits.

The Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (IRA) includes significant additional new generation incentives targeting more efficient and lower-emitting sources of generation that is likely to meaningfully affect the US generation mix in the future and increase the pace of new lower-emitting generation replacing some of older higher-emitting generating capacity.



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In addition, we include an appendix to Chapter 4 to describe the EGU compliance behavior, costs, and emissions reductions that include adjustments made to the IPM baseline to account for the potential effects of the IRA of 2022 on the power sector costs, emission reductions, and other impacts from this final rule. This supplementary analysis quantifies the incremental impacts of the Transport FIP for the 2015 ozone NAAQS under this alternative baseline characterization and compares impacts to the main analyses in Chapter 4. As described in Chapter 4, the power sector analyses that inform air quality modeling in subsequent chapters in this RIA do not include the IRA due to time limitations. However, in the interests of completeness the appendix seeks to quantify the impacts of the IRA on the analyses of power sector impacts of the final rule.

#### *1.2.5 Emissions Controls, Emissions, and Cost Analysis Approach*

The EPA estimated the effects of the EGU control strategies in the final rule, including their projected compliance costs, using the Integrated Planning Model (IPM), as well as certain costs that are estimated outside the model but use IPM inputs for their estimation. These cost estimates reflect costs incurred by the power sector and include (but are not limited to) the costs of purchasing, installing, and operating NO<sub>x</sub> control technology, changes in fuel costs, and changes in the generation mix. A description of the methodologies used to estimate the costs and economic impacts to the power sector is contained in Chapter 4 of this RIA. This analysis also provides estimates of NO<sub>x</sub> emissions changes during the May through September ozone season and year-round, as well as annual emissions changes in PM<sub>2.5</sub>, SO<sub>2</sub>, and carbon dioxide (CO<sub>2</sub>) due to changes in power sector operation.

As described in Section 1.2.1 for non-EGUs, to determine NO<sub>x</sub> emissions reduction potential for the industries and emissions unit types, except for 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 and programmed the assessment's estimated emission reductions and costs using R.<sup>37</sup> For Solid

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<sup>37</sup> R is a free software environment for statistical computing and graphics. Additional information is available here: <https://www.r-project.org/>. The R code that processed the data to estimate the emissions reductions and costs is available upon request.

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Waste Combustors and Incinerators, the EPA estimated the list for MWCs using the 2019 inventory, as well as the NEEDS-v6-summer-2021-reference-case workbook. The EPA did not run the Control Strategy Tool (CoST) to estimate emissions reductions.

Using 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 (CMDB),<sup>38,39</sup> the EPA estimated NO<sub>x</sub> emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. The EPA did not estimate emissions reductions of SO<sub>2</sub>, PM<sub>2.5</sub>, CO<sub>2</sub> and other pollutants that may be associated with controls on non-EGU emissions units. 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.

#### 1.2.6 Benefits Analysis Approach

Implementing the Transport FIP for the 2015 ozone NAAQS is expected to reduce emissions of PM<sub>2.5</sub>, NO<sub>x</sub> and SO<sub>2</sub> throughout the year. Because NO<sub>x</sub> and SO<sub>2</sub> are also precursors to formation of ambient PM<sub>2.5</sub>, reducing these emissions would reduce human exposure to ambient PM<sub>2.5</sub> throughout the year and would reduce the incidence of PM<sub>2.5</sub>-attributable health

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<sup>38</sup> 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>.

<sup>39</sup> 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 be different than those estimated in this assessment; the estimated emissions reductions from and costs to meet the final rule emissions limits may be different than those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

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effects. In addition, we estimate the climate benefits of CO<sub>2</sub> emissions reductions expected from this final rule using the SC-CO<sub>2</sub> estimates.

### 1.3 Organization of the Regulatory Impact Analysis

This RIA is organized into the following remaining chapters:

- *Chapter 2: Industry Sector Profiles.* This chapter describes the electric power sector in detail, as well as provides an overview of the other non-EGU industries.
- *Chapter 3: Air Quality Impacts.* The data, tools, and methodology used for the air quality modeling are described in this chapter, as well as the post-processing techniques used to produce air quality metric values for input into the analysis of benefits and costs.
- *Chapter 4: Cost, Emissions, and Energy Impacts.* The chapter summarizes the data sources and methodology used to estimate the costs and other impacts incurred by the power sector. The chapter summarizes the non-EGU assessment used to estimate emissions reductions and costs for the non-EGU industries.
- *Chapter 5: Benefits.* The chapter presents the health-related benefits of the ozone and PM related air quality improvements and the climate benefits of CO<sub>2</sub> emissions reductions.
- *Chapter 6: Economic Impacts.* The chapter includes a discussion of small entity, economic, and labor impacts.
- *Chapter 7: Environmental Justice Impacts.* This chapter includes an assessment of downwind ozone impacts across communities with potential environmental justice concerns.
- *Chapter 8: Comparison of Benefits and Costs.* The chapter compares estimates of the total benefits with total costs and summarizes the net benefits of the three regulatory control alternatives analyzed.

## **CHAPTER 2: INDUSTRY SECTOR PROFILES**

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### **Overview**

This chapter discusses important aspects of the regulated industries that relate to the final rule with respect to the interstate transport of emissions of nitrogen oxides (NO<sub>x</sub>) that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in downwind states. This chapter describes types of existing power-sector sources affected by the regulation and provides background on the power sector and electricity generating units (EGUs). In addition, this chapter also briefly describes the relevant non-EGU industries included in the regulation.

### **2.1 Background**

In the past decade there have been significant structural changes in both the mix of generating capacity and in the share of electricity generation supplied by different types of generation. These changes are the result of multiple factors in the power sector, including normal replacements of older generating units with new units, changes in the electricity intensity of the U.S. economy, growth and regional changes in the U.S. population, technological improvements in electricity generation from both existing and new units, changes in the prices and availability of different fuels, and substantial growth in electricity generation by renewable and unconventional methods. Many of these trends will continue to contribute to the evolution of the power sector. The evolving economics of the power sector, specifically the increased natural gas supply and subsequent relatively low natural gas prices, have resulted in more natural gas being used as base load energy in addition to supplying electricity during peak load. Additionally rapid growth in the penetration of renewables has led to their now constituting a significant share of generation. This chapter presents data on the evolution of the power sector from 2014 through 2021. Projections of future power sector behavior and the impact of this proposed rule are discussed in more detail in Chapter 4 of this RIA.

### **2.2 Power Sector Overview**

The production and delivery of electricity to customers consists of three distinct segments: generation, transmission, and distribution.

### 2.2.1 Generation

Electricity generation is the first process in the delivery of electricity to consumers. There are two important aspects of electricity generation: capacity and net generation. *Generating Capacity* refers to the maximum amount of production an EGU is capable of producing in a typical hour, typically measured in megawatts (MW) for individual units, or gigawatts (1 GW = 1,000 MW) for multiple EGUs. *Electricity Generation* refers to the amount of electricity actually produced by an EGU over some period of time, measured in kilowatt-hours (kWh) or gigawatt-hours (1 GWh = 1 million kWh). Net Generation is the amount of electricity that is available to the grid from the EGU (i.e., excluding the amount of electricity generated but used within the generating station for operations). Electricity generation is most often reported as the total annual generation (or some other period, such as seasonal). In addition to producing electricity for sale to the grid, EGUs perform other services important to reliable electricity supply, such as providing backup generating capacity in the event of unexpected changes in demand or unexpected changes in the availability of other generators. Other important services provided by generators include facilitating the regulation of the voltage of supplied generation.

Individual EGUs are not used to generate electricity 100 percent of the time. Individual EGUs are periodically not needed to meet the regular daily and seasonal fluctuations of electricity demand. Furthermore, EGUs relying on renewable resources such as wind, sunlight and surface water to generate electricity are routinely constrained by the availability of adequate wind, sunlight, or water at different times of the day and season. Units are also unavailable during routine and unanticipated outages for maintenance. These factors result in the mix of generating capacity types available (e.g., the share of capacity of each type of EGU) being substantially different than the mix of the share of total electricity produced by each type of EGU in a given season or year.

Most of the existing capacity generates electricity by creating heat to create high pressure steam that is released to rotate turbines which, in turn, create electricity. Natural gas combined cycle (NGCC) units have two generating components operating from a single source of heat. The first cycle is a gas-fired turbine, which generates electricity directly from the heat of burning natural gas. The second cycle reuses the waste heat from the first cycle to generate steam, which is then used to generate electricity from a steam turbine. Other EGUs generate electricity by

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using water or wind to rotate turbines, and a variety of other methods including direct photovoltaic generation also make up a small, but growing, share of the overall electricity supply. The generating capacity includes fossil-fuel-fired units, nuclear units, and hydroelectric and other renewable sources (see Table 2-1). Table 2-1 also shows the comparison between the generating capacity over 2015-2021.

In 2021 the power sector comprised a total capacity<sup>40</sup> of 1,179 GW, an increase of 105 GW (or 10 percent) from the capacity in 2015 (1,074 GW). The largest change over this period was the decline of 70 GW of coal capacity, reflecting the retirement/rerating of over a third of the coal fleet. This reduction in coal capacity was offset by an increase in natural gas capacity of 52 GW, and an increase in solar (48 GW) and wind (60 GW) capacity over the same period. Additionally, significant amounts of distributed solar (23 GW) were also added.

**Table 2-1. Total Net Summer Electricity Generating Capacity by Energy Source, 2014 and 2021**

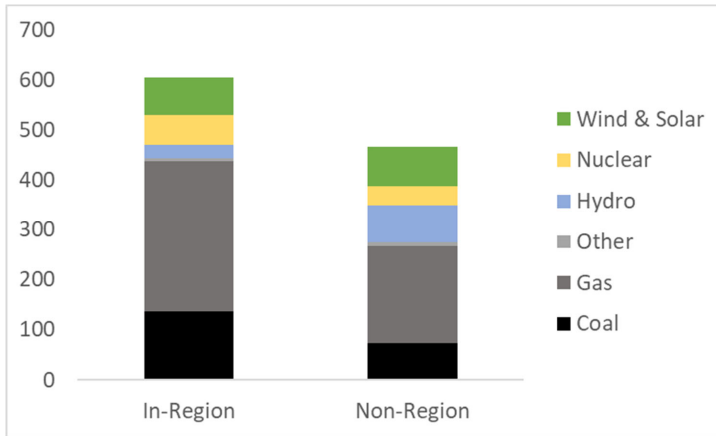
Energy Source	2015		2021		Change Between '15 and '21	
	Net Summer Capacity (GW)	% Total Capacity	Net Summer Capacity (GW)	% Total Capacity	% Increase	Capacity Change (GW)
Coal	280	26%	210	18%	-25%	-70
Natural Gas	439	41%	492	42%	12%	52
Nuclear	99	9%	96	8%	-3%	-3
Hydro	102	10%	103	9%	1%	1
Petroleum	37	3%	28	2%	-23%	-9
Wind	73	7%	133	11%	83%	60
Solar	14	1%	62	5%	350%	48
Distributed Solar	10	1%	33	3%	238%	23
Other Renewable	17	2%	15	1%	-10%	-2
Misc	4	0%	8	1%	91%	4
Total	1,074	100%	1,179	100%	10%	105

Note: This table presents generation capacity. Actual net generation is presented in Table 2-2.  
 Source: EIA. Electric Power Annual 2022, Tables 4.2

<sup>40</sup> This includes generating capacity at EGUs primarily operated to supply electricity to the grid and combined heat and power facilities classified as Independent Power Producers (IPP) and excludes generating capacity at commercial and industrial facilities that does not operate primarily as an EGU. Natural Gas information in this chapter (unless otherwise stated) reflects data for all generating units using natural gas as the primary fossil heat source. This includes Combined Cycle Combustion Turbine, Gas Turbine, steam, and miscellaneous (< 1 percent).

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The information in Table 2-1 presents information about the generating capacity in the entire U.S. The Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS), however, directly affects EGUs in 22 eastern states. The share of generating capacity from each major type of generation differs between the FIP for the 2015 NAAQS Ozone Region and the rest of the U.S. (non-region). Figure 2-1 shows the mix of generating capacity for each region. In 2021, the overall capacity in the Transport FIP for the 2015 Ozone NAAQS Region is 56 percent of the national total, reflecting the larger total population in the region. The mix of capacity is noticeably different in the two regions. In the Transport FIP for the 2015 Ozone NAAQS Region in 2020, coal makes up a significantly larger share of total capacity (23 percent) than it does in the rest of the country (16 percent). The share of natural gas in the Transport FIP for the 2015 Ozone NAAQS Region is 50 percent as compared to 41 percent in the rest of the country. The difference in the share of coal’s capacity is primarily balanced by relatively more hydro, wind, and solar capacity in the rest of country compared to the Transport FIP for the 2015 Ozone NAAQS Region.



**Figure 2-1. Regional Differences in Generating Capacity (GW), 2021**  
Source: NEEDSv6.21

In 2021, electric generating sources produced a net 4,157 TWh to meet national electricity demand, which was around 2% higher than 2015. As presented in Table 2-2, 59 percent of electricity in 2021 was produced through the combustion of fossil fuels, primarily coal

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and natural gas, with natural gas accounting for the largest single share. The total generation share from fossil fuels in 2021 (60%) was 11% less than the share in 2010 (69%). Moreover, the share of fossil generation supplied by coal fell from 65% in 2010 to 36% by 2021, while the share of fossil generation supplied by natural gas rose from 35% to 64% over the same period. In absolute terms, coal generation declined by 51 percent, while natural gas generation increased by 60 percent. This reflects both the increase in natural gas capacity during that period as well as an increase in the utilization of new and existing gas EGUs during that period. The combination of wind and solar generation also grew from 2 percent of the mix in 2010 to 13 percent in 2021.

**Table 2-2. Net Generation in 2015 and 2021 (Trillion kWh = TWh)**

Energy Source	2015		2021		Change Between '15 and '21	
	Net Generation (TWh)	Fuel Source Share	Net Generation (TWh)	Fuel Source Share	% Increase	Generation Change (TWh)
Coal	1,352	33%	898	22%	-34%	-455
Natural Gas	1,333	33%	1,579	38%	18%	246
Nuclear	797	19%	778	19%	-2%	-19
Hydro	244	6%	246	6%	1%	2
Petroleum	28	1%	19	0%	-32%	-9
Wind	191	5%	378	9%	98%	187
Solar	25	1%	115	3%	363%	90
Distributed Solar	14	0%	49	1%	248%	35
Other Renewable	80	2%	70	2%	-12%	-9
Misc	27	1%	24	1%	-13%	-4
Total	4,092	100%	4,157	100%	2%	66

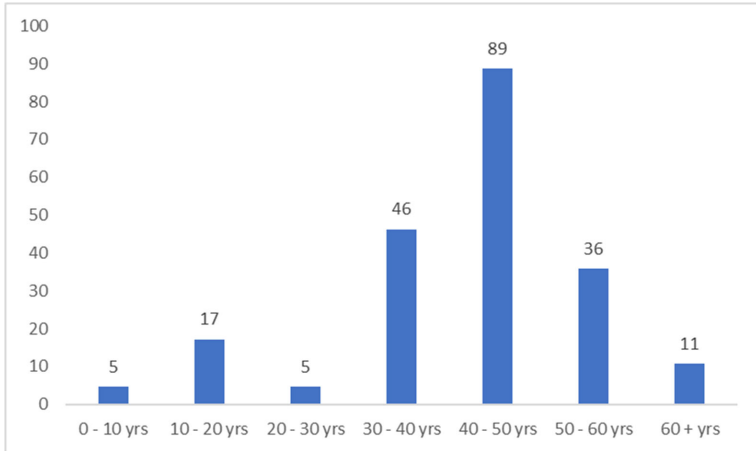
Source: EIA. Electric Power Annual 2022, Tables 3.2

The average age of coal-fired power plants that have retired between 2015 and 2021 is over 50 years. Older power plants tend to become uneconomic over time as they become more costly to maintain and operate, and as newer and more efficient alternative generating technologies are built. As a result, coal’s share of total U.S. electricity generation has been declining for over a decade, while generation from natural gas and renewables has increased



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significantly.<sup>41</sup> As shown in Figure 2-2 below, 65% of the coal fleet in 2021 had an average age of over 40 years.



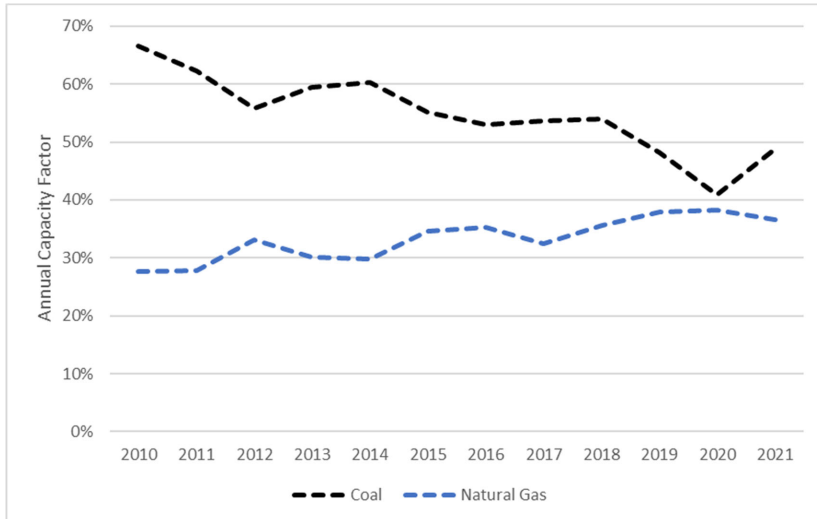
**Figure 2-2. National Coal-fired Capacity (GW) by Age of EGU, 2021**

Source: NEEDS v6

Coal-fired and nuclear generating units have historically supplied “base load” electricity, the portion of electricity loads that are continually present and typically operate throughout all hours of the year. Although much of the coal fleet has historically operated as base load, there can be notable differences across various facilities (see Table 2-3). For example, coal-fired units less than 100 megawatts (MW) in size comprise 18 percent of the total number of coal-fired units, but only 2 percent of total coal-fired capacity. Gas-fired generation is better able to vary output and is the primary option used to meet the variable portion of the electricity load and has historically supplied “peak” and “intermediate” power, when there is increased demand for electricity (for example, when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning), versus late at night or very early in the morning, when demand for electricity is reduced. Moreover, as shown in Figure 2-3, average annual coal capacity factors have declined from 67% to 49% over the 2010-2021 period, indicating that a larger share of units are operating in non-baseload fashion. Over the same period, natural gas capacity factors have risen from an annual average of 28% to 37%.

<sup>41</sup> EIA, Today in Energy (April 17, 2017) available at <https://www.eia.gov/todayinenergy/detail.php?id=30812>

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**Figure 2-3. Average Annual Capacity Factor by Energy Source**

Source: EIA. Electric Power Annual 2022, Tables 3.2 and 4.2

Table 2-3 also shows comparable data for the capacity and age distribution of natural gas units. Compared with the fleet of coal EGUs, the natural gas fleet of EGUs is generally smaller and newer. While 67 percent of the coal EGU fleet capacity is over 500 MW per unit, 75 percent of the gas fleet is between 50 and 500 MW per unit.

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**Table 2-3. Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Average Heat Rate in 2020**

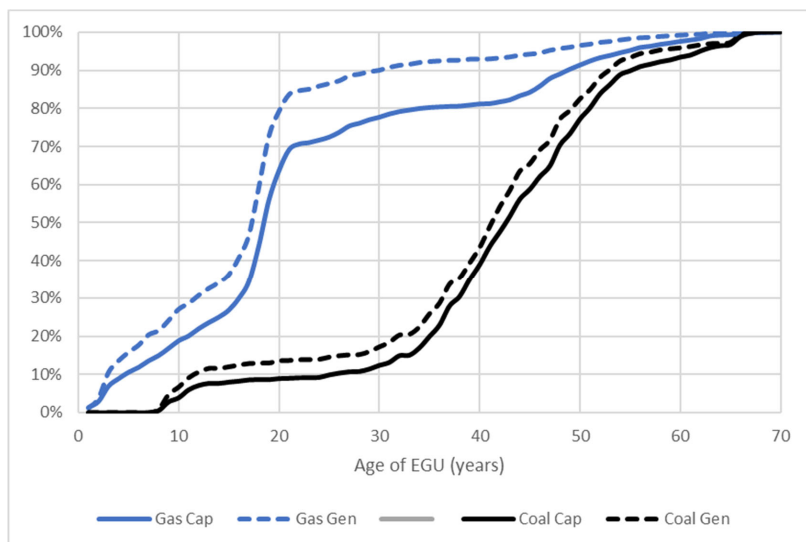
Unit Size Grouping (MW)	No. Units	% of All Units	Avg. Age	Avg. Net Summer Capacity (MW)	Total Net Summer Capacity (MW)	% Total Capacity	Avg. Heat Rate (Btu/kWh)
<b>COAL</b>							
0 – 24	31	6%	49	11	351	0%	11,379
25 – 49	32	6%	35	36	1,150	1%	11,541
50 – 99	24	5%	39	76	1,823	1%	11,649
100 – 149	36	7%	50	122	4,388	2%	11,167
150 – 249	61	12%	52	197	12,027	6%	10,910
250 – 499	132	26%	42	372	49,090	24%	10,700
500 – 749	138	27%	41	609	83,978	40%	10,315
750 – 999	50	10%	38	827	41,345	20%	10,135
1000 – 1500	11	2%	43	1,264	13,903	7%	9,834
Total Coal	515	100%	43	404	208,056	100%	10,718
<b>NATURAL GAS</b>							
0 – 24	4,329	54%	31	5	21,626	4%	13,244
25 – 49	932	12%	26	41	38,089	8%	11,759
50 – 99	1,018	13%	27	71	72,744	15%	12,163
100 – 149	410	5%	23	126	51,567	10%	9,447
150 – 249	1,041	13%	18	179	186,494	37%	8,226
250 – 499	293	4%	21	332	97,244	19%	8,293
500 – 749	37	0%	38	592	21,910	4%	10,384
750 – 999	10	0%	46	828	8,278	2%	11,294
1000 – 1500	1	0%	0	1,060	1,060	0%	7,050
Total Gas	8,060	100%	28	62	499,012	100%	11,900

Source: National Electric Energy Data System (NEEDS) v.6

Note: The average heat rate reported is the mean of the heat rate of the units in each size category (as opposed to a generation-weighted or capacity-weighted average heat rate.) A lower heat rate indicates a higher level of fuel efficiency.

In terms of the age of the generating units, almost 50 percent of the total coal generating capacity has been in service for more than 40 years, while nearly 50 percent of the natural gas capacity has been in service less than 15 years. Figure 2-4 presents the cumulative age distributions of the coal and gas fleets, highlighting the pronounced differences in the ages of the fleets of these two types of fossil-fuel generating capacity. Figure 2-4 also includes the distribution of generation, which is similar to the distribution of capacity.

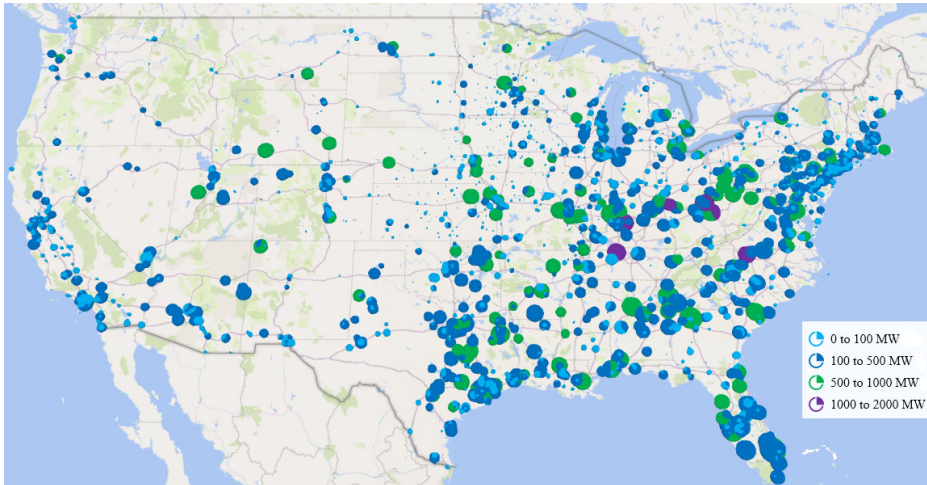
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**Figure 2-4. Cumulative Distribution in 2019 of Coal and Natural Gas Electricity Capacity and Generation, by Age**

Source: eGRID 2020 (January 2022 release from EPA eGRID website). Figure presents data from generators that came online between 1950 and 2020 (inclusive); a 71-year period. Full eGrid data includes generators that came online as far back as 1915. Full data from 1915 onward is used in calculating cumulative distributions; figure truncation at 70 years is merely to improve visibility of diagram.

The locations of existing fossil units in EPA’s National Electric Energy Data System (NEEDS) v.6 are shown in Figure 2-5.



**Figure 2-5. Fossil Fuel-Fired Electricity Generating Facilities, by Size**

Source: National Electric Energy Data System (NEEDS) v.6

Note: This map displays fossil capacity at facilities in the NEEDS v.6 IPM frame. NEEDS v.6 reflects generating capacity expected to be on-line at the end of 2023. This includes planned new builds already under construction and planned retirements. In areas with a dense concentration of facilities, some facilities may be obscured.

### 2.2.2 Transmission

Transmission is the term used to describe the bulk transfer of electricity over a network of high voltage lines, from electric generators to substations where power is stepped down for local distribution. In the U.S. and Canada, there are three separate interconnected networks of high voltage transmission lines,<sup>42</sup> each operating synchronously. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator;<sup>43</sup> in others, individual utilities<sup>44</sup> coordinate the operations of their generation,

<sup>42</sup> These three network interconnections are the Western Interconnection, comprising the western parts of both the US and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the US and Canada (except those part of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at <https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf>.

<sup>43</sup> For example, PMJ Interconnection, LLC, Western Area Power Administration (which comprises 4 sub-regions).

<sup>44</sup> For example, Los Angeles Department of Power and Water, Florida Power and Light.

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transmission, and distribution systems to balance the system across their respective service territories.

### *2.2.3 Distribution*

Distribution of electricity involves networks of lower voltage lines and substations that take the higher voltage power from the transmission system and step it down to lower voltage levels to match the needs of customers. The transmission and distribution system is the classic example of a natural monopoly, in part because it is not practical to have more than one set of lines running from the electricity generating sources to substations or from substations to residences and businesses.

Over the last few decades, several jurisdictions in the United States began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, vertically integrated utilities established much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission utilities, electric cooperatives, and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by a number of utilities that purchase and sell electricity, but do not generate it. As discussed below, electricity restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission and distribution services needed to deliver power to consumers. In many states, such efforts have also included separating generation assets from transmission and distribution assets to form distinct economic entities. Transmission and distribution remain price-regulated throughout the country based on the cost of service.

## **2.3 Sales, Expenses, and Prices**

These electric generating sources provide electricity for ultimate commercial, industrial and residential customers. Each of the three major ultimate categories consume roughly a quarter to a third of the total electricity produced<sup>45</sup> (see Table 2-4). Some of these uses are highly

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<sup>45</sup> Transportation (primarily urban and regional electrical trains) is a fourth ultimate customer category which accounts less than one percent of electricity consumption.

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variable, such as heating and air conditioning in residential and commercial buildings, while others are relatively constant, such as industrial processes that operate 24 hours a day. The distribution between the end use categories changed very little between 2015 and 2021.

**Table 2-4. Total U.S. Electric Power Industry Retail Sales, 2015 and 2021 (billion kWh)**

		2015		2021	
		Sales/Direct Use (Billion kWh)	Share of Total End Use	Sales/Direct Use (Billion kWh)	Share of Total End Use
<b>Sales</b>	Residential	1,404	36%	1,470	37%
	Commercial	1,361	35%	1,328	34%
	Industrial	987	25%	1,001	25%
	Transportation	8	0%	6	0%
<b>Total</b>		3,759	96%	3,806	96%
<b>Direct Use</b>			141	4%	139
<b>Total End Use</b>			<b>3,900</b>	<b>100%</b>	<b>3,945</b>

Source: Table 2.2, EIA Electric Power Annual, 2021

Notes: Retail sales are not equal to net generation (Table 2-2) because net generation includes net imported electricity and loss of electricity that occurs through transmission and distribution, along with data collection frame differences and non-sampling error. Direct Use represents commercial and industrial facility use of onsite net electricity generation; electricity sales or transfers to adjacent or co-located facilities; and barter transactions.

### 2.3.1 Electricity Prices

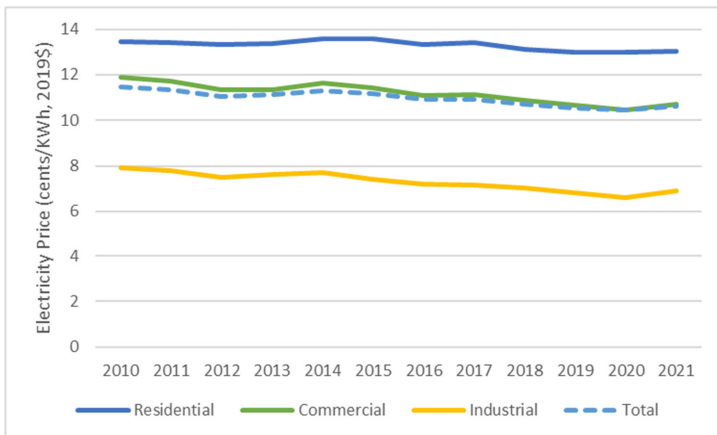
Electricity prices vary substantially across the United States, differing both between the ultimate customer categories and by state and region of the country. Electricity prices are typically highest for residential and commercial customers because of the relatively high costs of distributing electricity to individual homes and commercial establishments. The higher prices for residential and commercial customers are the result both of the necessary extensive distribution network reaching to virtually every part of the country and every building, and also the fact that generating stations are increasingly located relatively far from population centers (which increases transmission costs). Industrial customers generally pay the lowest average prices, reflecting both their proximity to generating stations and the fact that industrial customers receive electricity at higher voltages (which makes transmission more efficient and less expensive). Industrial customers frequently pay variable prices for electricity, varying by the season and time of day, while residential and commercial prices historically have been less

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variable. Overall industrial customer prices are usually considerably closer to the wholesale marginal cost of generating electricity than residential and commercial prices.

On a state-by-state basis, all retail electricity prices vary considerably. In 2021, the national average retail electricity price (all sectors) was 11.18 cents/KWh, with a range from 7.5 cents (Louisiana) to 27 cents (Hawaii).<sup>46</sup>

Average national retail electricity prices decreased between 2010 and 2021 by 8 percent in real terms (2019\$), and 5% between 2015-21.<sup>47</sup> The amount of decrease differed for the three major end use categories (residential, commercial and industrial). National average industrial prices decreased the most (7 percent), and residential prices decreased the least (4 percent) between 2015-21. The real year prices for 2010 through 2021 are shown in Figure 2-6.



**Figure 2-6. Real National Average Electricity Prices (including taxes) for Three Major End-Use Categories**

Source: EIA. Electric Power Annual 2021, Table 2.4.

Most of these electricity price decreases occurred between 2014 and 2015, when nominal residential electricity prices followed inflation trends, while nominal commercial and industrial electricity prices declined. The years 2016 and 2017 saw an increase in nominal commercial and industrial electricity prices, while 2018 and 2019 saw flattening of this growth. Industrial

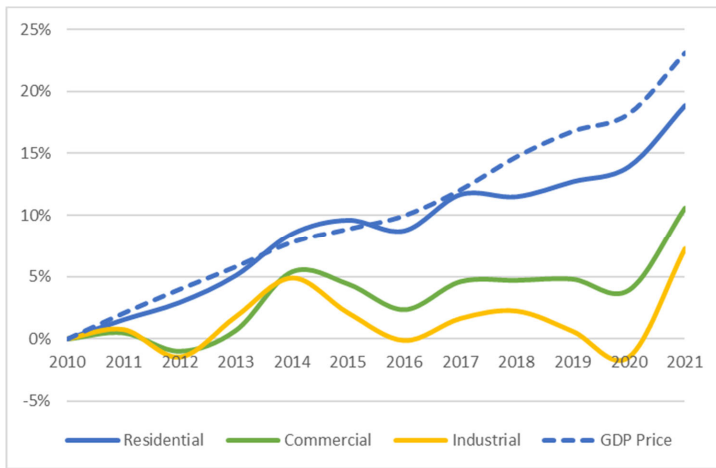
<sup>46</sup> EIA State Electricity Profiles with Data for 2021 (<http://www.eia.gov/electricity/state/>)

<sup>47</sup> All prices in this section are estimated as real 2019 prices adjusted using the GDP implicit price deflator unless otherwise indicated.



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electricity prices declined in 2019 and 2020 due to the effects of the pandemic. Prices rose in 2021 as a result of higher input fuel prices and increasing demand. The increase in nominal electricity prices for the major end use categories, as well as increases in the GDP price index for comparison, are shown in Figure 2-7.



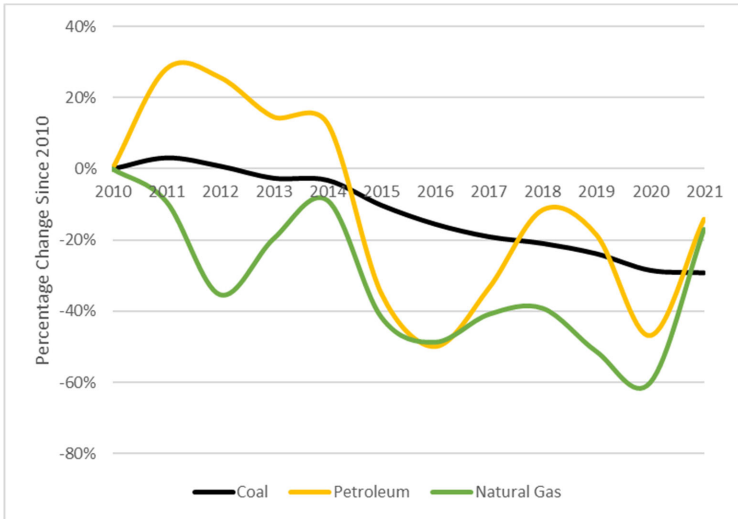
**Figure 2-7. Relative Increases in Nominal National Average Electricity Prices for Major End-Use Categories (including taxes), With Inflation Indices**  
 Source: EIA. Electric Power Annual 2021, Table 2.4.

### 2.3.2 Prices of Fossil Fuels Used for Generating Electricity

Another important factor in the changes in electricity prices are the changes in delivered fuel prices<sup>48</sup> for the three major fossil fuels used in electricity generation: coal, natural gas and petroleum products. Relative to real prices in 2014, the national average real price (in 2019\$) of coal delivered to EGUs in 2020 had decreased by 26 percent, while the real price of natural gas decreased by 56 percent. The real price of delivered petroleum products also decreased by 55 percent, and petroleum products declined as an EGU fuel (in 2020 petroleum products generated 1 percent of electricity). The combined real delivered price of all fossil fuels (weighted by heat input) in 2020 decreased by 39 percent over 2014 prices. Figure 2-8 shows the relative changes in real price of all 3 fossil fuels between 2010 and 2021.

<sup>48</sup> Fuel prices in this section are all presented in terms of price per MMBtu to make the prices comparable.

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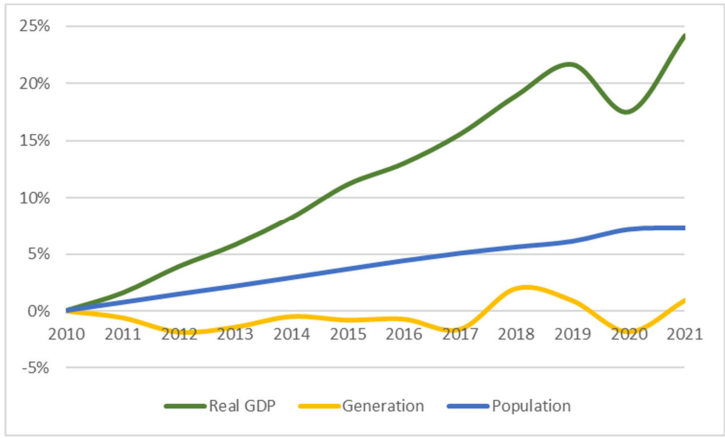
**Figure 2-8. Relative Real Prices of Fossil Fuels for Electricity Generation; Change in National Average Real Price per MMBtu Delivered to EGU**

Source: EIA. Electric Power Annual 2020 and 2021, Table 7.1.

### 2.3.3 Changes in Electricity Intensity of the U.S. Economy from 2015 to 2021

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2010 and 2021 is that while total net generation increased by 1 percent over that period, the demand growth for generation was lower than both the population growth (7 percent) and real GDP growth (24 percent). Figure 2-9 shows the growth of electricity generation, population and real GDP during this period.

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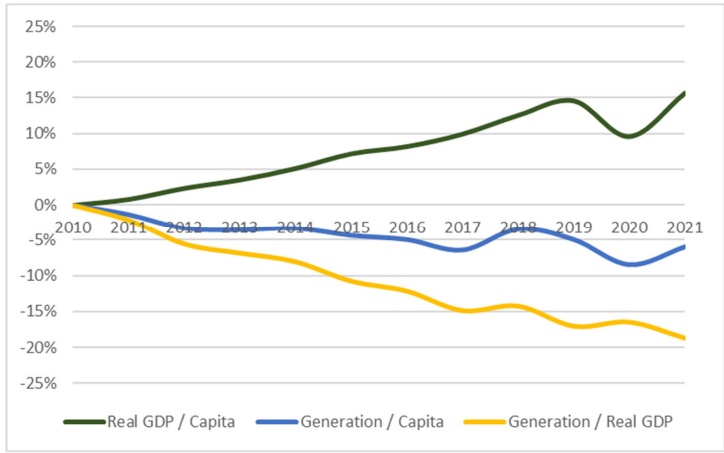


**Figure 2-9. Relative Growth of Electricity Generation, Population and Real GDP Since 2014**

Sources: Generation: U.S. EIA Electric Power Annual 2021 and 2020. Population: U.S. Census. Real GDP: 2022 Economic Report of the President, Table B-3.

Because demand for electricity generation grew more slowly than both the population and GDP, the relative electric intensity of the U.S. economy improved (i.e., less electricity used per person and per real dollar of output) during 2010 to 2021. On a per capita basis, real GDP per capita grew by 16 percent between 2010 and 2021. At the same time electricity generation per capita decreased by 6 percent. The combined effect of these two changes improved the overall electricity generation efficiency in the U.S. market economy. Electricity generation per dollar of real GDP decreased 19 percent. These relative changes are shown in Figure 2-10.

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**Figure 2-10. Relative Change of Real GDP, Population and Electricity Generation Intensity Since 2014**

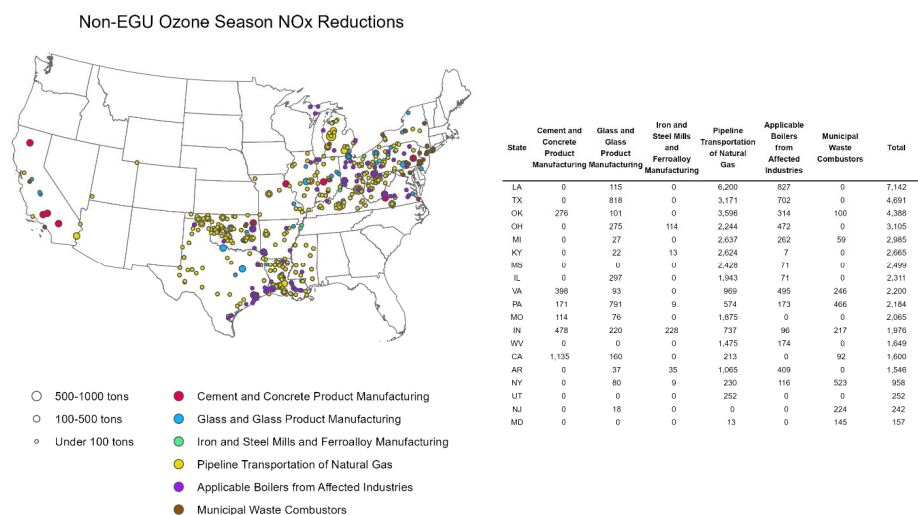
Sources: Generation: U.S. EIA Electric Power Annual 2021 and 2020. Population: U.S. Census. Real GDP: 2022 Economic Report of the President, Table B-3.

**2.4 Industrial Sectors Overview**

The final rule establishes various ozone season NO<sub>x</sub> emission limits beginning in 2026, including emissions limits for reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; for kilns in Cement and Cement Product Manufacturing; for reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; for furnaces in Glass and Glass Product Manufacturing; 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 combustors or incinerators in Solid Waste Combustors and Incinerators.<sup>49</sup> Figure 2-11 shows the locations<sup>50</sup> of the estimated non-EGU emissions reductions by industry. For additional discussion of the emissions limits, see Section I.B. of the preamble. The following sections provide overviews of these industries. For additional information on these non-EGU industries please see the Final Non-EGU Sectors TSD in the docket.

<sup>49</sup> Boilers with design capacity of 100 mmBtu/hr or greater.

<sup>50</sup> Facility location information is based on the 2019 inventory, which is discussed in Chapter 4, Section 4.5.4.



**Figure 2-11. Geographical Distribution of Non-EGU Ozone Season NOx Reductions and Summary of Reductions by Industry and by State**

#### 2.4.1 Cement and Cement Product Manufacturing

Hydraulic cement (primarily portland cement) is a key component of an important construction material: concrete. Concrete is used in a wide variety of applications (e.g., residential and commercial buildings, public works projects), and cement demand is influenced by national and regional trends in these sectors.

Portland cement is a fine powder, gray or white in color, that consists of a mixture of hydraulic cement materials comprising primarily calcium silicates, aluminates and aluminoferrites. More than 30 raw materials are known to be used in the manufacture of portland cement, and these materials can be divided into four distinct categories: calcareous, siliceous, argillaceous, and ferriferous (containing iron). These materials are chemically combined through pyroprocessing (heat) and subjected to subsequent mechanical processing operations to form gray and white portland cement. Gray portland cement is used for structural applications and is the more common type of cement produced. White portland cement has lower iron and manganese contents than gray portland cement and is used primarily for decorative purposes.

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There are two processes for manufacturing cement: the wet process and the dry process. In the wet process, water is added to the raw materials during the blending process and before feeding the mixture into the rotary kiln. In contrast, the dry process feeds the blended material directly into the rotary kiln in a dry state. Newer dry process plants also use preheater and precalciner technologies that partially heat and calcine the blended raw materials before they enter the rotary kiln. These technologies can increase the overall energy efficiency of the cement plant and reduce production costs. The fuel efficiency differences between the wet and dry processes have led to a substantial decline in clinker capacity provided by the wet process over the last 3 decades. (Van Oss and Padovani, 2002). The number of wet process plants fell from 32 in 2000 to 7 in 2017 (DOI, USGS, 2020).

Cement kilns are used by the cement industry in the production of cement. Portland cement, used in almost all construction applications, is the industry's primary product. Essentially all of the NO<sub>x</sub> emissions associated with cement manufacturing are generated in the kilns because of high process temperatures. To manufacture cement, raw materials such as limestone, cement rock, sand, iron ore, clay and shale are crushed, blended, and fed into a kiln. These materials are then heated in the kiln to temperatures above 2900°F to induce a chemical reaction (called "fusion") that produces cement "clinker," a round, marble-sized, glass-hard material. The clinker is then cooled, mixed with gypsum and ground to produce cement. Clinker is also defined as the product of a portland cement kiln from which finished cement is manufactured by milling and grinding.

Nearly all cement clinker is produced in large rotary kiln systems. The rotary kiln is a refractory brick lined cylindrical steel shell equipped with an electrical drive to rotate it at 1-3 revolutions per minute, through which hot combustion gases flow counter-currently to the feed materials. The kiln can be fired with coal, oil, natural gas, waste (e.g., solvents) or a combination of these fuels. There are various types of kilns in use, including long wet kilns, long dry kilns, kilns with a preheater and kilns with a precalciner. The long wet and dry kilns and most preheater kilns have only one fuel combustion zone, whereas the newer precalciner kilns and preheater kilns with a riser duct have two fuel combustion zones.

In a wet kiln, the ground raw materials are suspended in water to form a slurry and introduced into the inlet feed. This kiln type employs no preheating of the dry feed. In a long dry

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kiln, the raw materials are dried to a powder and introduced into the inlet feed in a dry form, but this kiln type employs no preheating of the dry feed. Currently more cement plants use the dry process because of its lower energy requirement. In a precalciner kiln, the feed to the kiln system is preheated in cyclone chambers; the kiln uses a second burner to calcine material in a separate vessel attached to the preheater before the final fusion in a kiln that forms clinker.

Because the typical operating temperatures of these kilns differ, the NO<sub>x</sub> formation mechanisms also differ among these kiln types. In a primary combustion zone at the hot end of a kiln, the high temperatures lead to predominantly thermal NO<sub>x</sub> formation. In the secondary combustion zone, however, lower gas-phase temperatures suppress thermal NO<sub>x</sub> formation. The temperatures at which these kilns operate influence what NO<sub>x</sub> control technologies can be applied. For instance, SNCR can operate effectively at typical cement kiln temperatures (above 1500°F), while SCR typically operates effectively at lower temperatures (550-800°F). Energy efficiency is also important in reducing NO<sub>x</sub> emissions; for example, a high thermal efficiency equates to less heat and fuel being consumed and, therefore, less NO<sub>x</sub> is produced.

Portland cement is produced using a combination of variable inputs such as raw materials, labor, electricity, and fuel. U.S. Census data for the cement industry (North American Industry Classification System [NAICS] 32731: cement manufacturing) provides an initial overview of aggregated industry expenditures on these inputs (Department of Commerce [DOC], Bureau of the Census, 2021). In 2019, the total value of shipments was \$9 billion, and the industry spent approximately \$1.5 billion on materials, parts, and packaging, or 16.6% of the value of shipments. Total compensation for all employees (includes payroll and fringe benefits) amounted to \$1.4 billion (15.6%) and included 15,590 employees.

A review and description of market characteristics (i.e., degree of concentration, entry barriers, and product differentiation) can enhance our understanding of how U.S. cement markets operate. These characteristics provide indicators of a firm's ability to influence market prices by varying the quantity of cement it sells. For example, in markets with large numbers of sellers and identical products, firms are unlikely to be able to influence market prices via their production decisions (i.e., they are "price takers"). However, in markets with few firms, significant barriers to entry (e.g., licenses, legal restrictions, or high fixed costs), or products that are similar but can

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be differentiated, the firm may have some degree of market power (i.e., set or significantly influence market prices).

Cement sales are often concentrated locally among a small number of firms for two reasons: high transportation costs and production economies of scale. Transportation costs significantly influence where cement is ultimately sold; high transportation costs relative to unit value provide incentives to produce and sell cement locally in regional markets (USITC, 2006). To support this claim, the empirical literature has typically pointed to Census of Transportation data showing over 80% of cement shipments were made within a 200-mile radius (Jans and Rosenbaum, 1997) and reported evidence of high transportation costs per dollar of product value from case studies (Ryan, 2006). The cement industry is also very capital intensive, and entry requires substantial investments. In addition, large plants are typically more economical because they can produce cement at lower unit costs; this reduces entry incentives for small sized cement plants and firms. EPA has recognized these aspects of the cement industry and its market structure in its economic impact analyses of rules on this industry in previous reports, such as the RIA prepared in 2010 for the portland cement NESHAP and NSPS (EPA, 2010).

#### *2.4.2 Iron and Steel Mills and Ferroalloy Manufacturing*

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. Pig iron is the primary output of iron making and the primary input to the next step in the process, steel making. Metal scrap and flux are also used in steel making. The steel making process produces molten steel that is shaped into solid forms at forming mills. Finishing mills then shape, harden, and treat the semi-finished steel to yield its final marketable condition.

Steel often undergoes additional, referred to as secondary, metallurgical processes after it is removed from the steel making furnace. Secondary steel making takes place in vessels, smaller furnaces, or the ladle. These sites do not have to be as strong as the primary refining furnaces because they are not required to contain the powerful primary processes. Secondary steel making can have many purposes, such as removal of oxygen, sulfur, hydrogen, and other gases by exposing the steel to a low-pressure environment; removal of carbon monoxide through the use



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of deoxidizers such as aluminum, titanium, and silicon; and changing of the composition of unremovable substances such as oxides to further improve mechanical properties.

In 2019, the United States produced 87.8 million metric tons of steel (USGS, 2019). Steel is primarily used as a major input to consumer products such as automobiles and appliances. Therefore, the demand for steel is a derived demand that depends on a diverse base of consumer products. In addition, the Infrastructure Investment and Jobs Act, signed into law in 2021, will likely increase demand in both the iron and steel industry as well as the concrete and cement industry. The historic investment in roads, bridges, airports, and other physical infrastructure around the country will require large inputs from these industries.

U.S. Census data for the iron and steel industry (North American Industry Classification System [NAICS] 331110: Iron and steel mills and ferroalloy manufacturing) provides an initial overview of aggregated industry expenditures on these inputs (Census Bureau, 2021). In 2019, the total value of shipments was \$93.7 billion, and the industry spent approximately \$56.4 billion on materials, parts, and packaging, or 60% of the value of shipments. Total compensation for all employees (includes payroll and fringe benefits) amounted to \$10.1 billion (10.8%) and included 85,707 employees.

#### *2.4.3 Glass and Glass Product Manufacturing*

Commercially produced glass can be classified as soda-lime, lead, fused silica, borosilicate, or 96 percent silica. Soda-lime glass consists of sand, limestone, soda ash, and cullet (broken glass). The manufacturing of such glass occurs in four phases: (1) preparation of raw material, (2) melting in the furnace, (3) forming and (4) finishing. The products of the glass manufacturing industry are flat glass, container glass, and pressed and blown glass. The procedures for manufacturing glass are the same for all products except forming and finishing. Container glass and pressed and blown glass use pressing, blowing, or pressing and blowing to form the desired product. Flat glass, which is the remainder, is formed by float, drawing, or rolling processes.

As the sand, limestone, and soda ash raw materials are received, they are crushed and stored in separate elevated bins. These materials are then transferred through a gravity feed system to a weigher and mixer, where the material is mixed with cullet to ensure homogeneous

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melting. The mixture is conveyed to a batch storage bin where it is held until dropped into the feeder to the glass melting furnace. All equipment used in handling and preparing the raw material is housed separately from the furnace and is usually referred to as a batch plant.

The glass melting furnaces contribute to most of the total emissions from the glass plant. Essentially all the NO<sub>x</sub> emissions associated with glass manufacturing are generated in the melting furnaces due to the high process temperatures. These materials are then heated in the furnace to temperatures around 3000°F to induce fusion that produces molten glass. After molten glass is produced, it then goes to be shaped by pressing, blowing, pressing and blowing, drawing, rolling, or floating to produce the desired product. The end products undergo finishing (decorating or coating) and annealing (removing unwanted stress area in the glass) as required. During the inspection process, any damaged or undesirable glass is transferred back to the batch plant to be used as cullet.

Glass manufacturing furnaces can vary between the various categories of glass produced (container, flat, or pressed/blown). This is because the different types of glass vary in composition and quality specifications. Therefore, each type of glass produced requires different energy inputs to fuse the raw materials. As a result, the emissions from similar furnaces producing different types of glass can vary significantly. Furnaces can also be fired with gaseous or liquid fuels.

U.S. Census data for the glass manufacturing industry (North American Industry Classification System [NAICS] 32721) provides an initial overview of aggregated industry expenditures on these inputs (Census Bureau, 2021). In 2019, the total value of shipments was \$27.6 billion, and the industry spent approximately \$10.9 billion on materials, parts, and packaging, or 40% of the value of shipments. Total compensation for all employees (includes payroll and fringe benefits) amounted to \$5.3 billion and included 91,988 employees.

#### *2.4.4 Pipeline Transportation of Natural Gas*

This industry comprises establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems. This industry includes the storage of natural gas because the storage is usually done by the pipeline establishment and because a pipeline is inherently a network in which all the nodes are interdependent.

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U.S. Census data for the pipeline transportation of natural gas industry (North American Industry Classification System [NAICS] 486210) provides an initial overview of aggregated industry expenditures on these inputs (Census Bureau, 2021). In 2019, the total value of shipments was \$27.6 billion, annual payroll totaled \$3.3 billion, and the industry included 27,294 employees.

#### *2.4.5 Industrial Boilers*

This rulemaking includes NO<sub>x</sub> emission limits on boilers from an additional five industries. One of those industries is Iron and Steel Mills and Ferroalloy Manufacturing, which was discussed above; the remaining four industries are discussed briefly below.

This first industry is Metal Ore Mining. Taconite, the principal iron ore mined in the United States, has a low (20 percent to 30 percent) iron (Fe) content and is found in hard, fine-grained, banded iron formations. The main taconite iron ore deposits are located near Lake Superior in Minnesota (Mesabi Iron Range) and Michigan (Marquette Iron Range). The taconite mining operations in Michigan and Minnesota accounted for virtually all domestic iron ore production (Kirk, 1999).

The next industry is the pulp, paper, and paperboard mills industry. Manufacturing of paper and paper products is a complex process that is carried out in two distinct phases: the pulping of wood and the manufacture of paper. Pulping is the conversion of fibrous wood into a “pulp” material suitable for use in paper, paperboard, and building materials. Pulping and papermaking may be integrated at the same production facility, or facilities may produce either pulp or paper alone. In addition to facilities that produce pulp and/or paper, there are numerous establishments that do not manufacture paper, but convert paper into secondary products.

Steam boilers are pivotal in the paper industry for the process of drying the paper, energy requirement, and the cooking of wood chips in the digester. The steam is used for cooking wood chips, dryer cans, and to produce power for the plant. Power can be produced through the combustion of bark, black liquor, and fuel oil to reduce the cost with large electric demand and increase reliability versus outside power sources. Firms engaged in pulp and paper manufacturing under the North American Industry Classification System (NAICS) code 3221. In 2019, the pulp and paper industry shipped products valued at over \$76 billion and included

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92,283 employees (U.S. Census Bureau, 2021). This industry has declined in the United States with a 22% decrease in the number of establishments and a 42% decrease in the number of employees from 2000 to 2019.

The next industry is the petroleum and coal products manufacturing industry. The impacted boilers in this industry come from petroleum refineries. Petroleum pumped directly out of the ground, or crude oil, is a complex mixture of hydrocarbons (chemical compounds that consist solely of hydrogen and carbon) and various impurities, such as salt. To manufacture the variety of petroleum products recognized in everyday life, this complex mixture must be refined and processed over several stages. Boilers are used for several functions in a petroleum refining facility. The steam generated from the boiler can be used to power turbines and pumps or for heating of facilities and processes. Large refineries use lots of steam to heat crude oil during the distillation process.

The process of refining crude oil into useful petroleum products can be separated into two phases and a number of supporting operations. In the first phase, crude oil is desalted and then separated into its various hydrocarbon components (known as “fractions”). These fractions include gasoline, kerosene, naphtha, and other products. In the second phase, the distilled fractions are converted into petroleum products (such as gasoline and kerosene) using three different types of downstream processes: combining, breaking, and reshaping (EPA, 1995).

The petroleum refining industry is comprised of establishments primarily engaged in refining crude petroleum into finished petroleum products. Examples of these products include gasoline, jet fuel, kerosene, asphalt, lubricants, and solvents. Firms engaged in petroleum refining are categorized under the North American Industry Classification System (NAICS) code 324110. In 2019, the petroleum refining industry shipped products valued at over \$547 billion and included 63,659 employees (U.S. Census Bureau, 2021).

The fourth industry is basic chemical manufacturing, which includes establishments primarily engaged in manufacturing chemicals using basic processes, such as thermal cracking and distillation. Chemicals manufactured in this industry group are usually separate chemical elements or separate chemically-defined compounds.

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The chemicals industry is one of the most complex and diverse industries in the U.S., and simple characterizations are impossible. While the EIA Manufacturing Energy Consumption Survey (MECS) identifies 10 significant steam-consuming product categories within the chemical industry, it identifies only nine for the food, paper, refining and primary metals industries, combined. The major steam consuming processes in the chemical industry include stripping, fractionalization, power generation, mechanical drive, quenching and dilution.

U.S. Census data for the basic chemical manufacturing industry (North American Industry Classification System [NAICS] 3251) provides an initial overview of aggregated industry expenditures. In 2019, the value of shipments for the industry was \$206 billion and included 143,000 employees (U.S. Census Bureau, 2021).

#### *2.4.6 Municipal Waste Combustors*

Municipal solid waste (MSW) combustion is the process of reducing the volume of MSW through incineration (combustion). Because combustion reduces waste volume by as much as 90 percent, this method of waste management has the potential to significantly reduce the need for landfills. Combustion has two principal functions—MSW volume reduction and energy generation—and produces residual products of ash and emissions to the ambient air. The inputs are capital services (e.g., combustor unit, land, building, air pollution control devices), operating services (e.g., labor services, maintenance services, fuel for startup, utility services), and MSW.

Municipal waste combustors (MWCs) can be classified according to three principal types: mass burn (MB), modular (MOD), and refuse-derived fuel (RDF) combustors. Variations exist within these categories, and some designs incorporate features of more than one type. Regardless of the technology, each MWC plant site or facility has at least one, and potentially more than one, individual combustor unit. Typically, an MWC plant has two or three units on site.

The U.S. Economic Census (U.S. Bureau of the Census) classifies affected MWCs in a category called solid waste combustors and incinerators (NAICS 562213). Between 2012 and 2017 the industry declined from 109 establishments and \$2.5 billion in sales to 61 establishments and \$1.3 billion in sales (U.S. Census Bureau, 2021). In 2020 the industry consisted of 60

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establishments, an annual payroll of \$191 million, and 1,803 employees (U.S. Census Bureau, 2021).

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## CHAPTER 3: AIR QUALITY IMPACTS

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### Overview

This chapter presents the impacts on ozone concentrations in 2023 and ozone and PM<sub>2.5</sub> in 2026 from emissions reductions associated with the three regulatory control alternatives (i.e., final rule, less stringent alternative, and more stringent alternative) analyzed in this RIA.<sup>51</sup> Specifically, for 2023 we analyzed the impacts of ozone season (i.e., May through September) NO<sub>x</sub> emissions reductions from EGUs on April through September average Maximum Daily Average 8-hour ozone concentrations (AS-MO3) for each of the three control alternatives. For 2026<sup>52</sup> we analyzed the impacts on AS-MO3 from ozone season NO<sub>x</sub> emissions reductions from EGUs and from non-EGU separately and combined for each of the three alternatives. In addition, for 2026 we also analyzed the impacts on annual average PM<sub>2.5</sub> concentrations from the changes in EGU emissions of NO<sub>x</sub>, SO<sub>2</sub>, and directly emitted PM<sub>2.5</sub> outside of the ozone season that are expected to result from certain EGU NO<sub>x</sub> controls that are expected to operate year-round and generation shifting in response to the implementation of EGU controls in the three regulatory control alternatives (see Chapter 4).<sup>53</sup>

In this chapter we first describe the methods for developing spatial fields of air quality concentrations<sup>54</sup> for the baseline and regulatory control alternatives in 2023 and 2026. These spatial fields provide the air quality data that are used in the environment justice (EJ) analysis and the analysis of health benefits from reduced concentrations of ozone and PM<sub>2.5</sub> that are expected to result from this final rule. In brief, the spatial fields are constructed based on a method that utilizes 2026 baseline ozone and PM<sub>2.5</sub> contributions from emissions in individual states, state-level emissions for the baseline and each of the regulatory control alternatives, along

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<sup>51</sup> The 2023 and 2026 baseline and regulatory controls alternatives are described in Chapter 4.

<sup>52</sup> The baseline EGU emissions and emissions reductions from the three EGU regulatory control alternatives that were used to create spatial fields for 2026 align with the 2025 EGU baseline and control alternatives emissions described in Chapter 4.

<sup>53</sup> The approach for creating spatial fields of annual average PM<sub>2.5</sub> concentrations is not capable of handling emissions reductions that vary by season. In this regard, our impact analysis for annual average PM<sub>2.5</sub> does not include NO<sub>x</sub> emissions reductions during the ozone season. Excluding ozone season NO<sub>x</sub> reductions is not expected to bias the annual impacts because NO<sub>x</sub> emissions primarily affect concentrations of PM nitrate, which is a secondary pollutant that is formed during the cooler months of the year with near zero concentrations measured during the summer. Similarly, we do not include the impacts of non-EGU NO<sub>x</sub> reductions on annual average PM<sub>2.5</sub> because the non-EGU emissions limits are only required to operate during the ozone season.

<sup>54</sup> Spatial fields are comprised of gridded pollutant concentration and contribution data at 12 km resolution covering the portion of the U.S. within the air quality modeling domain.



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with baseline spatial fields of ozone and PM<sub>2.5</sub> concentrations. The basic methodology for determining air quality changes for this final rule are the same as those used in the proposal RIA and in RIAs for multiple previous rules (U.S. EPA, 2019; U.S. EPA, 2020a; U.S. EPA, 2020b; U.S. EPA, 2021).

In Section 3.1 we describe the air quality modeling platform; in Section 3.2 we describe the method for processing air quality modeling outputs to create spatial fields; in Section 3.3 we describe how this method was applied for the analyses in this RIA; in Section 3.4 we present maps showing the impacts on AS-MO3 and annual PM<sub>2.5</sub> for each of the regulatory control alternatives compared to the corresponding baseline; and in Section 3.5 we identify uncertainties and limitations in the application of the method for generating spatial fields of pollutant concentrations.

In Appendix 3A, we provide the estimated impacts on projected 2026 ozone design values that are expected to result from the emissions reductions from the combined EGU and non-EGU final rule case. The impacts on design values are based on air quality modeling of the 2026 final rule baseline and the 2026 final rule.

### **3.1 Air Quality Modeling Platform**

The EPA used photochemical air quality modeling as part of the process to create spatial fields that reflect the influence of emissions changes between the baseline and each of the regulatory control alternatives in each year, as applicable, for this final rule RIA. The model simulations (i.e., model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx) version 7.10<sup>55</sup> (Ramboll Environ, 2021). The nationwide modeling domain (i.e., the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12×12 km, as shown in Figure 3-1. Model predictions were evaluated by comparing predictions of base year 2016 ozone and PM<sub>2.5</sub> concentrations to ambient measurements (U.S. EPA, 2022a; 2022b). Ozone and PM<sub>2.5</sub> model evaluations showed model performance that was comparable to other contemporaneous

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<sup>55</sup> This CAMx simulation set the Rscale NH<sub>3</sub> dry deposition parameter to 0, which resulted in more realistic model predictions of PM<sub>2.5</sub> nitrate concentrations than using a default Rscale parameter of 1.

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model applications and, therefore, deemed adequate for the purpose of creating spatial fields for the purposes of this RIA.



**Figure 3-1 Air Quality Modeling Domain**

As noted above, the process for creating spatial fields utilized ozone and PM<sub>2.5</sub> concentrations as well as the contributions from EGU and non-EGU emissions in individual states. The contributions to assess the impacts on AS-MO3 for the final rule are the same as those used for the proposed rule. That is, for this final rule analysis we used the 2026 ozone concentrations and corresponding EGU and non-EGU contribution predictions from the 2016 version 2 (i.e., 2016v2) emissions platform that was developed and used for proposal.<sup>56</sup> In the proposal RIA, we relied on benefit per ton estimates to compute the benefits expected from reductions in annual average PM<sub>2.5</sub> concentrations. For this final rule we conducted PM<sub>2.5</sub> state-by-state source apportionment air quality modeling to quantify contributions to annual PM<sub>2.5</sub> from EGU emissions of NO<sub>x</sub>, SO<sub>2</sub>, and directly emitted PM<sub>2.5</sub> in 2026. The data from this modeling were used to develop spatial fields of annual average PM<sub>2.5</sub> for the 2026 baseline and each of the three EGU regulatory control alternatives in that year. In order to provide consistency between the analyses for ozone and the analyses for PM<sub>2.5</sub>, the source apportionment modeling

<sup>56</sup> The 2016v2 emissions platform includes emissions data for 2016, 2023, 2026, and 2032. For the final rule, the EPA developed a version 3 (v3) emissions inventory, which reflects updates based largely on comments on the proposal. As described in the text, for this final rule RIA, we use the v2 modeling in a relative sense coupled with the v3 emissions to create spatial fields for the final rule 2023 and 2026 baseline scenarios and the regulatory control alternatives.

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for PM<sub>2.5</sub> was performed using the same inputs and model configuration as we used for the ozone source apportionment modeling performed for the proposed rule analysis.

The contributions to ozone and PM<sub>2.5</sub> component species (e.g., sulfate, nitrate, ammonium, elemental carbon (EC), organic aerosol (OA), and crustal material<sup>57</sup>) were modeled using the source apportionment tools in CAMx. Ozone contributions were modeled using the Anthropogenic Precursor Culpability Assessment (APCA) tool and PM<sub>2.5</sub> contributions were modeled using the Particulate Matter Source Apportionment Technology (PSAT) tool (Ramboll, 2021). In general, source apportionment modeling quantifies the air quality concentrations formed from individual, user-defined groups of emissions sources or “tags.”<sup>58</sup> These source tags are tracked through the transport, dispersion, chemical transformation, and deposition processes within the model to obtain hourly gridded<sup>59</sup> contributions from the emissions in each individual tag to hourly gridded modeled concentrations. For this RIA we used the source apportionment contribution data to provide a means to estimate the effect of changes in emissions from each group of emissions sources (i.e., each tag) to changes in ozone and PM<sub>2.5</sub> concentrations. Specifically, we applied outputs from the 2026 baseline state-by-state EGU and non-EGU source apportionment modeling to obtain the contributions from EGU and non-EGU emissions in each state to concentrations and the contributions in each 12 x 12 km model grid cell nationwide. The ozone source apportionment modeling was performed for the period April through September to provide data for developing spatial fields for the April through September AS-MO3 ozone exposure metric. The PM<sub>2.5</sub> source apportionment modeling was performed for a full year to provide data for developing spatial fields of annual average PM<sub>2.5</sub>.

### **3.2 Applying Modeling Outputs to Create Spatial Fields**

In this section we describe the method for creating spatial fields of AS-MO3 and annual average PM<sub>2.5</sub> based on the air quality modeling for 2016v2 and 2026v2. The foundational data include (1) ozone and speciated PM<sub>2.5</sub> concentrations in each model grid cell from the 2016 and 2026 v2 modeling, (2) ozone contributions in 2026v2 from EGU and non-EGU ozone season

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<sup>57</sup> Crustal material refers to elements that are commonly found in the earth’s crust such as Aluminum, Calcium, Iron, Magnesium, Manganese, Potassium, Silicon, Titanium and the associated oxygen atoms.

<sup>58</sup> Each state was treated as a separate source tag. Note that point source (EGU and non-EGU) sources on tribal lands were assigned to a national “tribal land” tag.

<sup>59</sup> Hourly contribution information is provided for each grid cell to provide spatial patterns of the contributions from each tag.

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emissions in each state and speciated PM<sub>2.5</sub> contributions in 2026v2 from annual EGU emissions in each state in each model grid cell, (3) 2026v2 emissions from EGUs and non-EGUs that were inputs to the contribution modeling, and (4) the EGU and non-EGU v3 emissions from the final rule 2023 and 2026 baseline scenarios and each of the three regulatory control alternatives in 2023 and 2026.

The method to create spatial fields applies scaling factors to gridded source apportionment contributions based on emissions changes between the 2026v2 baseline and the 2023v3 and 2026v3 baseline and regulatory control alternatives. This method is described in detail below.

Spatial fields of ozone and PM<sub>2.5</sub> in 2026 were created based on “fusing” modeled data with measured concentrations at air quality monitoring locations. To create the spatial fields for each future emissions scenario these fused model fields are used in combination with 2026 state-EGU and non-EGU source apportionment modeling and the EGU and non-EGU emissions for each regulatory control alternative and analytic year, as applicable. Contributions from each contribution “tag” were scaled based on the ratio of emissions in the year/alternative being evaluated to the emissions in the modeled 2026 scenario. Contributions from tags representing sources other than EGUs and non-EGUs are held constant at 2026 levels for each of the alternatives and year. For each alternative and year analyzed, the scaled contributions from all sources were summed together to create a gridded surface of total modeled ozone and PM<sub>2.5</sub>. The process is described in a step-by-step manner below. For ozone, the process for creating spatial fields of AS-MO3 concentrations is explained using an EGU control case as an illustrative example. This process was performed to create AS-MO3 spatial fields for the 2023 and 2026 baselines and for the EGU and non-EGU regulatory control alternatives analyzed for this final rule RIA. For annual PM<sub>2.5</sub>, we describe the steps for creating spatial fields for the 2026 baseline and EGU regulatory control alternatives.

### ***3.2.1 Spatial Distribution of Ozone Impacts***

When interpreting the spatial fields of AS-MO3 it is important to recognize that ozone is a secondary pollutant, meaning that it is formed through chemical reactions of precursor emissions in the atmosphere. As a result of the time necessary for precursors to mix in the atmosphere and for these reactions to occur, ozone can either be highest at the location of the

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precursor emissions or peak at some distance downwind of those emissions sources. The spatial gradients of ozone depend on a multitude of factors including the spatial patterns of NO<sub>x</sub> and VOC emissions and the meteorological conditions on a particular day. Thus, on any individual day, high ozone concentrations may be found in narrow plumes downwind of specific point sources, may appear as urban outflow with large concentrations downwind of urban source locations or may have a more regional signal. However, in general, because the AS-MO<sub>3</sub> metric is based on the average of concentrations over more than 180 days in the spring and summer, the resulting spatial fields are rather smooth without sharp gradients, compared to what might be expected when looking at the spatial patterns of maximum daily 8-hour average (MDA8) ozone concentrations on specific high ozone episode days.

The impacts of the regulatory control alternatives for EGUs in 2023 and 2026 on ozone season EGU NO<sub>x</sub> emissions for all states are provided in Table 3-1.<sup>60</sup> The impacts of the regulatory control alternatives for non-EGUs in 2026 on ozone season non-EGU NO<sub>x</sub> emissions by state are provided in Table 3-2. Note that negative values in Tables 3-1 and 3-2 denote a reduction in emissions and positive values denote an increase in emissions.<sup>61</sup> The spatial fields of baseline AS-MO<sub>3</sub> in 2023 and 2026 are presented in Figure 3-2 and Figure , respectively. The distribution of AS-MO<sub>3</sub> baseline concentrations in 2023 and 2026 are similar, but the concentrations are somewhat lower in 2026, as is expected due to emissions reductions resulting from continued implementation of existing “on-the-books” rules and regulations. The figures show that, from a regional perspective, the highest AS-MO<sub>3</sub> concentrations are in the intermountain and southwest portions of the western U.S. where contributions from background sources are dominant outside of urban areas, and in southern and central California where there are high emissions of ozone precursor pollutants. Within the eastern U.S. the highest concentrations are seen in the Ohio Valley and portions of the Midwest, as well as along the Northeast Corridor and near urban areas such as Atlanta and Houston.

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<sup>60</sup> Emission reductions at sources on tribal lands are included in the tribal lands categories all of the emissions tables in this chapter.

<sup>61</sup> The imposition of the final rule results in changes in regional electricity flows, resulting in changes in net imports. As a result, some states (even those not subject to the rule) may see changes in emissions as a result of generation shifting.

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**Table 3-1. Impact on EGU Ozone Season NO<sub>x</sub> Emissions of each Regulatory Control Alternative in 2023 and in 2026 (1,000 tons)**

State	2023 EGU Ozone Season NO <sub>x</sub> Emissions			2026 EGU Ozone Season NO <sub>x</sub> Emissions		
	Final – Baseline	Less Stringent – Baseline	More Stringent – Baseline	Final – Baseline	Less Stringent – Baseline	More Stringent – Baseline
Alabama	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Arizona	0.0	0.0	0.0	-0.3	0.0	0.5
Arkansas	-0.3	-0.3	-0.3	-5.7	-0.4	-7.0
California	0.1	0.1	0.1	0.0	0.0	0.0
Colorado	0.0	0.0	0.0	0.1	0.0	0.0
Connecticut	0.0	0.0	0.0	0.0	0.0	0.0
Delaware	0.0	0.0	0.0	0.0	0.0	0.0
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0
Georgia	0.0	0.0	0.1	0.0	0.0	0.6
Idaho	0.0	0.0	0.0	0.1	0.0	0.0
Illinois	-0.1	-0.1	-0.1	0.3	0.0	0.9
Indiana	-0.1	-0.1	-0.1	-1.1	0.1	-2.0
Iowa	0.0	0.0	0.0	0.3	-0.1	-0.1
Kansas	0.0	0.0	0.0	0.4	0.0	1.0
Kentucky	-0.8	-0.8	-1.1	-2.3	-0.6	-6.0
Louisiana	-0.3	-0.3	-0.3	-4.0	-1.7	-4.0
Maine	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	0.0	0.0	0.0	0.0	0.0
Massachusetts	0.0	0.0	0.0	0.0	0.0	0.0
Michigan	0.0	0.0	0.0	-2.1	0.1	-3.4
Minnesota	-1.0	-1.0	-1.0	-1.2	-1.2	-1.2
Mississippi	-1.0	-1.0	-1.0	-0.1	-0.2	0.0
Missouri	-1.8	-1.8	-1.8	-4.8	-1.8	-6.3
Montana	0.0	0.0	0.0	0.0	0.0	0.0
Nebraska	0.0	0.0	0.0	0.1	0.0	0.0
Nevada	-0.5	-0.5	-0.5	0.0	0.0	0.0
New Hampshire	0.0	0.0	0.0	0.0	0.0	0.0
New Jersey	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
New Mexico	0.0	0.0	0.0	0.0	0.0	0.0
New York	-0.2	-0.2	-0.2	-0.2	-0.2	-0.1

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State	2023 EGU Ozone Season NO <sub>x</sub> Emissions			2026 EGU Ozone Season NO <sub>x</sub> Emissions		
	Final – Baseline	Less Stringent – Baseline	More Stringent – Baseline	Final – Baseline	Less Stringent – Baseline	More Stringent – Baseline
North Carolina	0.0	0.0	-0.1	0.4	0.0	0.3
North Dakota	0.0	0.0	0.0	0.1	0.1	0.1
Ohio	-0.2	-0.2	-0.2	-1.5	-1.5	-1.5
Oklahoma	-1.4	-1.4	-1.4	-2.2	-1.3	-4.4
Oregon	0.0	0.0	0.0	0.0	0.0	0.0
Pennsylvania	0.0	-0.1	0.0	0.1	-0.1	0.0
Rhode Island	0.0	0.0	0.0	0.0	0.0	0.0
South Carolina	0.0	0.0	0.0	0.2	0.1	0.0
South Dakota	0.0	0.0	0.0	0.0	0.0	0.0
Tennessee	0.0	0.0	0.0	0.0	-0.1	0.6
Texas	-1.2	-1.2	-1.2	-1.1	-1.3	-14.3
Utah	-1.5	-1.5	-1.5	-4.8	-0.1	-5.9
Vermont	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	0.0	0.0	0.0	0.2	0.0	-0.2
Washington	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	1.2	1.2	1.3	-1.7	1.0	-2.9
Wisconsin	-0.4	-0.4	-0.4	0.1	0.0	0.0
Wyoming	0.0	0.0	0.0	0.5	-0.5	0.8
Tribal Lands	0.0	0.0	0.0	-1.3	0.0	-1.3
Nationwide	-9.9	-9.8	-10.0	-31.8	-9.9	-56.0

**Table 3-2. Impact on Non-EGU Ozone Season NO<sub>x</sub> Emissions of each Regulatory Control Alternative in 2026 (1,000 tons)**

State	2026 Non-EGU Ozone Season NO <sub>x</sub> Emissions		
	Policy – Baseline	Less Stringent – Baseline	More Stringent – Baseline
Alabama	0.0	0.0	0.0
Arizona	0.0	0.0	0.0
Arkansas	-1.6	-0.5	-1.7
California	-1.6	-1.5	-4.5
Colorado	0.0	0.0	0.0

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State	2026 Non-EGU Ozone Season NO <sub>x</sub> Emissions		
	Policy – Baseline	Less Stringent – Baseline	More Stringent – Baseline
Connecticut	0.0	0.0	0.0
Delaware	0.0	0.0	0.0
District of Columbia	0.0	0.0	0.0
Florida	0.0	0.0	0.0
Georgia	0.0	0.0	0.0
Idaho	0.0	0.0	0.0
Illinois	-2.4	-0.8	-3.1
Indiana	-2.0	-1.4	-3.5
Iowa	0.0	0.0	0.0
Kansas	0.0	0.0	0.0
Kentucky	-3.0	-0.7	-3.5
Louisiana	-8.5	-2.2	-9.2
Maine	0.0	0.0	0.0
Maryland	-0.1	-0.1	-1.1
Massachusetts	0.0	0.0	0.0
Michigan	-3.2	-0.8	-5.4
Minnesota	0.0	0.0	0.0
Mississippi	-2.9	-0.6	-3.1
Missouri	-2.1	-0.6	-4.8
Montana	0.0	0.0	0.0
Nebraska	0.0	0.0	0.0
Nevada	0.0	0.0	0.0
New Hampshire	0.0	0.0	0.0
New Jersey	-0.2	-0.2	-0.3
New Mexico	0.0	0.0	0.0
New York	-1.0	-0.7	-1.5
North Carolina	0.0	0.0	0.0
North Dakota	0.0	0.0	0.0
Ohio	-3.4	-1.1	-4.3
Oklahoma	-7.7	-2.4	-9.3
Oregon	0.0	0.0	0.0
Pennsylvania	-2.3	-1.7	-4.7
Rhode Island	0.0	0.0	0.0
South Carolina	0.0	0.0	0.0
South Dakota	0.0	0.0	0.0
Tennessee	0.0	0.0	0.0



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State	2026 Non-EGU Ozone Season NO <sub>x</sub> Emissions		
	Policy – Baseline	Less Stringent – Baseline	More Stringent – Baseline
Texas	-6.6	-2.7	-14.1
Utah	-0.4	-0.1	-1.0
Vermont	0.0	0.0	0.0
Virginia	-1.8	-0.8	-2.2
Washington	0.0	0.0	0.0
West Virginia	-2.0	-0.5	-2.5
Wisconsin	0.0	0.0	0.0
Wyoming	0.0	0.0	0.0
Tribal Lands	0.0	0.0	0.0
Nationwide	-52.9	-19.4	-79.7

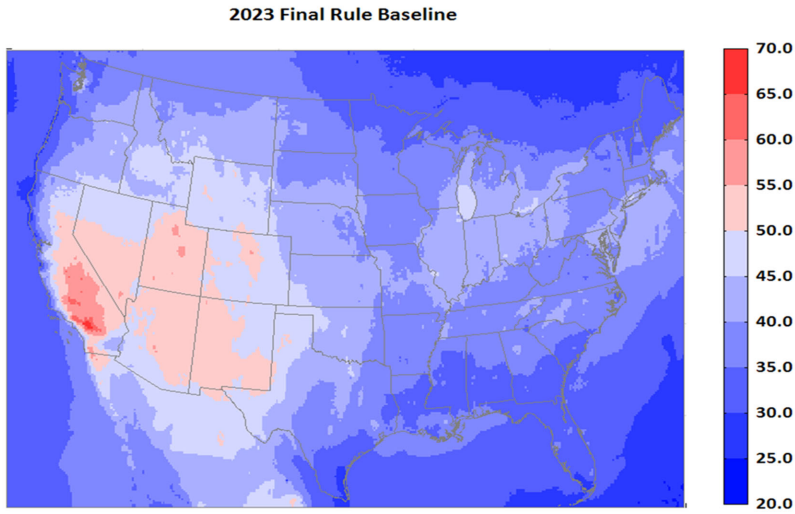
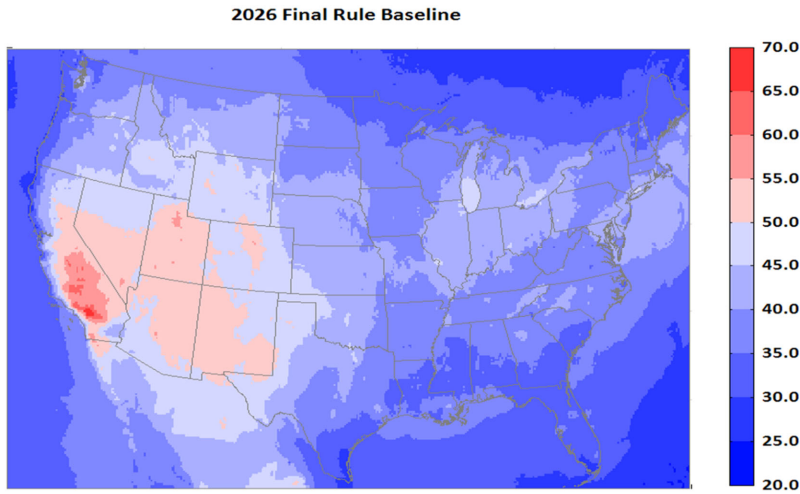


Figure 3-2. 2023 Baseline AS-MO3 Concentrations (ppb)

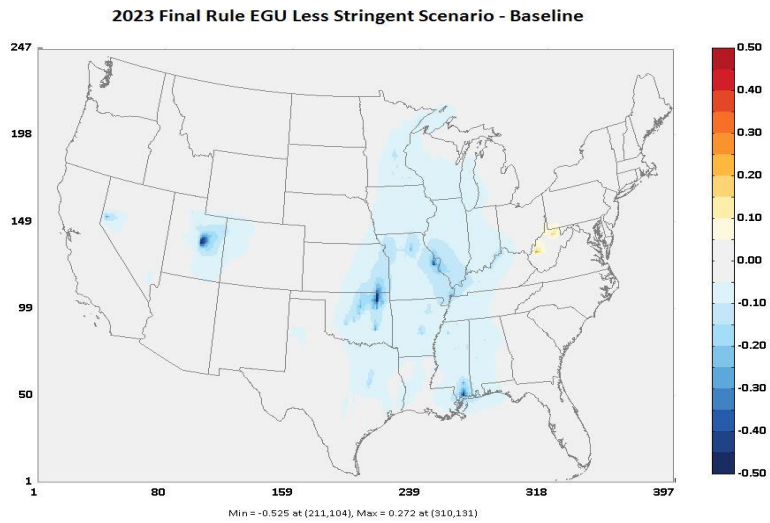


**Figure 3-3. 2026 Baseline AS-MO3 Concentration (ppb)**

The estimated impacts on AS-MO3 between the baseline and each of the regulatory control alternatives for 2023 and 2026 are presented in Figure 3-4 through Figure 3-15. The ppb differences shown in Figures 3-4 through 3-15 are calculated as the regulatory control alternative minus the baseline (i.e., negative values indicate reductions in pollutant concentrations). Note that the scale for the impacts of the more stringent alternative in 2026, as shown in Figure 3-15, is larger than the scale used to display the impacts for the less stringent alternative and final rule alternatives in Figures 3-13 and 3-14, respectively.

The spatial patterns of the impacts of emissions reductions are a result of (1) the location of EGU and non-EGU sources with reduced ozone season NO<sub>x</sub> emissions between the baseline and the corresponding regulatory control alternatives and (2) the physical or chemical processing that the model simulates in the atmosphere. In this respect, ozone reductions are greatest in proximity to the affected sources with regional impacts in areas further downwind from these sources. Increases in ozone concentrations in parts of West Virginia seen in the 2023 regulatory control alternatives reflect the increase in ozone season EGU NO<sub>x</sub> emissions in this state, as indicated in Table 3-1.

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**Figure 3-4. Reduction in AS-MO3 (ppb): 2023 Less Stringent EGU-only Alternative vs the 2023 Baseline (scale:  $\pm 0.5$  ppb)**

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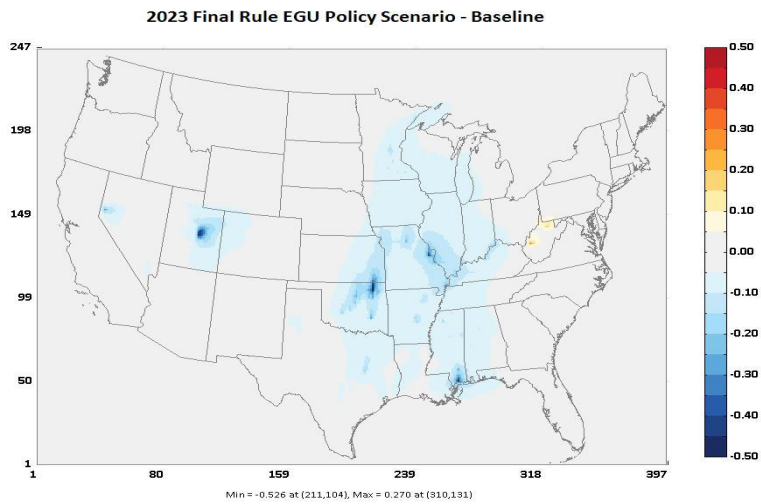


Figure 3-5. Reduction in AS-MO3 (ppb): 2023 Final Rule EGU-only Alternative vs the 2023 Baseline (scale:  $\pm 0.5$  ppb)

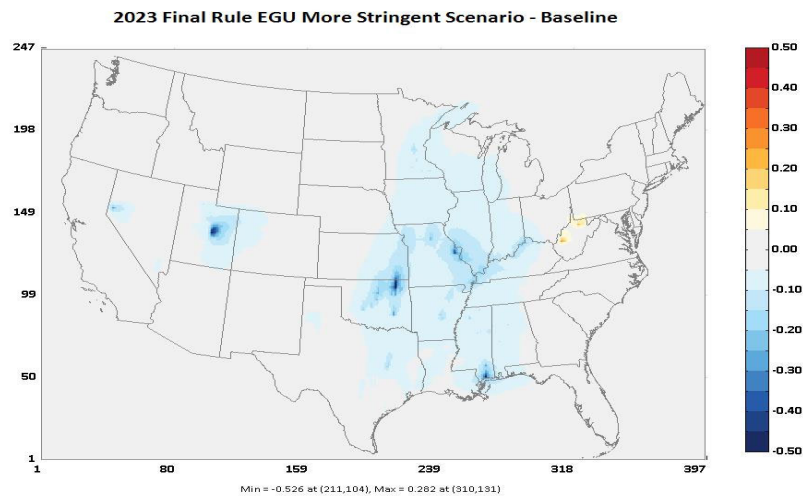


Figure 3-6. Reduction in AS-MO3 (ppb): 2023 More Stringent EGU-only Alternative vs the 2023 Baseline (scale:  $\pm 0.5$  ppb)

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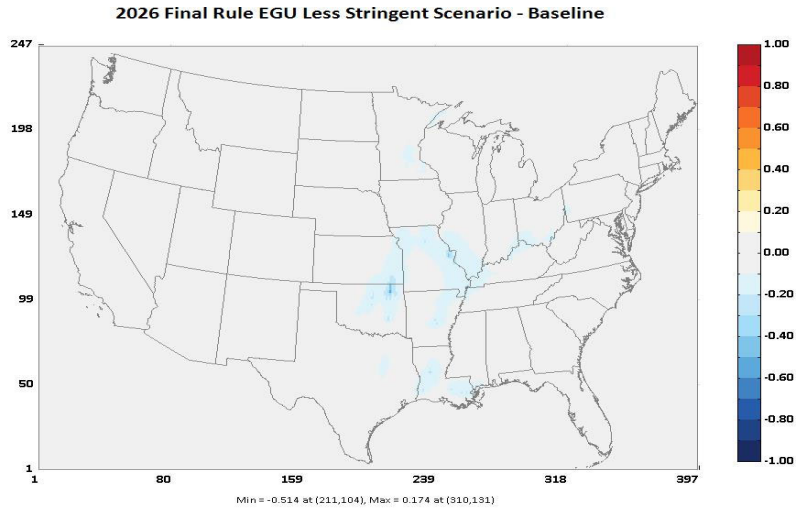


Figure 3-7. Reduction in AS-MO3 (ppb): 2026 Less Stringent EGU-only Alternative vs the 2026 Baseline (scale:  $\pm 1.0$  ppb)

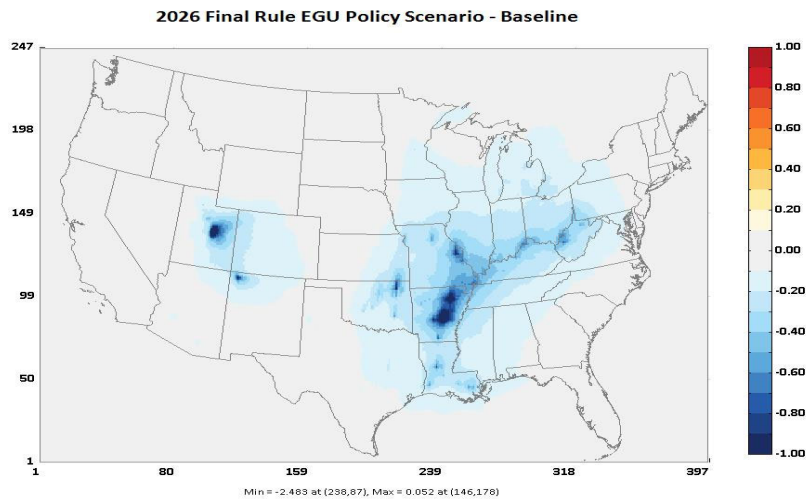
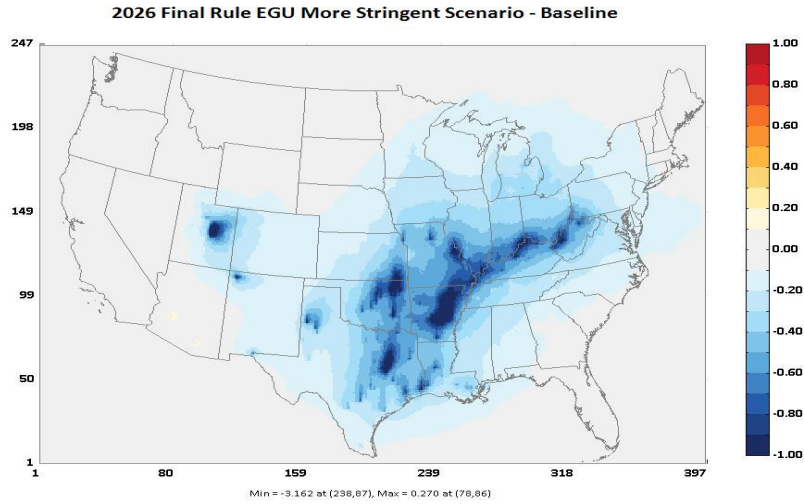
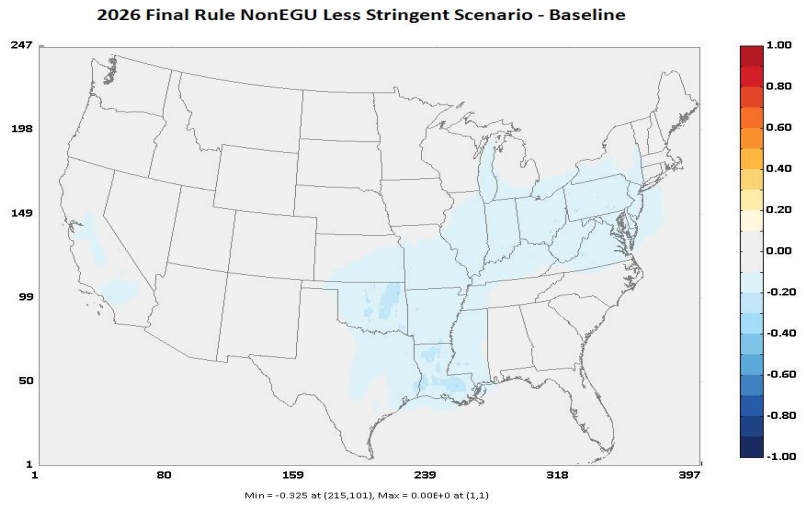


Figure 3-8. Reduction in AS-MO3 (ppb): 2026 Final Rule EGU-only Alternative vs the 2026 Baseline (scale:  $\pm 1.0$  ppb)

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**Figure 3-9. Reduction in AS-MO3 (ppb): 2026 More Stringent EGU-only Alternative vs the 2026 Baseline (scale:  $\pm 1.0$  ppb)**



**Figure 3-10. Reduction in AS-MO3 (ppb): 2026 Less Stringent non-EGU-only Alternative vs the 2026 Baseline (scale:  $\pm 1.0$  ppb)**

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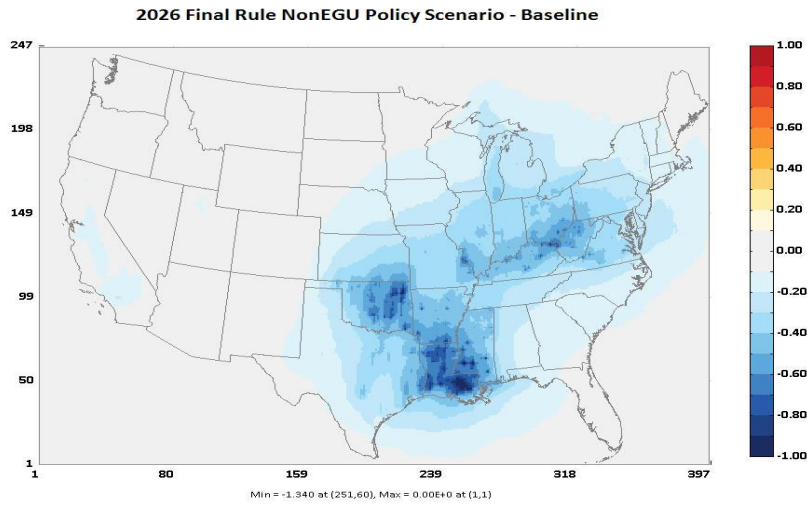


Figure 3-11. Reduction in AS-MO3 (ppb): 2026 Final Rule non-EGU-only Alternative vs the 2026 Baseline (scale:  $\pm 1.0$  ppb)

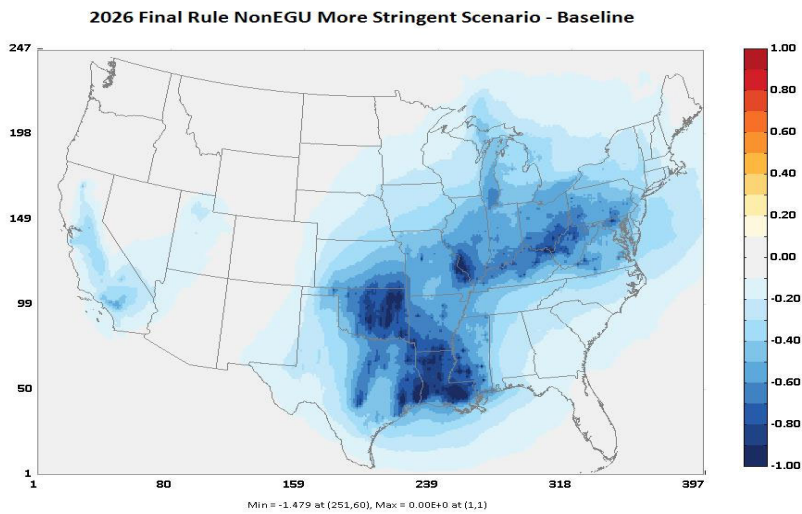


Figure 3-12. Reduction in AS-MO3 (ppb): 2026 More Stringent non-EGU-only Alternative vs the 2026 Baseline (scale:  $\pm 1.0$  ppb)

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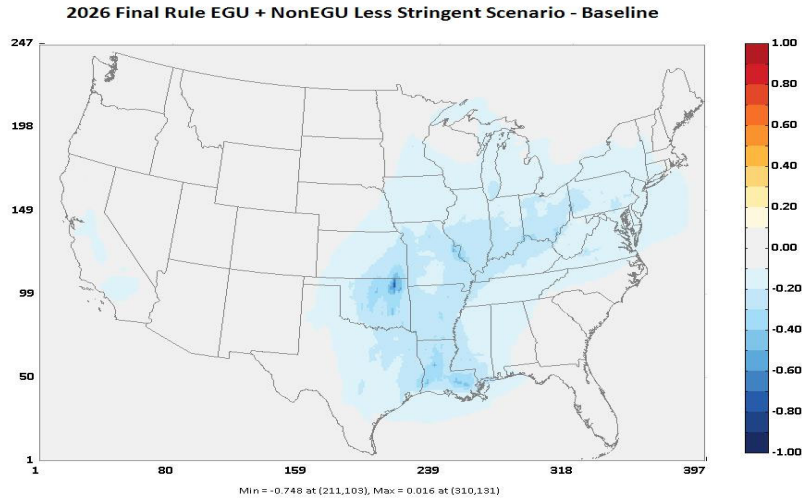


Figure 3-13. Reduction in AS-MO3 (ppb): 2026 Less Stringent EGU+non-EGU Alternative vs the 2026 Baseline (scale:  $\pm 1.0$  ppb)

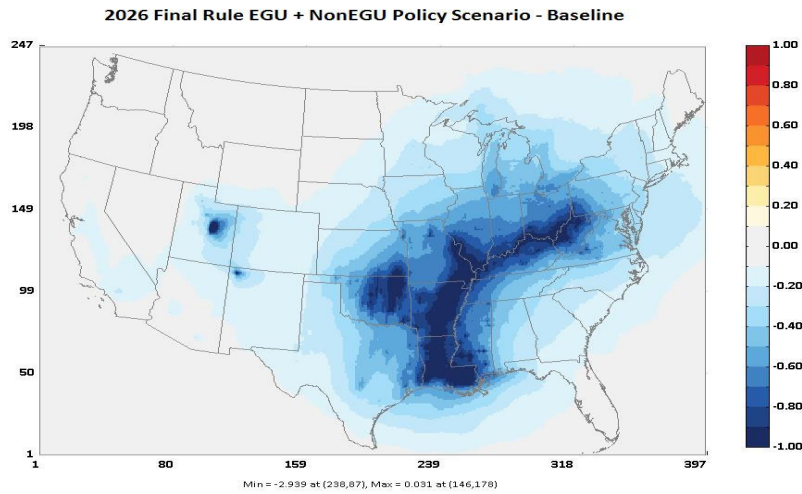
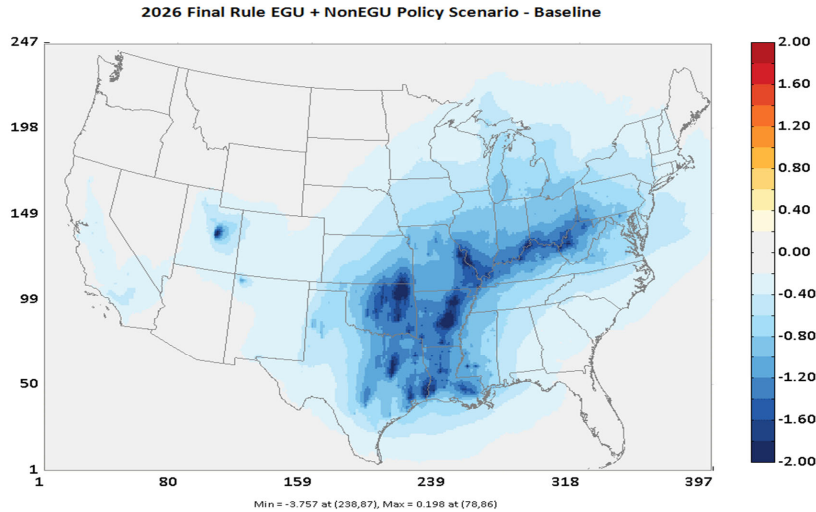


Figure 3-14. Reduction in AS-MO3 (ppb): 2026 Final Rule EGU+non-EGU Alternative vs the 2026 Baseline (scale:  $\pm 1.0$  ppb)





**Figure 3-15. Reduction in AS-MO3 (ppb): 2026 More Stringent EGU+non-EGU Alternative vs the 2026 Baseline (scale:  $\pm 2.0$  ppb)**

### 3.2.2 Spatial Distribution of PM<sub>2.5</sub> Impacts

In contrast to ozone, PM<sub>2.5</sub> is comprised of both primary and secondary components. Secondary PM<sub>2.5</sub> species sulfate and nitrate often exhibit relatively smooth regional patterns without large local gradients while primary PM<sub>2.5</sub> components often have heterogeneous spatial patterns with largest gradients near emissions sources. The spatial field of 2026 baseline annual PM<sub>2.5</sub> is provided in Figure 3-16. Both secondary and primary PM<sub>2.5</sub> contribute to the spatial pattern of 2026 baseline annual PM<sub>2.5</sub> as illustrated by the extensive areas of elevated concentrations over much of the East that are comprised of secondary PM<sub>2.5</sub> component species. In addition, relatively high concentrations are mainly evident in urban areas and in close proximity to major point sources. These “hot spots” generally reflect the impact of primary PM emissions. Locally high concentrations are also evident in parts of the Northwest as a result of wood stove emissions during the cooler months of the year (Hadley, 2021). High PM<sub>2.5</sub> concentrations are also evident in California’s Central Valley mainly comprised of particulate nitrate and sulfate (Hasheminassab, 2014).

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The impacts of the regulatory control alternatives for EGUs in 2026 on annual EGU NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>2.5</sub> emissions by state are provided in Table 3-3. Note that negative values in Table 3-3 denote a reduction in emissions and positive values denote an increase in emissions. In Figures 3-17 through 3-19 we present the changes in annual average PM<sub>2.5</sub> concentrations between the 2026 baseline and the three EGU regulatory control alternatives. The spatial patterns of changes in annual average PM<sub>2.5</sub> are a result of (1) of the spatial distribution of EGU sources that are predicted to have changes in emissions in the control alternatives compared to the baseline and (2) of the physical or chemical processing that the model simulates in the atmosphere. The emissions data in Table 3-3 show that the reductions in SO<sub>2</sub> emissions expected to result from the final rule and more stringent alternative are much larger than emissions reductions of NO<sub>x</sub> or PM<sub>2.5</sub>. Geographically, the SO<sub>2</sub> emissions reductions are most notable in Arkansas and Louisiana. In addition, there are relatively large reductions in SO<sub>2</sub> emissions in Kentucky, Michigan, and Texas. The spatial pattern of reductions in annual average PM<sub>2.5</sub> concentrations, as shown in Figures 3-17 through 3-19, are consistent with the location of SO<sub>2</sub> emissions reductions. The largest reductions in PM<sub>2.5</sub> are found in and downwind of the states with the largest reductions in emissions.

**Table 3-3. Impact on EGU Annual NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>2.5</sub> Emissions of each Regulatory Control Alternative for EGUs in 2026 (1,000 tons)<sup>a</sup>**

State	Final Rule – Baseline			Less Stringent – Baseline			More Stringent – Baseline		
	NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>2.5</sub>
Alabama	-0.2	-0.2	0.0	-0.1	-0.1	0.0	-1.1	-1.3	-0.1
Arizona	-0.5	-0.8	0.0	0.1	0.1	0.0	0.8	1.4	0.0
Arkansas	-0.6	-15.8	-0.3	-0.6	-0.1	0.0	-6.8	-19.7	-0.2
California	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	-0.1
Colorado	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	0.0
Connecticut	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Georgia	0.0	0.1	0.0	-0.1	0.0	0.0	1.4	1.4	0.1
Idaho	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Illinois	0.1	0.1	0.1	0.0	0.0	0.0	1.1	2.4	0.1
Indiana	-0.8	-1.9	-0.1	-1.1	-2.8	-0.2	1.0	1.3	0.2

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State	Final Rule – Baseline			Less Stringent – Baseline			More Stringent – Baseline		
	NOx	SO2	PM2.5	NOx	SO2	PM2.5	NOx	SO2	PM2.5
Iowa	-0.1	0.1	0.0	-0.1	-0.1	0.0	0.1	0.0	0.0
Kansas	-0.1	0.1	0.0	0.0	0.0	0.0	1.6	0.6	0.3
Kentucky	0.0	5.7	0.0	-0.3	8.5	0.0	-11.5	-22.7	-0.3
Louisiana	-2.7	-15.3	-0.4	-2.6	-9.5	-0.3	-3.0	-15.7	-0.4
Maine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Massachusetts	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Michigan	0.0	-3.0	-0.2	0.1	0.0	0.0	-8.1	-19.4	-0.8
Minnesota	-1.9	-0.3	0.0	-1.9	-0.2	0.0	-1.7	-0.2	0.0
Mississippi	-0.1	-0.1	0.0	0.0	-0.1	0.0	0.2	0.3	0.1
Missouri	0.1	-2.6	-0.2	0.1	0.0	0.0	-7.2	-1.7	-0.4
Montana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nebraska	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nevada	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
New Hampshire	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Jersey	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
New Mexico	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.0	0.0	0.0	-0.1	0.0	0.0	0.1	0.0	0.0
North Carolina	0.0	0.3	0.0	0.0	0.0	0.0	0.3	-1.4	0.0
North Dakota	0.6	0.9	0.0	0.4	0.6	0.0	1.0	1.3	0.1
Ohio	-2.1	-2.5	-0.3	-2.1	-2.2	-0.2	-2.1	-2.3	-0.2
Oklahoma	-2.1	2.0	0.0	-2.3	3.4	0.0	-4.8	2.3	0.0
Oregon	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pennsylvania	0.4	0.2	0.2	-0.1	-0.2	0.0	1.5	1.5	0.5
Rhode Island	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Carolina	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	-0.2	0.0
South Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tennessee	-0.1	0.0	0.0	-0.1	-0.1	0.0	2.2	2.9	0.6
Texas	0.1	-1.2	0.0	-0.1	-2.0	0.0	-17.3	-45.2	-0.6
Utah	0.0	-3.0	-0.1	0.0	-0.7	0.0	-12.9	0.8	0.0
Vermont	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.0	-0.1
Washington	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0
West Virginia	3.0	-1.8	-0.2	3.0	0.0	0.0	-7.4	-5.9	-0.8
Wisconsin	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Wyoming	0.9	1.6	0.0	-1.1	-1.3	0.0	1.6	2.6	0.0

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State	Final Rule – Baseline			Less Stringent – Baseline			More Stringent – Baseline		
	NOx	SO2	PM2.5	NOx	SO2	PM2.5	NOx	SO2	PM2.5
Tribal Data	0.0	-0.4	-0.2	0.0	0.0	0.0	-3.0	-0.9	-0.5
Nationwide	-6.2	-37.7	-1.5	-8.9	-6.8	-0.7	-73.0	-118.1	-2.3

<sup>a</sup> The imposition of the final rule results in changes in regional electricity flows, resulting in changes in net imports. As a result, some states (even those not subject to the rule) may see changes in emissions as a result of generation shifting.

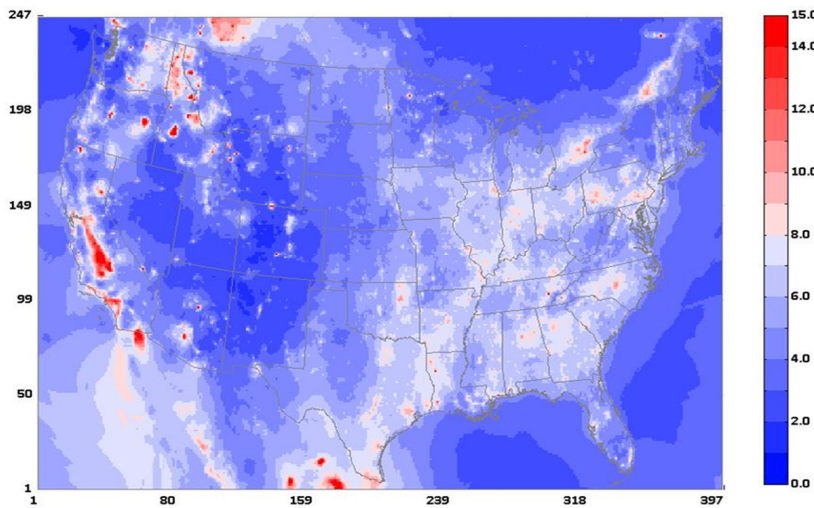


Figure 3-16. 2026 Baseline Annual Average PM<sub>2.5</sub> Concentrations (µg/m<sup>3</sup>)

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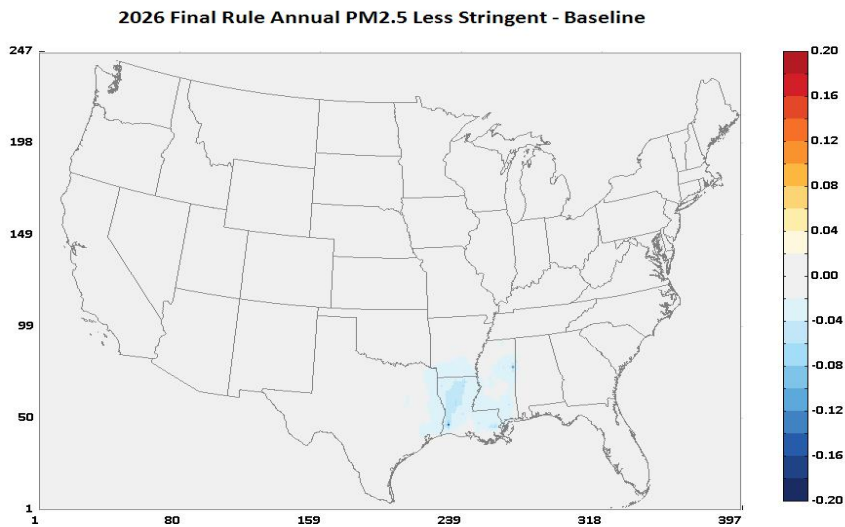


Figure 3-17. Reduction in annual average PM<sub>2.5</sub> (µg/m<sup>3</sup>): 2026 Less Stringent EGU-only Alternative vs the 2026 Baseline (scale: ± 0.2 µg/m<sup>3</sup>)

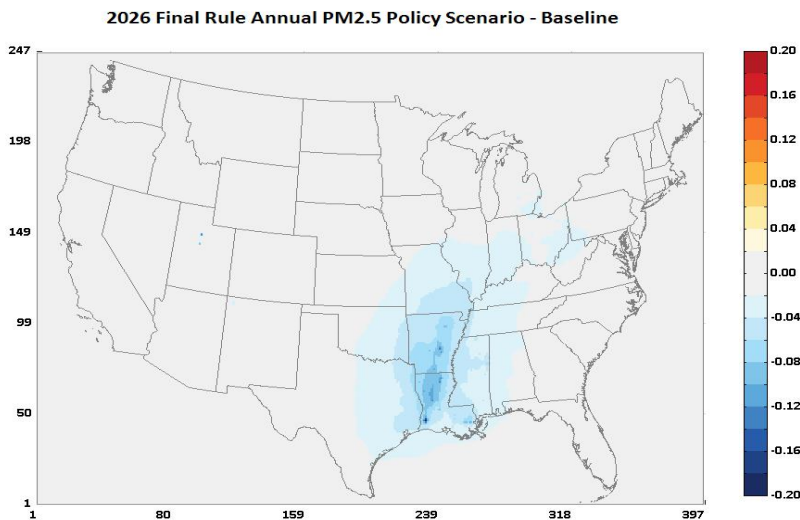


Figure 3-18. Reduction in Annual Average PM<sub>2.5</sub> (µg/m<sup>3</sup>): 2026 Final Rule EGU-only Alternative vs the 2026 Baseline (scale: ± 0.2 µg/m<sup>3</sup>)

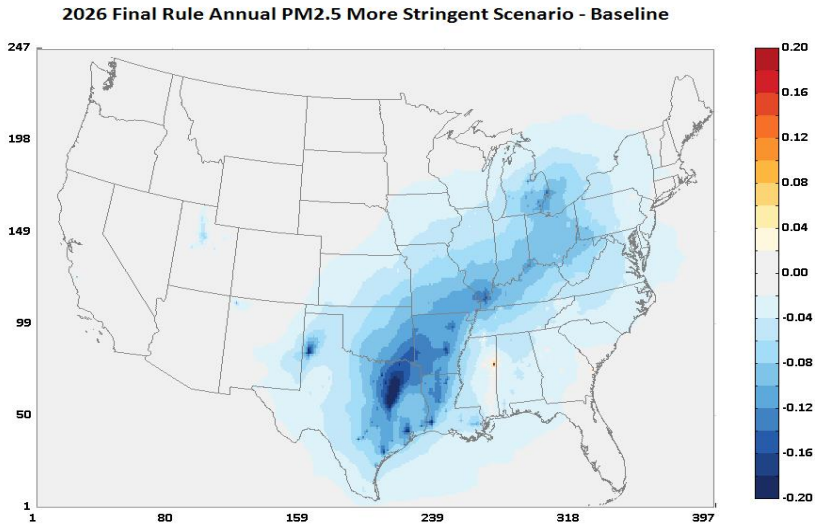


Figure 3-19. Reduction in Annual Average PM<sub>2.5</sub> (µg/m<sup>3</sup>): 2026 More Stringent EGU-only Alternative vs the 2026 Baseline (scale: ± 0.2 µg/m<sup>3</sup>)

### 3.3 Uncertainties and Limitations

One limitation of the scaling methodology for creating ozone and PM<sub>2.5</sub> surfaces associated with the baseline and regulatory control alternatives described above is that it treats air quality changes from the tagged sources as linear and additive. It therefore does not account for nonlinear atmospheric chemistry and does not account for interactions between emissions of different pollutants and between emissions from different tagged sources. This is consistent with how air quality estimations have been treated in past regulatory analyses (U.S. EPA 2012; 2019; 2020b). We note that air quality is calculated in the same manner for the baseline and the regulatory control alternatives, so any uncertainty associated with these assumptions is carried through both sets of scenarios in the same manner and is thus not expected to impact the air quality differences between scenarios. In addition, emissions changes between baseline and the regulatory control alternatives are relatively small compared to modeled 2026 emissions that form the basis of the source apportionment approach described in Section 3.1. Previous studies have shown that air pollutant concentrations generally respond linearly to small emissions changes of up to 30 percent (Dunker et al., 2002; Cohan et al., 2005; Napelenok et al., 2006; Koo

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et al., 2007; Zavala et al., 2009; Cohan and Napelenok, 2011) and that linear scaling from source apportionment can do a reasonable job of representing impacts of 100 percent of emissions from individual sources (Baker and Kelly 2014). Therefore, while simplistic, it is reasonable to expect that the emissions concentration differences between the baseline and regulatory control alternatives can be adequately represented using this methodology and any uncertainty should be weighed against the speed in which this method may be used to account for spatial differences in the effect of EGU emissions on ozone concentrations.

A second limitation is that the source apportionment contributions represent the spatial and temporal distribution of the emissions from each source tag as they occur in the 2026 modeled case. Thus, the contribution modeling results do not allow us to represent any changes to “within tag” spatial distributions. As a result, the method does not account for any changes of spatial patterns that would result from changes in the relative magnitude of sources within a source tag in the scenarios investigated here.

In addition, the 2023 and 2026 CAMx-modeled concentrations themselves have some uncertainty. While all models have some level of inherent uncertainty in their formulation and inputs, the base-year 2016 model outputs have been evaluated against ambient measurements and have been shown to adequately reproduce spatially and temporally varying ozone concentrations (U.S. EPA, 2022a; U.S. EPA, 2022b).

The regulatory control alternatives lead to decreased concentrations of ozone, the extent to which varies by location, relative to the baseline. However, the analysis does not account for how interaction with NAAQS compliance would affect the benefits and costs of the regulatory control alternatives, which introduces uncertainty in the benefits and costs of the alternatives. To the extent the Transport FIP for the 2015 ozone NAAQS will decrease NO<sub>x</sub> and consequentially ozone concentrations, these changes may affect compliance with existing NAAQS standards and subsequently affect the actual benefits and costs of the rule. In areas not projected to attain the 2015 ozone NAAQS without further emissions reductions from the baseline, states may be able to avoid applying some emissions control measures to reduce emissions from local sources as a result of this rule. If compliance behavior with the 2015 ozone NAAQS were accounted for in the baseline in this RIA there may be additional social benefits from reduced compliance costs,

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while the level and spatial pattern of changes in ozone concentrations, and their associated health and ecological benefits, would differ. The directional effect on the benefits, costs, and net-benefits of this source of uncertainty is ambiguous.

Similarly, the regulatory control alternatives may project decreases in ozone concentrations in areas attaining the NAAQS in the baseline. In practice, these potential changes in concentrations may influence NAAQS compliance plans in these areas, which in turn would further influence concentrations and the cost of complying with the NAAQS. However, such behavior will be mitigated by NAAQS requirements such as Prevention of Significant Deterioration (PSD) requirements. This RIA does not account for how interaction with NAAQS compliance would affect the benefits and costs of the regulatory control alternatives.

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## **APPENDIX 3A: IMPACTS ON OZONE DESIGN VALUES OF THE FINAL RULE IN 2026**

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In this appendix we provide the estimated impacts on projected 2026 ozone design values that are expected to result from the combined EGU and non-EGU final rule analyzed in this RIA. As described in Chapter 1, the regulatory control alternatives include the final rule along with alternatives that reflect less stringent and more stringent controls on EGUs and non-EGUs. Because of timing constraints, we were only able to perform full-scale photochemical air quality modeling to quantify the ozone impacts for the 2026 final rule.

### **3A.1 Projected Impacts on Ozone Design Values**

The “ppb” impacts in 2026 from the final rule control case are provided in Table 3A-1 for those monitoring sites that are identified as nonattainment or maintenance-only receptors in 2026 and/or in 2023, based on air quality modeling and monitored data. Table 3A-2 provides the same information for the additional violating monitor-based maintenance-only receptors in 2023.<sup>62</sup>

For the final rule control case, the largest reductions in ozone design values at the receptors in Tables 3A-1 and 3A-2 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. Lesser 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. The geographical variations of the impacts on design values are generally consistent with the spatial fields in Figure 3-14, which shows the impact on AS-MO3 of the final rule case EGU+non-EGU NO<sub>x</sub> reductions in 2026. Table 3A-3 provides the impacts on EGU+non-EGU ozone season NO<sub>x</sub>

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<sup>62</sup> The approaches for identifying modeling-based and violating monitor-based receptors are described in the preamble for this final rule.

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emissions that result from the emissions controls modeled in the final rule case. Note that negative values in Table 3A-3 denote a reduction in emissions whereas positive values denote an increase in emissions. The impacts on emissions are rank ordered by the amount of emissions reduction (i.e., negative values are at the top). That is, in Table 3A-3 the states with the largest NO<sub>x</sub> emissions reductions in the final rule case are at the top of the list. Examining the emissions data in Table 3A-3 together with the ppb impacts in Table 3A-1 and 3A-2 indicates that the largest reductions in receptor design values are projected to occur near and downwind of the states with the largest reductions in ozone season EGU+non-EGU NO<sub>x</sub> emissions.

**Table 3A-1. Ozone Impacts at Projected Nonattainment and Maintenance-Only Receptors (ppb) for the Final Rule Modeled Control Case in 2026**

Site ID	State	County	Final Rule Case
40278011	Arizona	Yuma	-0.06
60650016	California	Riverside	-0.06
60651016	California	Riverside	-0.08
80350004	Colorado	Douglas	-0.17
80590006	Colorado	Jefferson	-0.14
80590011	Colorado	Jefferson	-0.11
80690011	Colorado	Larimer	-0.24
90010017	Connecticut	Fairfield	-0.38
90013007	Connecticut	Fairfield	-0.45
90019003	Connecticut	Fairfield	-0.46
90099002	Connecticut	New Haven	-0.43
170310001	Illinois	Cook	-0.08
170314201	Illinois	Cook	-0.09
170317002	Illinois	Cook	-0.11
350130021	New Mexico	Dona Ana	-0.02
350130022	New Mexico	Dona Ana	-0.03
350151005	New Mexico	Eddy	-0.02
350250008	New Mexico	Lea	-0.02
480391004	Texas	Brazoria	-0.82
481210034	Texas	Denton	-0.42
481410037	Texas	El Paso	-0.03
481671034	Texas	Galveston	-0.92
482010024	Texas	Harris	-0.68
482010055	Texas	Harris	-0.75
482011034	Texas	Harris	-0.72

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Site ID	State	County	Final Rule Case
482011035	Texas	Harris	-0.70
490110004	Utah	Davis	-0.22
490353006	Utah	Salt Lake	-0.22
490353013	Utah	Salt Lake	-0.15
550590019	Wisconsin	Kenosha	-0.21
551010020	Wisconsin	Racine	-0.22
551170006	Wisconsin	Sheboygan	-0.30

**Table 3A-2. Ozone Impacts at Violating-Monitor Maintenance-Only Receptors (ppb) for the Final Rule Modeled Control Case in 2026**

Site ID	State	County	Final Rule Case
40070010	Arizona	Gila	-0.07
40130019	Arizona	Maricopa	-0.04
40131003	Arizona	Maricopa	-0.05
40131004	Arizona	Maricopa	-0.05
40131010	Arizona	Maricopa	-0.05
40132001	Arizona	Maricopa	-0.04
40132005	Arizona	Maricopa	-0.06
40133002	Arizona	Maricopa	-0.04
40134004	Arizona	Maricopa	-0.05
40134005	Arizona	Maricopa	-0.04
40134008	Arizona	Maricopa	-0.05
40134010	Arizona	Maricopa	-0.06
40137020	Arizona	Maricopa	-0.04
40137021	Arizona	Maricopa	-0.06
40137022	Arizona	Maricopa	-0.05
40137024	Arizona	Maricopa	-0.04
40139702	Arizona	Maricopa	-0.05
40139704	Arizona	Maricopa	-0.06
40139997	Arizona	Maricopa	-0.04
40218001	Arizona	Pinal	-0.03
80013001	Colorado	Adams	-0.13
80050002	Colorado	Arapahoe	-0.18
80310002	Colorado	Denver	-0.13
80310026	Colorado	Denver	-0.13
90079007	Connecticut	Middlesex	-0.49
90110124	Connecticut	New London	-0.41
170310032	Illinois	Cook	-0.10

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Site ID	State	County	Final Rule Case
170311601	Illinois	Cook	-0.10
181270024	Indiana	Porter	-0.23
260050003	Michigan	Allegan	-0.39
261210039	Michigan	Muskegon	-0.50
320030043	Nevada	Clark	-0.15
350011012	New Mexico	Bernalillo	-0.04
350130008	New Mexico	Dona Ana	-0.02
361030002	New York	Suffolk	-0.39
390850003	Ohio	Lake	-0.70
480290052	Texas	Bexar	-0.28
480850005	Texas	Collin	-0.48
481130075	Texas	Dallas	-0.45
481211032	Texas	Denton	-0.41
482010051	Texas	Harris	-0.69
482010416	Texas	Harris	-0.73
484390075	Texas	Tarrant	-0.30
484391002	Texas	Tarrant	-0.38
484392003	Texas	Tarrant	-0.38
484393009	Texas	Tarrant	-0.32
490571003	Utah	Weber	-0.27
550590025	Wisconsin	Kenosha	-0.22
550890008	Wisconsin	Ozaukee	-0.24

**Table 3A-3. Impact on EGU and Non-EGU Ozone Season NO<sub>x</sub> Emissions by State in the 2026 Modeled Control Case (1,000 tons)**

State	Final - Baseline
Louisiana	-12.6
Oklahoma	-9.9
Texas	-7.7
Arkansas	-7.3
Missouri	-6.9
Michigan	-5.3
Kentucky	-5.3
Utah	-5.2
Ohio	-4.9
West Virginia	-3.7
Indiana	-3.1
Mississippi	-3.0

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State	Final - Baseline
Pennsylvania	-2.1
Illinois	-2.1
California	-1.7
Virginia	-1.6
Tribal	-1.3
Minnesota	-1.2
New York	-1.2
New Jersey	-0.3
Arizona	-0.3
Alabama	-0.2
Maryland	-0.1
Nevada	0.0
Rhode Island	0.0
Florida	0.0
Maine	0.0
Oregon	0.0
Vermont	0.0
District of Columbia	0.0
Washington	0.0
Montana	0.0
Delaware	0.0
Massachusetts	0.0
New Hampshire	0.0
New Mexico	0.0
Connecticut	0.0
Tennessee	0.0
South Dakota	0.0
Georgia	0.0
Nebraska	0.1
Idaho	0.1
Colorado	0.1
North Dakota	0.1
Wisconsin	0.1
South Carolina	0.2
Iowa	0.3
North Carolina	0.4
Kansas	0.4
Wyoming	0.5

## **CHAPTER 4: COST, EMISSIONS, AND ENERGY IMPACTS**

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### **Overview**

This chapter reports the compliance costs, emissions, and energy analyses performed for the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS). The EPA used the Integrated Planning Model (IPM)<sup>63</sup> to conduct the electric generating units (EGU) analysis discussed in this chapter and information from the Control Measures Database (CMDB)<sup>64</sup> and the 2019 emissions inventory to conduct analysis for non-electric generating units (non-EGUs) for 2026. As explained in detail below, this chapter presents analysis for three regulatory control alternatives that differ in the level of EGU nitrogen oxides (NO<sub>x</sub>) ozone season emissions budgets in the 22 states subject to this action beginning in 2023. These regulatory control alternatives impose different budget levels for EGUs. The different budget levels are calculated assuming the application of different NO<sub>x</sub> mitigation technologies. The analysis for EGUs in the chapter does not include effects from certain provisions of the Inflation Reduction Act (IRA) of 2022 in the baseline. The effects of accounting for the IRA on the power sector costs, emission reductions and other impacts of this final rule are provided in a sensitivity analysis presented in Appendix 4A. The chapter also presents three regulatory control alternatives for non-EGUs that differ in the control technologies assumed to be adopted for compliance.

The chapter is organized as follows: following a summary of the regulatory control alternatives analyzed and a summary of the EPA’s methodologies, we present estimates of compliance costs for EGUs, as well as estimated impacts on emissions, generation, capacity, fuel use, fuel price, and retail electricity price for a few years. We then present a summary of the results of the non-EGU assessment for 2026. Section 4.6 of this chapter describes the relationship between the compliance cost estimates and social costs.

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<sup>63</sup> Information on IPM can be found at the following link: <https://www.epa.gov/airmarkets/power-sector-modeling>.

<sup>64</sup> 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>.



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#### **4.1 Regulatory Control Alternatives**

This rule establishes NO<sub>x</sub> emissions budgets requiring fossil fuel-fired electric generating units (EGUs) in 22 states to participate in an allowance-based ozone season (May 1 through September 30) trading program beginning in 2023. The EGUs covered by the FIPs and subject to the budget are fossil-fired EGUs with >25-megawatt (MW) capacity. For details on the derivation of these budgets, please see Section V.C. of the preamble.

The FIP requirements establish ozone season NO<sub>x</sub> emissions budgets for 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) and require EGUs in these states to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) NO<sub>x</sub> Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.<sup>65</sup> The EPA is amending existing FIPs for 12 states currently participating in the CSAPR NO<sub>x</sub> Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) to replace their existing emissions budgets established in the Revised CSAPR Update (with respect to the 2008 ozone NAAQS) with new emissions budgets. For seven states currently covered by the CSAPR NO<sub>x</sub> 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<sub>x</sub> ozone season trading program: Minnesota, Nevada, and Utah.

In this rule, we introduce additional features to the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets over time and a backstop daily emission rate for most coal-fired units, along with an adjustment to the total size of the allowance bank, which is 21 percent of the sum of the state emissions budgets for the

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<sup>65</sup> As explained in Section V.C.1 of the preamble, 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.

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current control period until 2030 (at which point it declines to 10.5%), that were not included in previous CSAPR NO<sub>x</sub> ozone season trading programs. These enhancements will help maintain control stringency over time and improve emissions performance at individual units, offering an extra measure of assurance that existing pollution controls will be operated during the ozone season. This analysis incorporates the daily emission rate requirement for units with existing controls by forcing operation of these controls in the ozone season for affected sources starting in the 2023 run year (although the rule would not impose some of these limits until 2024).

The additional EGU emissions reductions<sup>66</sup> beginning in 2026 are based on the feasibility of control installation for EGUs in 19 states (19-state region) that remain linked to downwind nonattainment and maintenance receptors in 2026.<sup>67</sup> Starting in 2030, consistent with the structure of the final rule, this analysis imposes the backstop emission rate for certain larger coal-fired units that do not already have SCR installed, which forces these units identified as having SCR retrofit potential to either install new SCR retrofits, find other means of compliance, or retire.<sup>68</sup> The analysis does not explicitly capture the dynamic budget adjustments over time in the modeling, but the forced operation of controls during the ozone season over the forecast period (even in the absence of binding mass limits) approximates this feature of the program design.<sup>69</sup> For details of the controls modeled for each of the regulatory control alternatives please see

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<sup>66</sup> The model was not explicitly constrained to limit the bank to 21% of the sum of state budgets in the first period and 10.5% thereafter. However, the model solve was reviewed to ensure that any allowances withdrawn from the bank did not violate this threshold. If this condition had been violated (which did not occur for these runs), the model would have been re-run with an additional limit incorporated.

<sup>67</sup> For EGUs, the 19 states linked in 2026 include 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 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 the EPA's assumed EGU SCR retrofit mitigation technologies.

<sup>68</sup> The rule assumes SCR retrofit potential starting in 2026, and this is reflected in the 2026/27 state emission budgets. The daily backstop emission rate does not apply for large coal units that do not already have SCR controls until the second ozone season after they install the control or by 2030 at the latest. The EPA's IPM model run years are 2025, 2028 and 2030. The SCR compliance behavior is generally expected to occur no later than 2030. Therefore, the EPA models this daily backstop emission rate in 2030 (when choosing between model run year 2025 and 2028) while imposing 2026 and 2027 SCR-retrofit-related emission reductions reflected in those control periods' emission budgets in the model run-year 2025 to model compliance cost in the first years by which the technology may be put into place for some units. (In this case, we are treating 2025 as sufficiently reflective of conditions in 2026 to be usable for this RIA analysis.)

<sup>69</sup> In years in which the dynamic budgets are implemented, the budgets would be calculated based on historical heat input data and assuming optimization of existing controls as well as installation of the controls required by the rule. While the modeling does not include lower budgets in response to modeled declines in heat input, forcing existing controls to operate in an environment of fluctuating future heat input approximates the underlying behavior and captures the associated costs.

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Table 4-2 below.

This rule also includes NO<sub>x</sub> emissions limitations with an initial compliance date of 2026 applicable to certain non-EGU stationary 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. **Error! Reference source not found.** presents the industries, emissions unit types, form of emissions limit, and NO<sub>x</sub> emissions limitations for the final rule. For the less and more stringent alternatives, specific emission limits are not identified, and certain control technologies are assumed for compliance with emissions limits that would be more or less stringent than the final rule.

**Table 4-1. Summary of Non-EGU Industries, Emissions Unit Types, Form of Final Emissions Limits, and Final Emissions Limits**

Industry	Emissions Unit Type	Form of Final Emissions Limits	Final Emissions Limits
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engines	Grams per horsepower per hours (g/hp-hr)	Four Stroke Rich Burn: 1.0 g/hp-hr Four Stroke Lean Burn: 1.5 g/hp-hr Two Stroke Lean Burn: 3.0 g/hp-hr
Cement and Concrete Product Manufacturing	Kilns	Pounds per ton (lbs/ton) of clinker	Long Wet: 4.0 lb/ton Long Dry: 3.0 lb/ton Preheater: 3.8 lb/ton Precalciner: 2.3 lb/ton Preheater/Precalciner: 2.8 lb/ton
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	lbs NO <sub>x</sub> per/ton of steel and lbs/mmBtu <sup>a</sup>	Test and set limit based on installation of Low-NO <sub>x</sub> Burners
Glass and Glass Product Manufacturing	Furnaces	lbs/ton glass produced	Container Glass Furnace: 4.0 lb/ton Pressed/Blown Glass Furnace: 4.0 lb/ton Fiberglass Furnace: 4.0 lb/ton Flat Glass Furnace: 9.2 lb/ton
Iron and Steel Mills and Ferroalloy Manufacturing Metal Ore Mining Basic Chemical Manufacturing Petroleum and Coal Products Manufacturing Pulp, Paper, and Paperboard Mills	Boilers	lbs/mmBtu <sup>a</sup>	Coal: 0.20 lb/mmBtu Residual Oil: 0.20 lb/mmBtu Distillate Oil: 0.12 lb/mmBtu Natural Gas: 0.08 lb/mmBtu
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ppmvd on a 24-hour averaging period and ppmvd on a 30-day averaging period	110 ppmvd on a 24-hour averaging period 105 ppmvd on a 30-day averaging period

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<sup>a</sup> Heat input limit.

This regulatory impact analysis (RIA) evaluates the benefits, costs and certain impacts of compliance with three regulatory control alternatives: the Transport FIP for the 2015 ozone NAAQS, a less-stringent alternative, and a more-stringent alternative. Table 4-2 below presents the less stringent alternatives, final rule requirements, and more stringent alternatives for EGUs and non-EGUs. For the purposes of summarizing the results of the benefits and costs of these alternatives, the less stringent alternative for EGUs is presented with the less stringent alternative for non-EGUs. However, the cost, emissions, and energy impacts for the EGU and non-EGU alternatives are evaluated separately.

**Table 4-2. Regulatory Control Alternatives for EGUs and Non-EGUs**

<b>Regulatory Control Alternative</b>	<b>NO<sub>x</sub> Controls Implemented for EGUs within IPM<sup>a,b</sup></b>
Less Stringent Alternative	1) 2023 onwards: Fully operate existing selective catalytic reduction (SCRs) during ozone season
	2) 2023 onwards: Fully operate existing selective non-catalytic reduction (SNCRs) during ozone season
	3) In 2023 install state-of-the-art combustion controls <sup>c</sup>
	4) In 2030 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls. <sup>d</sup>
Final Rule	(All Controls above and) 5) In 2025 model run year, impose Engineering Analysis derived emissions budgets that assume installation of SCR controls on coal units greater than 100 MW within the 19-state region that lack SCR controls.
More Stringent Alternative	(Controls 1 – 5 above and) 6) In 2025 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls, forcing units to retrofit or retire.
<b>Regulatory Control Alternative</b>	<b>NO<sub>x</sub> Emissions Limits for Non-EGUs – Emissions Unit Types, Industries, and Controls Assumed for Compliance</b>
Less Stringent Alternative	1) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – Adjust Air-to-Fuel Ratio
	2) Kilns in Cement and Cement Product Manufacturing – install SNCR
	3) Reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing – install Low NO <sub>x</sub> burners (LNB)
	4) Furnaces in Glass and Glass Product Manufacturing – install LNB
	5) 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 – install SNCR
	6) Combustors or Incinerators in Solid Waste Combustors and Incinerators – install Advanced NSCR (ANSCR) or LN <sup>TM</sup> and SNCR <sup>e</sup>
Final Rule	(Controls 2, 3, 4, and 6 above, plus changes in assumed controls noted below) 7) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – depending on engine type, install <i>Layered Combustion, non-selective catalytic reduction (NSCR), or SCR</i> 8) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products

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	Manufacturing, and Pulp, Paper, and Paperboard Mills – install SCR (coal- or oil-fired) or LNB and FGR (natural gas-fired only)
	(Controls 3, 6, 7 above, plus changes in assumed controls noted below)
More Stringent Alternative	9) Kilns in Cement and Cement Product Manufacturing – install SCR
	10) Furnaces in Glass and Glass Product Manufacturing – install SCR
	11) 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 – install SCR (natural gas-fired only)

<sup>a</sup> IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. For this analysis, IPM maps the calendar year 2023 to run year 2023, calendar years 2024-2026 to run year 2025 and calendar years 2027-2029 to run year 2028. For model details, please see Chapter 2 of the IPM documentation.

<sup>b</sup> NOx mass budgets are imposed in all run years in IPM (2023-2050) consistent with the measures highlighted in this table.

<sup>c</sup> The final rule implementation allows for the reduction associated with state-of-the-art combustion controls to occur by 2024. It is captured in 2023 in this analysis to fully assess the impact of the mitigation measures occurring prior to 2026.

<sup>d</sup> For the 19 states with EGU obligations that are linked in 2026 the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam-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 units greater than 100 MW that have historically emitted at least 150 tons of NOx per ozone season. 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 the EPA’s assumed EGU SCR retrofit mitigation technologies. The 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.

<sup>e</sup> Covanta has developed a proprietary low NOx combustion system (LN<sup>TM</sup>) that involves staging of combustion air. The system is a trademarked system and Covanta has received a patent for the technology.

#### 4.1.1 EGU Regulatory Control Alternatives Analyzed

The illustrative emission budgets in this RIA represent EGU NOx ozone season emission budgets for each state in 2023 and in 2026.<sup>70</sup> This RIA analyzes the Transport FIP for the 2015 ozone NAAQS emission budgets, as well as a more and a less stringent alternative to the Transport FIP for the 2015 ozone NAAQS. The more and less stringent alternatives differ from the final rule in that they set different NOx ozone season emission budgets for the affected EGUs and different dates for compliance with the backstop emission rate. All three scenarios use emission budgets that were developed using uniform control stringency represented by \$900 per ton of NOx (2016\$) in 2023 (i.e., optimizing existing controls and installation of state-of-the-art combustion controls). The final rule and more stringent alternative use emission budgets that

<sup>70</sup> Mapping each year in the analysis time period to a representative model run year enables IPM to perform multiple year analyses while keeping the model size manageable. IPM considers the costs in all years in the planning horizon while reporting results only for model run years. Run year 2023 is mapped to calendar year 2023, while run year 2025 is mapped to 2024-26, run year 2028 is mapped to 2027-29, run year 2030 is mapped to 2030-31, run year 2035 is mapped to 2032-37, run year 2040 is mapped to 2038-42, while run year 2045 is mapped to 2043-47.

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were developed using a uniform control stringency represented by \$11,000 per ton of NO<sub>x</sub> (2016\$) in 2025 (i.e., installation of SCR and SNCR post-combustion controls), while the less stringent alternative uses emissions budgets that were developed using a uniform control stringency represented by \$11,000 per ton of NO<sub>x</sub> (2016\$) in 2030. The final rule and less-stringent alternative defer the backstop emission rate to the 2030 run year, while the more stringent alternative imposes the backstop emission rate in the 2025 run year (reflective of imposition in the 2026 calendar year). The backstop emission rate is imposed by the relevant run year (2025 or 2030 depending on alternative) on all coal units within the 19-state region that are greater than 100 MW and lack SCR controls (excepting circulating fluidized bed (CFB) units).

The state emission budgets in this RIA are illustrative for several reasons. First, they reflect an estimate of the future budget based on the EPA's preset budget methodology. However, as described in the preamble, the implemented state budget may be either the preset budget or the dynamic budget starting in 2026. As noted above, other parameters are used to capture the dynamic budget impacts in this modeling, as the future heat input needed to derive that budget number is not yet known. Second, the budgets are illustrative as the utilized 2023 preset budgets reflect full implementation of existing control optimization and upgrade to state-of-the-art combustion control potential. However, the final rule state emission budgets and implementation allows the limited number of reductions related to state-of-the-art combustion control to be realized up through 2024. Finally, the illustrative budgets in this RIA were derived using draft results from the EPA's data and engineering analysis up through October 2022. The preset budgets reflected in the final rule are slightly different in some cases due to new data or comment incorporation that occurred between October of 2022 and January 2023. The Agency conducted additional sensitivity analysis using IPM demonstrating that the substituting in the final preset state emission budgets instead of the illustrative ones modeled made no significant difference in the cost implications described in the body of the RIA. The analysis is provided in the docket for this rulemaking.

The three illustrative regulatory control alternatives presented in this RIA provide a reasonable approximation of the impacts of the rule, as well as an evaluation of the relative impacts of two regulatory alternatives. Table 4-3. reports the illustrative EGU NO<sub>x</sub> ozone season emission budgets that are evaluated in this RIA for the 2023 – 2030 IPM run years-. As described

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above, starting in 2023, IPM is constrained to disallow emissions from affected EGUs in the 22 states to exceed the sum of emissions budgets but for the ability to use banked allowances from previous years for compliance. For individual states, IPM is constrained to disallow emissions from exceeding 121% of the state emission budget (the assurance levels). In the IPM modeling of these RIA alternatives, no further reductions in budgets occur after 2030, and budgets remain in place for future years.<sup>71</sup> These budgets are imposed in addition to the control measures outlined in Table 4-2.

**Table 4-3. Illustrative NO<sub>x</sub> Ozone Season Emission Budgets (Tons) Evaluated by IPM Run Year**

Region	Final Rule and More Stringent Alternative				Less Stringent Alternative			
	2023	2025	2028	2030	2023	2025	2028	2030
Alabama	6,595	6,236	6,236	4,610	6,595	6,236	6,236	4,610
Arkansas	8,927	4,031	4,031	3,582	8,927	8,700	8,700	3,582
Illinois	7,474	5,363	4,555	4,050	7,474	6,415	4,985	4,050
Indiana	12,440	8,633	8,633	6,307	12,440	9,658	9,658	6,307
Kentucky	13,204	7,862	7,862	7,679	13,204	12,515	12,515	7,679
Louisiana	9,311	3,864	2,969	2,969	9,311	9,089	6,684	2,969
Maryland	1,206	592	592	592	1,206	592	592	592
Michigan	10,275	5,997	5,997	5,691	10,275	8,626	8,626	5,691
Minnesota	5,504	2,905	2,905	1,663	5,504	2,905	2,905	1,663
Mississippi	5,024	1,859	1,527	1,527	5,024	4,763	2,817	1,527
Missouri	12,598	7,329	7,329	6,770	12,598	11,063	11,063	6,770
Nevada	2,391	1,051	1,051	818	2,391	1,051	1,051	818
New Jersey	768	768	768	768	768	768	768	768
New York	3,858	3,333	3,333	3,333	3,858	3,858	3,858	3,333
Ohio	9,134	7,953	6,934	6,399	9,134	7,953	6,934	6,399
Oklahoma	10,271	3,842	3,842	3,842	10,271	9,044	9,044	3,842
Pennsylvania	8,918	7,146	7,146	4,816	8,918	8,691	8,691	4,816
Texas	40,294	22,964	22,407	21,631	40,294	36,173	34,678	21,631
Utah	15,755	2,604	2,604	2,604	15,755	9,934	9,934	2,604
Virginia	3,065	2,373	2,373	1,951	3,065	2,756	2,756	1,951
West Virginia	13,306	9,678	9,678	9,678	13,306	11,958	11,958	9,678
Wisconsin	6,295	3,407	3,407	3,407	6,295	3,407	3,407	3,407

<sup>71</sup> In 2030 onwards, dynamic budgets may cause the budgets to decrease. While the EPA does not model this feature, the assumption of continued optimization of existing controls approximates compliance behavior and associated costs that would result from dynamic budgets.

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Region	Final Rule and More Stringent Alternative				Less Stringent Alternative			
	2023	2025	2028	2030	2023	2025	2028	2030
Aggregated State Emission Budgets	206,616	119,789	116,178	104,685	206,616	176,153	167,860	104,685

Note that EGUs have flexibility in determining how they will comply with the allowance trading program. As discussed below, the way that they comply may differ from the methods forecast in the modeling for this RIA. See Section 4.3 for further discussion of the modeling approach used in the analysis presented below.

4.1.2 Non-EGU Regulatory Control Alternatives Analyzed

As discussed in Section I.B. of the preamble and Sections 4.4 and 4.5 below, we used 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 per ton values from the control measures database (CMDDB), to estimate NO<sub>x</sub> emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. The EPA did not estimate emissions reductions of SO<sub>2</sub>, PM<sub>2.5</sub>, CO<sub>2</sub> and other pollutants that may be associated with controls on non-EGU emissions units. For details about the non-EGU assessment and 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.<sup>72</sup>

The rule imposes emissions limits on each of the emission unit types identified in Table 4-1. The less stringent alternative assumes less stringent control technologies for the reciprocating internal combustion engines in Pipeline Transportation of Natural Gas and 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 relative to the final rule. The more stringent alternative assumes more stringent control technologies for the kilns in Cement and Concrete Products Manufacturing, the furnaces in Glass

**Commented [EO 1286641]:** What kind of comments did EPA receive on non-EGU source costs? The RIA is silent on this issue, including the admission that recordkeeping and monitoring costs are not included (which can be costly if sources are required to use CEMS). Presumably EPA is providing this information in the preamble. EPA should provide a summary of this information in the RIA.

**Commented [EPA42R41]:** The EPA received some industry-specific control technology cost estimates. The comments primarily questioned the feasibility of the controls but also stated the costs were underestimated. While limited example calculations were provided, we are unable to verify the validity of these calculations or determine if they are more accurate than those estimated by EPA. Regardless, there is not enough information contained in the comments to re-estimate the costs. The information in the comments will be used to inform future improvements to our cost estimating procedures.

Also, many of the comments focused on the \$7,500 marginal cost-per-threshold used in the non-EGU screening assessment and how controls for their emissions units exceeded that value. Sections V.C.2 and V.D.2 of the preamble discuss the role of the representative cost-per-ton values used for EGUs and non-EGUs.

<sup>72</sup> <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668>



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and Glass Products Manufacturing, and the natural gas-fired 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 relative to the final rule. Table 4-4 below provides a summary of the 2019 ozone season emissions for non-EGUs for the 20 states subject to the FIP in 2026, along with the estimated ozone season reductions for the final rule and the less and more stringent alternatives.

**Table 4-4. Ozone Season NO<sub>x</sub> Emissions and Emissions Reductions for the Final Rule and the Less and More Stringent Alternatives for Non-EGUs**

State	2019 Ozone Season Emissions <sup>a</sup>	Final Rule: Ozone Season NO <sub>x</sub> Reductions	Less Stringent: Ozone Season NO <sub>x</sub> Reductions	More Stringent: Ozone Season NO <sub>x</sub> Reductions <sup>b</sup>
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
NJ	2,078	242	242	258
NV	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
<b>Totals</b>	<b>302,425</b>	<b>44,616</b>	<b>16,786</b>	<b>67,728</b>

<sup>a</sup> 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.

<sup>b</sup> Note that for some industries the more stringent alternative reflects assumed technologies (and estimated emissions reductions) that are not widely demonstrated in practice in the U.S.

#### 4.2 Power Sector Modeling Framework

IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and to examine

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prospective air pollution control policies throughout the contiguous United States for the entire electric power system. The EPA used IPM to project likely future electricity market conditions with and without the Transport FIP for the 2015 ozone NAAQS.

IPM, developed by ICF, is a multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides estimates of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. Due to lack of lead time, the EPA does not allow IPM to build certain new capital investments such as new, unplanned natural gas or renewable capacity or new SCR or SNCR through the 2023 run year in response to the state emission budgets (i.e., retrofits, retirements or builds additional to those selected in the baseline are not allowed in 2023). The compliance analysis of the final rule and alternatives assumes new combustion controls in the 2023 analysis year (although the rule would require these in 2024). After 2023, this limit is relaxed, and the model is no longer prevented from undertaking these capital investments.

The EPA has used IPM for almost three decades to better understand power sector behavior under future business-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.<sup>73</sup>

The model incorporates a detailed representation of the fossil-fuel supply system that is used to estimate equilibrium fuel prices. The model uses natural gas fuel supply curves and regional gas delivery costs (basis differentials) to simulate the fuel price associated with a given

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<sup>73</sup> Detailed information and documentation of EPA's Baseline run using IPM (v6), including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: <https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case>.

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level of gas consumption within the system. These inputs are derived using ICF’s Gas Market Model (GMM), a supply/demand equilibrium model of the North American gas market.<sup>74</sup>

IPM also endogenously models the partial equilibrium of coal supply and EGU coal demand levels throughout the contiguous U.S., taking into account assumed non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 14 coal grades, and the coal transport network, which consists of over four thousand linkages representing rail, barge, and truck, and conveyer linkages. The coal supply curves in IPM were developed during a thorough bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants would face if selecting that coal over the modeling time horizon. The IPM documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 36 coal regions’ supply curves.<sup>75</sup>

To estimate the annualized costs of additional capital investments in the power sector, 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. The CRF is derived from estimates of the power sector’s cost of capital (i.e., private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital.<sup>76</sup> It is important to note that there is no single CRF factor applied in the model; rather, the CRF varies across technologies, book life of the capital investments, and regions in the model in order to better simulate power sector decision-making.

The EPA has used IPM extensively over the past three decades to analyze options for reducing power sector emissions. Previously, the model has been used to estimate the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule (U.S. EPA, 2005), the Cross-State Air Pollution Rule (U.S. EPA, 2011), the Mercury and Air Toxics Standards

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<sup>74</sup> See Chapter 8 of EPA’s Baseline run using IPM v6 documentation, available at: <https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case>.

<sup>75</sup> See Chapter 7 of the IPM v6 documentation. The documentation for EPA’s power sector modeling platform v6 - summer 2021 reference case consists of a comprehensive document for the Summer 2021 release of IPM v. 6.20 and is available at: <https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case>.

<sup>76</sup> See Chapter 10 of the documentation for EPA’s power sector modeling platform v6 - summer 2021 reference case, available at: <https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case>

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(U.S. EPA, 2011a), the Clean Power Plan for Existing Power Plants (U.S. EPA, 2015), the Carbon Pollution Standards for New Power Plants (U.S. EPA, 2015a), the Cross-State Air Pollution Rule Update (U.S. EPA, 2016), the Affordable Clean Energy Rule (U.S. EPA, 2019), the Clean Power Plan Repeal (U.S. EPA, 2019), and the Revised Cross-State Air Pollution Update Rule (U.S. EPA, 2021). The EPA has also used IPM to estimate the air pollution reductions and power sector impacts of water and waste regulations affecting EGUs, including Cooling Water Intakes (316(b)) Rule (U.S. EPA, 2014), Disposal of Coal Combustion Residuals from Electric Utilities (U.S. EPA, 2015b), Steam Electric Effluent Limitation Guidelines (ELG) (U.S. EPA, 2015c), and Steam Electric Reconsideration Rule (U.S. EPA, 2020).

The model and the EPA’s input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, in October 2014 U.S. EPA commissioned a peer review<sup>77</sup> of EPA Baseline run version 5.13 using the Integrated Planning Model. Additionally, and in the late 1990s, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies.<sup>78</sup> The Agency has also used the model in a number of comparative modeling exercises sponsored by Stanford University’s Energy Modeling Forum over the past 20 years. IPM has also been employed by states (e.g., for the Regional Greenhouse Gas Initiative, the Western Regional Air Partnership, Ozone Transport Assessment Group), other Federal and state agencies, environmental groups, and industry.

#### **4.3 The EPA’s Power Sector Modeling of the Baseline run and Three Regulatory Control Alternatives**

The IPM “baseline run” for any regulatory impact analysis is a business-as-usual scenario that represents expected behavior in the electricity sector under market and regulatory conditions

<sup>77</sup> See Response and Peer Review Report EPA Baseline run Version 5.13 Using IPM, available at: <https://www.epa.gov/airmarkets/response-and-peer-review-report-epa-base-case-version-513-using-ipm>.

<sup>78</sup> <http://www2.epa.gov/clean-air-act-overview/benefits-and-costs-clean-air-act>

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in the absence of a regulatory action. As such, an IPM baseline run represents an element of the baseline for this RIA.<sup>79</sup> The EPA frequently updates the IPM baseline run to reflect the latest available electricity demand forecasts from the U.S. Energy Information Administration (EIA) as well as expected costs and availability of new and existing generating resources, fuels, emission control technologies, and regulatory requirements.

#### 4.3.1 The EPA's IPM Baseline run v.6.20

For our analysis of the final Transport FIP for the 2015 ozone NAAQS, the EPA used an updated version of the Summer 2021 release of IPM version 6.20 to provide power sector emissions data for air quality modeling, as well as a companion updated database of EGU units (the National Electricity Energy Data System, or NEEDS, Summer 2022<sup>80</sup>) that is used in the EPA's modeling applications of IPM. The IPM Baseline run includes the CSAPR, CSAPR Update, and the Revised CSAPR Update, as well as the Mercury and Air Toxics Standards. The Baseline run also includes the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the finalized 2020 ELG and CCR rules.<sup>81</sup> While finalized in December 2021, the impacts of the 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards are not captured in the baseline; the rule includes requirements for model years 2023 through 2026. The impacts of the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review are also not captured in the baseline.<sup>82</sup> Additionally, the model was also updated to account for current elevated input fuel pricing, with natural gas prices in the 2023 and 2025 run years hardwired based on futures prices,<sup>83</sup> and coal prices escalated in

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<sup>79</sup> As described in Chapter 5 of EPA's *Guidelines for Preparing Economic Analyses*, the baseline "should incorporate assumptions about exogenous changes in the economy that may affect relevant benefits and costs (e.g., changes in demographics, economic activity, consumer preferences, and technology), industry compliance rates, other regulations promulgated by EPA or other government entities, and behavioral responses to the proposed rule by firms and the public." (USEPA, 2010).

<sup>80</sup> <https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.20>

<sup>81</sup> For a full list of modeled policy parameters, please see:

<https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case>

<sup>82</sup> Available at: <https://www.federalregister.gov/documents/2021/11/15/2021-24202/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for>

<sup>83</sup> 2023 and 2025 Henry Hub gas prices were exogenously input based on the average of the daily values of the NYMEX Natural Gas Henry Hub Annual Strip over the 5/09/22 – 6/21/22 period, which reflected the most recent set of values available at the time of this analysis. Hence the price of natural gas in these run years is derived based on futures pricing and not a solved for output. Subsequent years reflect fundamentals-based pricing.

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the 2023 run year. The model runs for the main RIA analysis do not capture the impacts of the Inflation Reduction Act (IRA). Appendix 4A includes a representation of key IRA provisions in the baseline and under a scenario that includes the final rule as modeled here, along with the associated costs and emission reductions. The analysis of power sector cost and impacts presented in this chapter is based on a single IPM Baseline run, and represents incremental impacts projected solely as a result of compliance with the emissions budgets presented in Table 4-3. above and the backstop emission rate.

#### 4.3.2 Methodology for Evaluating the Regulatory Control Alternatives

To estimate the costs, benefits, and economic and energy market impacts of the Transport FIP for the 2015 ozone NAAQS, the EPA conducted quantitative analysis of the three regulatory control alternatives: the Transport FIP for the 2015 ozone NAAQS emission budgets and a more and a less stringent alternative. Details about these regulatory control alternatives, including state-specific EGU NO<sub>x</sub> ozone-season emissions budgets for each alternative as analyzed in this RIA, are provided above in Section 4.1.

Before undertaking power sector analysis to evaluate compliance with the regulatory control alternatives, the EPA first considered available EGU NO<sub>x</sub> mitigation strategies that could be implemented for the 2023 ozone season. The EPA considered all widely-used EGU NO<sub>x</sub> control strategies: optimizing<sup>84</sup> NO<sub>x</sub> removal by existing operational selective catalytic reduction (SCRs) and turning on and optimizing existing idled SCRs; optimizing existing idled selective non-catalytic reduction (SNCRs); installation of (or upgrading to) state-of-the-art NO<sub>x</sub> combustion controls; and installing new SCRs and SNCRs. The EPA determined that affected EGUs within the 22 states could implement the NO<sub>x</sub> mitigation strategies based on optimization of existing controls for the 2023 ozone season.<sup>85</sup> (The final rule does not phase in reductions associated with upgraded combustion controls until 2024, but the modeling for this RIA assumes this control strategy in the 2023 run year.) After assessing the available NO<sub>x</sub> mitigation methods, this RIA projects the system-wide least-cost strategies for complying with the annual budgets and the backstop emission rate. Least-cost compliance may lead to the application of different

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<sup>84</sup> Optimization of controls refers to the process of fully operating controls in order to meet the “widely achievable emission rate” as outlined in the EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD.

<sup>85</sup> The analysis assumes that SNCR and SCR optimization and state-of-the-art combustion control installation is available starting in 2023 and is adopted by all units identified by the Engineering Analysis. This compliance choice is an exogenous input into IPM.

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control strategies at a given source compared to the particular control measure assumed for that source in the analysis used to calculate the budgets, which is in keeping with the cost-saving compliance flexibility afforded by this allowance trading program.

Within IPM, units are assigned NO<sub>x</sub> emission rates based on historical data. To account for changes in emission rates based on the seasonal operation of controls, each unit is assigned four modes of operation. When the model is run, IPM selects the appropriate mode for each season based on historical data (i.e., how the unit operated in the past), whether the unit is subject to any seasonal or annual NO<sub>x</sub> reduction requirements, and whether the unit installs any additional controls.<sup>86</sup> The rule's emission control requirements for EGUs only apply during the program's ozone season (May 1 through September 30).

Many of these mitigation strategies are captured within IPM. However, due to limitations on model size, IPMv.6.20 does not have the ability to endogenously determine whether to operate existing EGU post-combustion NO<sub>x</sub> controls (i.e., SCR or SNCR), optimize existing SCRs and SNCRs, and install combustion controls in response to a regulatory emissions requirement.<sup>87</sup> The treatment of these controls in the analyses are described in turn. The operating status of existing post-combustion NO<sub>x</sub> controls at a particular EGU in a model scenario is determined by the model user. In order to evaluate compliance with the regulatory alternatives, the EPA determined outside of IPM the operation of existing controls that are idle in the baseline that would be expected for compliance with each of the evaluated regulatory alternatives and for which model years they can feasibly be applied. The EPA considers a unit to have optimized use of an SCR if emissions rates are equal to (or below) the “widely achievable” rate of 0.08 lbs/MMBtu for coal steam units, 0.03 lbs/MMBtu for oil/gas and combustion turbine units, and 0.012 lb/MMBtu for combined cycle units.<sup>88</sup> Within IPM, units with partially operating or idled SCRs are defined as SCR-equipped units with ozone season NO<sub>x</sub> emission rates exceeding the optimized rates in the baseline run. These units had their emission rates lowered to the applicable “widely achievable” optimized emissions rate. These control options

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<sup>86</sup> For details on the emission rate assumptions within the model, please refer to chapter 3 of the IPM documentation available at: <https://www.epa.gov/system/files/documents/2021-09/epa-platform-v6-summer-2021-reference-case-09-11-21-v6.pdf>.

<sup>87</sup> EGUs with idled SCR or SNCR in the Baseline run represent a small percentage (less than 10 percent) of the EGU fleet that is equipped with NO<sub>x</sub> post-combustion controls.

<sup>88</sup> For details on the derivation of this standard, please see preamble Section VI.B.1.

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(optimizing partially operating SCR controls or turning on idled SCR controls) are achievable in 2023 and have a uniform control cost of \$900 per ton (2016\$) for coal units that partially operate their controls and \$1,600 per ton (2016\$) for coal units that have idled their controls, and \$900 per ton (2016\$) for the other identified sources. As explained below in Section 4.3.3, the costs associated with this measure are accounted for outside of the model, and no further adjustments were made inside the model to the variable and fixed operating cost of these units or to their modeled heat rates. Under the proposed rule, 261 units are projected to fully run existing SCR controls in 2023 and in each year thereafter until the year the unit retires or at the end of the model period.

The EPA considers a unit to have optimized use of an SNCR if NO<sub>x</sub> emissions rates are equal to or less than the mode 2 rate from the NEEDS database (Summer 2021). As described in Chapter 3 of the EPA's power sector IPM Modeling Documentation, these backstop NO<sub>x</sub> mode rates are calculated from historical data and reflect operation of existing post-combustion controls. Mode 2 for SNCR-controlled coal units is intended to reflect the operation of that unit's post-combustion control based on prior years when that unit operated its control. Hence any units with existing SNCRs with NO<sub>x</sub> emission rates greater than their mode 2 rates in the 22-state region had their rates lowered to their mode 2 rates. These control options are achievable in 2023 and have a uniform control cost of \$1,800 per ton (2016\$). As explained below in Section 4.3.3, the costs associated with this measure are accounted for outside of the model, and no further adjustments were made inside the model to the variable and fixed operating cost of these units. Under this rule, 44 units are projected to fully run existing SNCR controls in 2023 and in each year thereafter until the year the unit retires or at the end of the model period.

Finally, unit combustion control configurations listed in NEEDS were compared against Table 3-14 in the documentation for the EPA Power Sector Modeling Platform v.6.20 Summer 2021 Reference Case, which lists state-of-the-art combustion control configurations based on unit firing type. This allowed the EPA to identify units that would receive state-of-the-art combustion control upgrades in IPM. The EPA then followed the procedure in the EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD to calculate each of these unit's new NO<sub>x</sub> emission rate. These upgrades were assumed to occur in the 2023 run year (though the rule does not reflect them until 2024) and have a uniform control cost of \$1,600 per ton (2016\$). As explained below



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in Section 4.3.3, the costs associated with this measure are accounted for outside of the model, and no further adjustments were made inside the model to the variable and fixed operating cost of these units. Under this rule, nine units are projected to install state-of-the-art combustion controls in 2023 and operate them in each year thereafter until the year the unit retires or at the end of the model period. The book-life of the new combustion controls is assumed to be 15 years, hence the stream of costs from 2023-45 fully captures the cost of any incremental controls under the rule. The EGU NO<sub>x</sub> mitigation strategies that are assumed to operate or are available to reduce NO<sub>x</sub> in response to each of the regulatory control alternatives are shown in Table 4-2 above; more information about the estimated costs of these controls can be found in the EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD.

Under the final rule 8 GW of SCR installations are projected. Under the more stringent alternative 15 GW of SCR installations are projected. Under the less stringent alternative 8 GW of new SCR installations are projected. The book-life of the new SCRs is assumed to be 15 years, hence the stream of costs from 2023-45 fully captures the cost of any incremental controls under the rule. Under the final rule and less stringent alternative an incremental 13 GW of coal (63 units) retirements are projected by 2030. Under the more stringent alternative 8 GW of coal retirements are projected by 2030. The associated costs of retirement are fully captured within the total costs of this rule presented in the RIA.

In addition to the limitation on ozone season NO<sub>x</sub> emissions required by the EGU emissions budgets for the 22 states and the backstop emission rate, there are four important features of the allowance trading program represented in the model that may influence the level and location of NO<sub>x</sub> emissions from affected EGUs, including: the ability of affected EGUs to buy and sell NO<sub>x</sub> ozone season allowances from one another for compliance purposes; the ability of affected EGUs to bank NO<sub>x</sub> ozone season allowances for future use; the effect of limits on the total ozone season NO<sub>x</sub> emissions from affected EGUs in each state required by the assurance provisions; and the treatment of banked pre-2023 vintage NO<sub>x</sub> ozone season allowances issued under the Revised CSAPR Update now being revised under this rule. Each of these features of the ozone season allowance trading program is described below. The analysis does not explicitly capture the dynamic budget adjustments over time, but the forced operation of

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controls during the ozone season over the forecast period (even in the absence of binding mass limits) approximates this feature of the program design.

Affected EGUs are expected to choose the least-cost method of complying with the requirements of the allowance trading program, and the distribution of ozone season NO<sub>x</sub> emissions across affected EGUs is generally governed by this cost-minimizing behavior in the analysis. The total ozone season NO<sub>x</sub> emissions from affected EGUs in this analysis are limited to the amount allowed by the sum of the NO<sub>x</sub> budgets across the 22 states, the starting bank of allowances, and any additional allowances that are banked for future use. The number of banked allowances is influenced by the determination of whether (i) existing controls that are idle in the baseline run are turned on, (ii) it is less costly to abate ozone season NO<sub>x</sub> emissions in a current ozone season than to abate emissions in a later ozone season, and (iii) the restriction on the total size of the bank, which is 21 percent of the sum of the state emissions budgets for the current control period until 2030 (at which point it declines to 10.5%). Affected EGUs are expected to bank NO<sub>x</sub> ozone season allowances in the 2023 ozone season for use in a later ozone season. The model starts with an assumed bank level in 2023 (described below) and endogenously determines the bank in each subsequent year.

The rule allows pre-2023 vintage NO<sub>x</sub> ozone season allowances to be used for compliance with this rule. The sources that would be participants in a revised Group 3 Trading Program under this rule are transitioning from several different starting points – with some sources already in the Group 3 Trading Program under its current regulations, some sources coming from the Group 2 Trading Program, and some sources not currently participating in any seasonal NO<sub>x</sub> trading program. As described in Section VI.B.12 of the preamble, the EPA is transitioning provisions that differ across the sets of potentially affected sources based on the sources' different starting points. Based on the EPA's expectation of the size of the NO<sub>x</sub> allowance bank after the one-time conversion carried out pursuant to the terms of this rule, the treatment of these banked allowances is represented in the modeling as an additional 43,389 tons of NO<sub>x</sub> allowances, the equivalent of one year of the variability limit associated with the emission budgets, that may be used by affected EGUs during the 2023 ozone season or in later ozone seasons under the Transport FIP for the 2015 ozone NAAQS and the more and less stringent alternatives.

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While there are no explicit limits on the exchange of allowances between affected EGUs and on the banking of 2023 and future-year vintage NO<sub>x</sub> ozone season allowances, the assurance provisions limit the amount of seasonal NO<sub>x</sub> emissions by affected EGUs in each of the 22 states. The assurance level limits affected EGU emissions over an ozone season to the state's NO<sub>x</sub> ozone season emissions budget plus an increment equal to 21 percent of each state's emissions budget. This increment is called the variability limit. See Section VI.B.5 of the preamble for a discussion of the purpose of the assurance provision and further detail about how the variability limits and assurance levels are determined. If a state exceeds its assurance level in a given year, sources within that state are assessed a 3-to-1 allowance surrender penalty on the excess tons. Section VI.B.5 of the preamble also explains how the EPA then determines which EGUs are subject to this surrender requirement. In the modeling, the assurance provisions are represented by a limit on the total ozone season NO<sub>x</sub> emissions that may be emitted by affected EGUs in each state, and thus the modeling does not permit affected EGUs to collectively emit beyond their respective state's assurance levels and thus incur penalties.

#### *4.3.3 Methodology for Estimating Compliance Costs*

This section describes the EPA's approach to quantify estimated compliance costs in the power sector associated with the three illustrative regulatory control alternatives. These compliance costs include estimates projected directly by the model as well as calculations performed outside of the model that use IPM model inputs and methods. The model projections capture the costs associated with shifting generation to lower-NO<sub>x</sub> emitting EGUs. As discussed in the previous subsection, the costs of increasing the use and optimizing the performance of existing and operating SCRs and SNCRs,<sup>89</sup> and for installing or upgrading NO<sub>x</sub> combustion controls, were estimated outside of the model. The costs for these three NO<sub>x</sub> mitigation strategies are calculated based on IPM emissions projections and use the same NO<sub>x</sub> control cost equations used in IPM. Therefore, this estimate is consistent with modeled projections and provides the best available quantification of the costs of these NO<sub>x</sub> mitigation strategies.

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<sup>89</sup> This includes optimizing the performance of SCRs that were not operating.

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The following steps summarize the EPA’s methodology for estimating the component of compliance costs that are calculated outside of the model for the final rule alternative in 2023. Similar calculations are performed for every year in the forecast horizon<sup>90</sup>:

(1) In the model projections, identify all EGUs in the 22 states that can adopt the following NO<sub>x</sub> mitigation strategies (described in previous subsection):

- Fully operating existing SCRs
- Fully operating existing SNCRs
- Installing state-of-the-art combustion controls

(2) Estimate the total NO<sub>x</sub> reductions that are attributable to each of these strategies:

- Fully operating existing SCRs at coal steam, oil/gas steam, combined cycle, and combustion turbine units: 5,314 tons
- Fully operating existing SNCRs: 1,192 tons
- Installing state-of-the-art combustion controls: 6,288 tons

(3) Estimate the average cost (in 2016\$) associated with each of these strategies:<sup>91</sup>

- Fully operating existing SCRs at coal steam units, oil/gas steam, combined cycle, and combustion turbine units: \$900/ton
- Fully operating existing SNCRs: \$1,800/ton
- Installing state-of-the-art combustion controls: \$1,600/ton

(4) Multiply (2) by (3) to estimate the total cost associated with each of these strategies.

Table 4-5 summarizes the results of this methodology for the final rule alternative in 2023.

**Table 4-5. Summary of Methodology for Calculating Compliance Costs Estimated Outside of IPM for the Transport FIP for the 2015 Ozone NAAQS, 2023 (2016\$)**

NO <sub>x</sub> Mitigation Strategy	NO <sub>x</sub> Ozone Season Emissions (tons)	Average Cost (\$/ton)	Total Cost (\$MM)
Optimize existing SCRs at coal steam, oil/gas, combined cycle, and combustion turbine units	5,341	900	5
Optimize existing SNCRs	1,192	1,800	2

<sup>90</sup> For more information on the derivation of costs and useful life of combustion controls, please see EGU NO<sub>x</sub> Mitigation Strategies Final Rule TSD.

<sup>91</sup> See EGU NO<sub>x</sub> Mitigation Strategies Proposed Rule TSD for derivation of cost-per-ton estimates for fully operating SCRs and upgrading to state-of-the-art combustion controls.

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Installing state- of-the-art combustion controls	2,251	1,600	4
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The EPA exogenously updated the emissions rates for the identified EGUs within the 22 states consistent with the set of controls determined for 2023-2025 within IPM. The model was updated to incorporate the emissions budgets identified for each case, and the first-year bank adjustment as outlined in Section 4.3.2. The backstop emission rate was also imposed on affected uncontrolled units as outlined in Table 4-2, either in 2025 (in the more stringent alternative) or in 2030 (in the final rule and less stringent alternatives), which forced units to choose to either retrofit or retire in either of those years, respectively.

The change in the reported power system production cost between the rule alternative model run and the baseline run was used to capture the cost of generation shifting and the cost of new SCR installations. The total costs of compliance with the regulatory control alternatives are estimated as the sum of the costs that are modeled within IPM and the costs that are calculated outside the model.

#### 4.4 Estimating Emissions Units, Emissions Reductions, and Costs for Non-EGUs

For non-EGUs, the EPA developed an analytical framework to facilitate decisions about industries and emission unit types for inclusion 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 emission unit types included in the proposed FIP.<sup>92</sup> To further evaluate the industries and emissions unit types identified and to establish the 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 state implementation plan (SIP) submittals, consent decrees, and permit limits. That evaluation is detailed in the *Non-EGU Sectors Technical Support Document (TSD)* prepared for the proposed FIP.<sup>93</sup> The EPA is retaining the industries and many of the

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<sup>92</sup> The memorandum is available in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150>.

<sup>93</sup> The TSD is available in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145>.

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emissions unit types included in the proposal in this final action. Below is a summary of the adjustments and additions to the emissions requirements and limitations the EPA made between the proposed FIP and this final rule.

- For Pipeline Transportation of Natural Gas, the EPA is finalizing the same emissions limits as proposed; however, the EPA is adjusting the applicability criteria to exclude emergency engines. Further, to allow for the industry to install controls on the engines with the largest potential for emissions reductions at cost-effective thresholds, the final regulations allow for the use of facility-wide emissions averaging for engines in the industry.
- For Cement and Concrete Product Manufacturing, in the final rule the EPA has removed the daily source cap limit, which could have resulted in an artificially restrictive NO<sub>x</sub> emissions limit for affected cement kilns due to lower operating periods resulting from the COVID-19 pandemic.
- For Iron and Steel and Ferroalloy Manufacturing, the EPA is only finalizing a test-and-set requirement for reheat furnaces premised on the installation of low-NO<sub>x</sub> burners. By not finalizing the other proposed emissions limits that were likely to require the installation of SCR, the EPA has addressed the various concerns regarding the feasibility and cost-effectiveness of installation of the other proposed controls at other unit types 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 Iron and Steel and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills, the EPA is finalizing a low-use exemption to eliminate the need to install controls on low-use boilers that would have resulted in relatively small reductions.
- For municipal waste combustors in Solid Waste Combustors and Incinerators, the EPA is finalizing emissions limits, summarized in Table 4-1.

In the final rule, the EPA is requiring that controls be installed and operational by 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. Where an individual source submits a

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satisfactory demonstration that an extension of time to comply beyond 2026 is necessary, the EPA may grant an extension of up to one year for that source to fully implement the controls, after which the source may request and the EPA may grant an additional extension of up to two additional years for full compliance, where specific criteria are met. The EPA's evaluation of timing issues associated with this rule are further discussed in Section VI.A of the preamble. Because it is not possible to currently know which sources or how many may seek or be granted an extension of time to comply with the emissions limits, we assume in the RIA that all covered non-EGUs comply with the rule beginning in 2026.

With the exception of Solid Waste Combustors and Incinerators for each industry and emissions unit type, using a 2019 inventory prepared from the emissions inventory system (EIS) the EPA first estimated 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 for MWCs using the 2019 inventory and the NEEDS-v6-summer-2021-reference-case workbook.<sup>94</sup> 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.

Using the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits (see Table 4-18 below), and information on control efficiencies and default cost/ton values from the CMDDB<sup>95</sup>, the EPA estimated NO<sub>x</sub> emissions reductions and costs for the year 2026. For the final rule the EPA did not run the Control Strategy Tool (CoST) to estimate emissions reductions and costs and programmed the assessment using R.<sup>96</sup> The EPA did not estimate emissions reductions of SO<sub>2</sub>, PM<sub>2.5</sub>, CO<sub>2</sub> and other pollutants that may be associated with controls on non-EGU emissions units. 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 CMDDB. We modified SCC codes

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<sup>94</sup> Available here: <https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6>.

<sup>95</sup> More information about the Control Strategy Tool (CoST) and the control measures database (CMDDB) can be found at the following link: <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution>.

<sup>96</sup> R is a free software environment for statistical computing and graphics. Additional information is available here: <https://www.r-project.org/>. The R code that processed the data to estimate the emissions reductions and costs is available upon request.

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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.<sup>97</sup>

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 be different than those estimated in this assessment; the estimated emissions reductions from and costs to meet the final rule emissions limits may be different than those estimated in this assessment. The reported total costs do not include the costs of monitoring, recordkeeping, reporting, or testing ~~costs~~. The EPA submitted an information collection request (ICR) to OMB associated with the monitoring, calibrating, recordkeeping, reporting, and testing activities required for non-EGU emissions units -- ICR for the Final Rule, Federal Good Neighbor 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 X.B.2 of the final rule preamble. The EPA estimates monitoring, recordkeeping, reporting, and testing costs of approximately \$3.8 million per year on average for the first three years. These costs are not reflected in the cost estimates in **Error! Reference source not found.** and Table 4-20 below.<sup>98</sup>

#### 4.5 Estimated Impacts of the Regulatory Control Alternatives

##### 4.5.1 Emissions Reduction Assessment for EGUs

As indicated in Chapter 1, the EGU NO<sub>x</sub> emissions reductions are presented in this RIA from 2023 through 2042 and are based on IPM projections. As outlined in Section 4.3.2 IPM is

<sup>97</sup> <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668>

<sup>98</sup> ~~The EPA submitted an information collection request (ICR) to OMB associated with the monitoring, calibrating, recordkeeping, reporting and testing activities required for non-EGU emissions units -- ICR for the Final Rule, Federal Good Neighbor 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 X.B.2 of the final rule preamble. The ICR includes estimated monitoring, recordkeeping, reporting, and testing costs of approximately \$3.78 million per year on average for the first three years. These costs are not reflected in the cost estimates in Table 4-19 and Table 4-20 below.~~

**Commented [Round 343]:** 3/13: much of the footnote language should be brought to the text. EPA is welcome to keep the remaining footnote text or strike redundant areas.

**Commented [EPA44R43]:** Thank you for the suggestion.

We added the footnote language into the suggested edit for completeness and deleted the footnote.



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operating existing and newly installed controls seasonally based on historical operation patterns and seasonal and annual emission constraints within the model. Table 4-6 presents the estimated reduction in power sector NO<sub>x</sub> emissions resulting from compliance with the evaluated regulatory control alternatives (i.e., emissions budgets) in the 22 states, as well as the impact on other states. The emission reductions follow an expected pattern: the less stringent alternative produces smaller emissions reductions than the final rule emissions budgets, and the more stringent alternative results in more NO<sub>x</sub> emissions reductions.

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**Table 4-6. EGU Ozone Season NO<sub>x</sub> Emissions and Emissions Changes (thousand tons) for the Baseline run and the Regulatory Control Alternatives from 2023 - 2045<sup>99</sup>**

Ozone Season NO <sub>x</sub>		Total Emissions			Change from Baseline run			
(Thousand tons)	Baseline run	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	
2023	22 States	230	220	220	220	-10	-10	-10
	Other States	143	143	143	143	0	0	0
	Nationwide	373	363	363	363	-10	-10	-10
2024	22 States	203	181	193	168	-22	-10	-35
	Other States	128	129	128	130	1	0	2
	Nationwide	331	310	321	298	-21	-10	-33
2025	22 States	176	143	167	116	-34	-9	-60
	Other States	113	115	113	117	2	0	4
	Nationwide	289	258	279	233	-32	-10	-56
2026	22 States	167	140	159	114	-27	-8	-53
	Other States	107	109	107	110	2	0	3
	Nationwide	274	248	266	224	-25	-8	-49
2027	22 States	157	137	151	111	-20	-6	-46
	Other States	101	103	101	104	2	0	3
	Nationwide	258	239	252	215	-19	-6	-43
2028	22 States	147	134	143	109	-14	-4	-39
	Other States	95	96	95	97	2	0	3
	Nationwide	242	230	238	206	-12	-4	-36
2030	22 States	137	101	102	103	-36	-35	-33
	Other States	91	93	94	94	2	3	3
	Nationwide	228	194	195	197	-34	-33	-31
2035	22 States	132	101	101	103	-30	-30	-29
	Other States	88	89	89	90	1	1	2
	Nationwide	220	190	190	193	-29	-30	-27
2040	22 States	119	89	89	91	-30	-30	-29
	Other States	79	79	79	79	0	0	0
	Nationwide	198	169	168	170	-30	-30	-29
2045	22 States	102	80	80	80	-22	-22	-22
	Other States	76	76	76	76	0	0	0
	Nationwide	178	156	156	156	-22	-22	-22

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Within the compliance modeling, in addition to compliance with the mass budgets, emissions reductions are also driven by the assumption that units fully operate their controls during the ozone season. For units with existing controls, this is reflected in the achievement of the “widely achievable” rate as outlined in Section 4.3.2. For units that lack existing SCR controls, this is reflected in the decision to install new controls (which must be operated in the ozone season) or retire. The final rule and more stringent alternative feature identical Engineering Analysis derived budgets based on installation of SCRs in the 2025 run year in the 19-state region. However, the final rule alternative defers the backstop emission rate until the 2030 run year for units without SCRs, while the more stringent alternative assumes the backstop emission rate is imposed in the 2025 run year. The less stringent alternative imposes Engineering Analysis derived budgets based on installation of SCRs in the 2030 run year in the 19-state region, and the backstop emission rate taking effect in the 2030 run year.

Hence emission reductions are lower under the less stringent alternative compared to the final rule through 2030 (since the mass budget is less stringent). The more stringent alternative features the backstop emission rate in effect in the 2025 run year, for which the model is set up to constrain affected EGUs to retrofit or retire in the 2025 run year, driving higher abatement (and more SCR retrofits) than the final rule before 2030. However, in 2030, the modeling of the final rule and less stringent alternatives estimates more retirements relative to the more stringent alternative. The more stringent alternative extends the operating life of plants that chose to retrofit in 2025 rather than retire and therefore, in 2030 onwards, emissions reductions for the final rule and less stringent alternative are slightly greater, since budgets are the same and the backstop emission rate is also in effect in both scenarios. For details on the EGU emissions controls assumed in each of the regulatory control alternatives, please see Table 4-2.

The results of the EPA’s analysis show that, with respect to compliance with the EGU NO<sub>x</sub> emission budgets in 2023, maximizing the use of existing operating SCRs provides the largest amount of ozone season NO<sub>x</sub> emission reductions (54 percent, affecting 261 units), installing state-of-the-art combustion controls provides the next highest levels of ozone season reductions (22 percent, affecting 9 units), while optimizing existing SNCRs (12 percent, affecting 44 units) and generation shifting (11 percent) make up the remaining ozone season NO<sub>x</sub> reductions. (Although the budgets are not set using generation shifting, the IPM modeling

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for the RIA allows generation shifting as a compliance strategy and thus some reductions associated with generation shifting are observed in this analysis.) Based on this analysis of how EGUs are expected to comply with the Transport FIP for the 2015 ozone NAAQS, none of the Group 3 states are projected to exceed their variability limits, nor use a substantial number of allowances from the starting bank during the 2023-2042 period.<sup>100</sup>

In addition to the ozone season NO<sub>x</sub> reductions, there will also be reductions of other air emissions associated with EGUs burning fossil fuels (i.e., co-pollutants) that result from compliance strategies to reduce seasonal NO<sub>x</sub> emissions. These other emissions include the annual total changes in emissions of NO<sub>x</sub>, SO<sub>2</sub>, CO<sub>2</sub>, and direct PM<sub>2.5</sub> emissions changes. The emissions reductions are presented in Table 4-7.

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<sup>100</sup> As shown in **Error! Reference source not found.** in 2023 and 2025 seasonal NO<sub>x</sub> emissions from affected EGUs in the Group 3 states are projected to emit at levels equal to or below the aggregated state budgets, and therefore (i) will not bank additional allowances, or (ii) on net, not use any banked allowances available at the end of the previous year or, in the case of 2023, from the starting bank.

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**Table 4-7. EGU Annual Emissions and Emissions Changes for NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, and CO<sub>2</sub> for the Regulatory Control Alternatives for 2023-2045**

Annual NO <sub>x</sub>		Total Emissions			Change from Baseline run			
(thousand tons)	Baseline run	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	
2023	22 States	561	546	546	546	-15	-15	-15
	Other States	328	329	329	329	0	0	0
	Nationwide	889	874	875	874	-15	-15	-15
2024	22 States	491	464	476	429	-26	-15	-62
	Other States	286	287	286	291	1	0	5
	Nationwide	777	752	762	720	-25	-15	-57
2025	22 States	420	383	406	312	-38	-14	-108
	Other States	244	246	243	253	2	-1	9
	Nationwide	664	629	649	566	-35	-15	-99
2026	22 States	398	367	386	301	-31	-12	-96
	Other States	232	234	231	240	2	-1	8
	Nationwide	630	601	617	541	-29	-12	-88
2027	22 States	375	351	366	290	-24	-9	-85
	Other States	220	222	220	227	2	0	7
	Nationwide	595	573	586	517	-22	-9	-78
2028	22 States	353	336	346	279	-17	-7	-73
	Other States	208	210	209	214	1	0	5
	Nationwide	561	545	554	493	-16	-7	-68
2030	22 States	324	261	262	270	-64	-62	-54
	Other States	208	210	211	212	1	3	4
	Nationwide	533	471	473	482	-62	-59	-50
2035	22 States	304	254	254	259	-49	-49	-44
	Other States	197	201	201	201	3	3	4
	Nationwide	501	455	455	460	-46	-46	-41
2040	22 States	267	221	221	225	-46	-46	-41
	Other States	173	174	174	174	1	1	1
	Nationwide	440	395	395	400	-45	-45	-40
2045	22 States	218	195	195	197	-23	-23	-22
	Other States	160	160	160	160	0	1	0
	Nationwide	378	355	356	357	-23	-22	-21

**Commented [EO 1286645]:** The emission reductions in the outer years for the most stringent option for EGUs is rather low compared to other options. Would EPA explain why this is the case and provide such a discussion in the RIA?

**Commented [EPA46R45]:** The more stringent scenario assumes imposition of the backstop emission rate in the 2025 run year rather than the 2030 run year. This in turn results in additional SCR installation relative to the Final rule (which instead sees higher retirements in 2030). Under the Final rule, capacity that retires in 2030 is replaced with lower emitting technology. As a result, emissions are higher under the more stringent scenario in later years.

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Annual SO <sub>2</sub>		Total Emissions				Change from Baseline run		
(thousand tons)		Baseline run	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	Final Rule	Less-Stringent Alternative	More-Stringent Alternative
2023	22 States	916	915	913	915	-1	-3	-1
	Other States	279	279	279	279	0	0	0
	Nationwide	1195	1194	1192	1194	-1	-3	-1
2024	22 States	787	766	782	723	-21	-5	-64
	Other States	239	240	239	243	1	0	4
	Nationwide	1025	1006	1021	966	-19	-5	-59
2025	22 States	657	617	651	531	-40	-6	-127
	Other States	199	201	198	207	2	-1	8
	Nationwide	856	818	849	738	-38	-7	-118
2026	22 States	574	543	569	463	-31	-5	-111
	Other States	181	183	181	188	2	0	7
	Nationwide	755	726	750	651	-29	-5	-104
2027	22 States	491	469	487	395	-22	-4	-96
	Other States	163	164	163	168	1	0	5
	Nationwide	654	633	650	563	-21	-4	-91
2028	22 States	408	395	405	327	-13	-3	-80
	Other States	145	145	146	149	0	0	4
	Nationwide	553	540	551	476	-13	-2	-77
2030	22 States	385	289	283	330	-95	-102	-54
	Other States	147	150	151	151	2	4	3
	Nationwide	532	439	434	481	-93	-98	-51
2035	22 States	366	342	344	349	-24	-22	-16
	Other States	135	138	138	137	3	3	2
	Nationwide	501	480	482	486	-21	-19	-15
2040	22 States	305	279	279	294	-26	-26	-12
	Other States	126	127	127	127	1	1	1
	Nationwide	432	406	406	420	-25	-25	-11
2045	22 States	220	206	206	214	-15	-14	-6
	Other States	128	128	128	128	0	0	0
	Nationwide	349	334	334	342	-15	-15	-7

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Annual PM <sub>2.5</sub>		Total Emissions				Change from Baseline run		
(thousand tons)		Baseline run	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	Final Rule	Less-Stringent Alternative	More-Stringent Alternative
2023	22 States	63	63	63	63	0	0	0
	Other States	40	40	40	40	0	0	0
	Nationwide	103	103	103	103	0	0	0
2024	22 States	57	56	56	55	-1	0	-2
	Other States	36	36	36	37	0	0	1
	Nationwide	93	92	93	92	-1	0	-1
2025	22 States	51	49	50	47	-2	-1	-3
	Other States	33	33	33	34	0	0	1
	Nationwide	84	82	83	81	-2	-1	-2
2026	22 States	49	48	49	46	-1	0	-3
	Other States	33	33	33	34	0	0	1
	Nationwide	82	81	81	80	-1	0	-2
2027	22 States	48	47	48	46	-1	0	-2
	Other States	32	32	32	33	0	0	1
	Nationwide	80	80	80	79	-1	0	-2
2028	22 States	47	46	47	45	0	0	-2
	Other States	32	32	32	33	0	0	1
	Nationwide	79	78	79	77	0	0	-1
2030	22 States	45	43	43	44	-2	-2	0
	Other States	32	32	32	32	0	0	0
	Nationwide	76	75	75	76	-1	-1	0
2035	22 States	46	44	44	45	-2	-2	-1
	Other States	30	30	30	30	0	0	0
	Nationwide	75	74	74	75	-1	-1	0
2040	22 States	44	43	43	44	-2	-2	0
	Other States	28	28	28	28	0	0	0
	Nationwide	73	71	71	72	-2	-2	0
2045	22 States	42	42	42	42	0	0	0
	Other States	28	28	28	28	0	0	0
	Nationwide	70	70	70	70	0	0	0

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Annual CO <sub>2</sub>		Total Emissions				Change from Baseline run		
(million short tons)	Baseline run	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	
2023	22 States	1033	1032	1032	1032	0	0	0
	Other States	591	592	592	591	0	0	0
	Nationwide	1624	1624	1624	1624	0	0	0
2024	22 States	947	935	943	919	-12	-4	-28
	Other States	539	541	540	548	2	0	8
	Nationwide	1487	1476	1483	1467	-10	-4	-20
2025	22 States	862	838	854	806	-24	-8	-56
	Other States	488	491	488	504	3	0	17
	Nationwide	1350	1329	1342	1310	-21	-8	-40
2026	22 States	844	826	839	796	-18	-6	-48
	Other States	477	480	477	492	3	0	15
	Nationwide	1322	1306	1316	1288	-16	-6	-34
2027	22 States	827	814	823	786	-13	-3	-41
	Other States	467	469	467	480	2	0	13
	Nationwide	1294	1284	1290	1266	-10	-3	-28
2028	22 States	809	803	808	776	-7	-1	-33
	Other States	457	459	457	468	2	0	12
	Nationwide	1266	1261	1265	1244	-5	-1	-22
2030	22 States	784	753	755	769	-31	-29	-16
	Other States	450	455	456	458	5	6	7
	Nationwide	1235	1209	1211	1227	-26	-23	-8
2035	22 States	792	774	774	781	-19	-18	-12
	Other States	436	438	438	439	2	3	3
	Nationwide	1228	1212	1213	1220	-16	-15	-8
2040	22 States	727	706	706	716	-21	-21	-11
	Other States	411	411	412	412	1	1	1
	Nationwide	1138	1117	1117	1128	-20	-20	-10
2045	22 States	670	662	662	666	-9	-9	-4
	Other States	400	400	400	400	0	0	0
	Nationwide	1070	1061	1062	1066	-9	-8	-4



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4.5.2 Compliance Cost Assessment for EGUs

The estimates of the changes in the cost of supplying electricity for the regulatory control alternatives are presented in Table 4-8.<sup>101</sup> Since the final rule does not result in any additional recordkeeping, monitoring or reporting requirements, the costs associated with compliance, monitoring, recordkeeping, and reporting requirements are not included within the estimates in this table.

**Table 4-8. National Power Sector Compliance Cost Estimates (millions of 2016\$) for the Regulatory Control Alternatives**

	Final Rule	More-Stringent Alternative	Less-Stringent Alternative
2023-2027 (Annualized)	14	677	-19
2023-2045 (Annualized)	449	645	446
2023 (Annual)	57	49	56
2024 (Annual)	-5	835	-35
2025 (Annual)	-5	835	-35
2026 (Annual)	-5	835	-35
2027 (Annual)	24	762	-47
2030 (Annual)	705	835	772
2035 (Annual)	817	592	847
2045 (Annual)	182	251	168

“2023-2027 (Annualized)” reflects total estimated annual compliance costs levelized over the period 2023 through 2027 and discounted using a 3.76 real discount rate.<sup>102</sup> This does not include compliance costs beyond 2027. “2023-2045 (Annualized)” reflects total estimated annual compliance costs levelized over the period 2023 through 2045 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2045. “2023 (Annual)” through “2045 (Annual)” costs reflect annual estimates in each of those years.<sup>103</sup>

There are several notable aspects of the results presented in Table 4-8. One notable result is that the estimated annual compliance costs for the final rule and less stringent alternative are negative (i.e., a cost reduction) in 2023 through 2026, although this regulatory control alternative reduces NO<sub>x</sub> emissions by 40 thousand tons as shown in Table 4-6. While seemingly

<sup>101</sup> Reported yearly costs reflect costs incurred in IPM run year mapped to respective calendar year. For details, please see Chapter 2 of the IPM documentation.

<sup>102</sup> This table reports compliance costs consistent with expected electricity sector economic conditions. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM’s objective function for cost-minimization. The NPV of costs was then used to calculate the levelized annual value over a 5-year period (2023-2027) and a 23-year period (2023-2045) using the 3.76% rate as well. Tables ES-15 and 8-7 report the NPV of the annual stream of costs from 2023-2042 using 3% and 7% consistent with OMB guidance.

<sup>103</sup> Cost estimates include financing charges on capital expenditures that would reflect a transfer and would not typically be considered part of total social costs.

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counterintuitive, estimating negative compliance costs in a single year is possible given the assumption of perfect foresight. 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.<sup>104</sup> The specific reason for why costs are negative in these years for these two alternatives follows.

Under the final rule and more stringent alternative budgets assume SCR/SNCR optimization, state-of-the-art combustion control and SCR installations are selected by the 2025 run year. Under the less stringent alternative, budgets assume SCR/SNCR optimization, state-of-the-art combustion control by the 2025 run year, but SCR installation is not assumed until the 2030 run year. Under the final rule and the less stringent alternative, the backstop emission rate is imposed in the 2030 run year, while under the more stringent alternative, the backstop emission rate is imposed in the 2025 run year. In the case of the final rule and less stringent alternative, we see two waves of incremental coal retirement relative to the baseline – roughly 2 GW are retired in the 2025 run year (responding to tightening budgets), and an incremental 12 GW of retirements in the 2030 run year (responding to the backstop emission rate). In the case of the more stringent alternative, we see a single wave of an incremental 12 GW relative to the baseline in 2025.

The first wave of coal retirements reflects units that face challenging near-term conditions in the baseline but would have been more economically valuable later in the baseline forecast period, when demand growth and other firm retirements would improve their competitive position. Hence early retirement of this capacity in the final rule and less stringent alternative results in slightly lower near-term costs, but higher longer-term costs, and a point estimate of negative costs in a single year.<sup>105</sup> In the 2030 run year, the imposition of the backstop emission rate under the final rule and the less stringent alternative results in a greater amount of coal retirement reflective of projected economic preferences of unit owners/operators searching for least-cost compliance strategies. Under the more stringent alternative, the backstop emission rate

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<sup>104</sup> For more information, please see Chapter 2 of the IPM documentation.

<sup>105</sup> 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 this RIA.

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is imposed in 2025, which results in a single wave of coal retirements and higher costs throughout the forecast period.

Under the final rule, operating existing SCR and SNCR controls and upgrading to state-of-the-art combustion controls provides a large share of the total emissions reductions in 2023. The model is constrained in 2023 to builds and retrofits that occurred in the baseline and features higher natural gas and coal prices reflecting near term trends. This means there is less flexibility to respond to the mass budgets, and costs are higher in 2023 than in 2025 and 2028, when fuel prices return to fundamentals and builds are not constrained to baseline levels. The imposition of the deferred backstop emission rate in 2030 results in retrofit/retirement decisions being made in that year as least-cost compliance strategies and fleet turnover as a result. Hence costs rise in 2030, and projected costs for the final rule peak in 2035 at \$817 million (2016\$) and annualized costs for the 2023-2045 period are \$449 million (2016\$). To put these costs into context, the incremental 2035 projected cost constitutes 0.6 percent of total projected baseline system production costs.

Under the more stringent alternative, while budgets are unchanged from the final rule, the backstop emission rate is imposed in the 2025 run year. In the model, affected units are required to retrofit/retire sooner, and costs peak in 2025 at \$835 million as a result. The annualized costs over the 2023-2045 period are \$645 million.

Under the less stringent alternative, the backstop emission rate is imposed in the 2030 run year consistent with the final rule, but mass budgets in the 2025 and 2028 run years are less stringent since they are based on Engineering Analysis that does not assume installation of new SCRs. Hence costs are lower in the 2025 and 2028 run years, before converging to final rule levels in 2030 and beyond. Costs peak in 2035 at \$772 million as a result. The annualized costs over the 2023-2045 period are \$446 million.

In addition to evaluating annual compliance cost impacts, the EPA believes that a full understanding of these three regulatory control alternatives benefits from an evaluation of annualized costs over the 2023-2027 timeframe. Starting with the estimated annual cost time series, it is possible to estimate the net present value of that stream, and then estimate a leveled

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annual cost associated with compliance with each regulatory control alternative.<sup>106</sup> For this analysis we first calculated the NPV of the stream of costs from 2023 through 2027<sup>107</sup> using a 3.76 percent discount rate. In this cost annualization we use a 3.76 percent discount rate, which is consistent with the rate used in IPM’s objective function for minimizing the NPV of the stream of total costs of electricity generation. This discount rate is meant to capture the observed equilibrium market rate at which investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC).<sup>108</sup> After calculating the NPV of the cost streams, the same 3.76 percent discount rate and 2023-2027 time period are used to calculate the levelized annual (i.e., annualized) cost estimates shown in Table 4-8.<sup>109</sup> The same approach was used to develop the annualized cost estimates for the 2023-2045 timeframe. Additionally, note that the 2023-2027 and 2023-2045 equivalent annualized compliance cost estimates have the expected relationship to each other; the annualized costs are lowest for the less stringent alternative, and highest for the more stringent alternative.

#### 4.5.3 Impacts on Fuel Use, Prices and Generation Mix

The Transport FIP for the 2015 ozone NAAQS is expected to result in significant NO<sub>x</sub> emissions reductions. It is also expected to have some impacts to the economics of the power sector. While these impacts are relatively small in percentage terms, consideration of these potential impacts is an important component of assessing the relative impact of the regulatory control alternatives. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, capacity by fuel type, and retail electricity prices for the 2023, 2025 and 2030 IPM model run years.

Table 4-9 and Table 4-10 present the percentage changes in national coal and natural gas usage by EGUs in the 2023, 2025, and 2030 run years. These fuel use estimates reflect a modest

<sup>106</sup> The XNPV() function in Microsoft Excel 2013 was used to calculate the NPV of the variable stream of costs, and the PMT() function in Microsoft Excel 2013 is used to calculate the level annualized cost from the estimated NPV.

<sup>107</sup> Consistent with the relationship between IPM run years and calendar years, EPA assigned 2023 compliance cost estimates to both 2022 and 2023 in the calculation of NPV, and 2025 compliance cost to 2024 and 2025. For more information, see Chapter 7 of the IPM Documentation.

<sup>108</sup> The IPM Baseline run documentation (Section 10.4.1 Introduction to Discount Rate Calculations) states “The real discount rate for all expenditures (capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA Platform v6 is 3.76%.”

<sup>109</sup> The PMT() function in Microsoft Excel 2013 is used to calculate the level annualized cost from the estimated NPV.

**Commented [EO 1286647]:** Suggest more clarification is needed here to explain the following. It is unclear why the more stringent alternative results in lower retail price impacts, lower coal retirements, and higher coal generation in 2030 compared to the proposal and the less stringent alternative.

**Commented [EPA48R47]:** The more stringent scenario features the backstop emission rate earlier (RY 2025) than under the final rule (RY 2030).

Under the final rule, fewer units (8 GW) install SCR controls than under the more stringent scenario (15 GW). Under the final rule, these controls are installed in RY 2030, while under the more stringent scenario they are installed in RY 2025. Fewer retrofits under the final rule are balanced by greater retirements (units reduce dispatch to comply with tighter cap and then retire in RY 2030, rather than retrofitting in RY 2025 and remaining online past RY 2030).

This in turn results in higher costs in RY 2025 (when investments are being made under the more stringent scenario), but comparatively lower costs in RY 2030 (when investments are being made under the final rule). This in turn drives the differential impacts seen in the retail rate impacts.

**Commented [EPA49R47]:** 3/10/2023: please add text to the RIA along the lines of the explanation that EPA provides above.

**Commented [EPA50R47]:** We added a brief description to the text.

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shift to natural gas and renewables from coal in 2025 as a result of tightening budgets. In the 2025 run year, coal consumption reductions under the more stringent alternative are driven by increasing coal EGU retirements and reduced coal dispatch as a result of tightening budgets and the need to install SCR controls or retire uncontrolled units as shown in Table 4-14. To put these reductions into context, under the Baseline, power sector coal consumption is projected to decrease from 603 million tons in 2023 to 417 million tons in 2025 (15 percent annually), whereas under the final rule coal consumption is projected to decrease from 603 million tons in 2023 to 402 million tons in 2025 (17 percent annually). Between 2015 and 2020, annual coal consumption in the electric power sector fell between 8 and 19 percent annually.<sup>110</sup>

Under the more stringent alternative, the model projects a higher ratio of SCR retrofits to retirements, and the bulk of these changes occur in the 2025 run year as compared to the final rule and less stringent alternative when the majority of retirements and retrofits are projected to occur in 2030. This in turn results in higher costs in run year 2025 under the more stringent alternative, but comparatively lower costs in run year 2030. Under the less stringent alternative and final rule, cost impacts are projected to be lower in 2025 and higher in 2030. This in turn drives the differential impacts seen in the retail rate impacts.

**Table 4-9. 2023, 2025 and 2030 Projected U.S. Power Sector Coal Use for the Baseline and the Regulatory Control Alternatives**

		Million Tons				Percent Change from Baseline		
	Year	Baseline	Final Rule	Less-Stringent Alt.	More-Stringent Alt.	Final Rule	Less-Stringent Alt.	More-Stringent Alt.
Appalachia	2023	121	121	121	121	0%	0%	0%
Interior		96	96	96	96	0%	0%	0%
Waste Coal		4	4	4	4	0%	0%	0%
West		382	382	382	382	0%	0%	0%
Total		603	603	603	603	0%	0%	0%
Appalachia	2025	80	79	79	77	-2%	-2%	-4%
Interior		76	75	76	71	-1%	0%	-7%
Waste Coal		4	4	4	4	0%	0%	0%
West		257	244	254	231	-5%	-1%	-10%
Total		417	402	412	382	-4%	-1%	-8%

<sup>110</sup> US EIA Monthly Energy Review, Table 6.2, January 2022.

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Appalachia		49	47	47	48	-4%	-3%	-2%
Interior		51	49	49	52	-3%	-3%	2%
Waste Coal	2030	4	4	4	4	0%	0%	0%
West		170	154	155	160	-10%	-9%	-6%
Total		274	254	256	265	-7%	-7%	-4%

**Table 4-10. 2023, 2025 and 2030 Projected U.S. Power Sector Natural Gas Use for the Baseline and the Regulatory Control Alternatives**

Year	Trillion Cubic Feet				Percent Change from Baseline		
	Baseline	Final Rule	Less-Stringent Alt.	More-Stringent Alt.	Final Rule	Less-Stringent Alt.	More-Stringent Alt.
2023	7.7	7.7	7.7	7.7	0%	0%	0%
2025	9.2	9.4	9.3	9.6	2%	0%	4%
2030	12.2	12.4	12.4	12.4	1%	1%	1%

**Table 4-11 and**

Table 4-12 present the projected coal and natural gas prices in 2023, 2025 and 2030, as well as the percent change from the baseline run projected due to the regulatory control alternatives. These minor impacts in 2023 are consistent with the small changes in fuel use summarized above. The projected impacts in 2025 are larger in absolute value and consistent with tightening budgets.

**Table 4-11. 2023, 2025 and 2030 Projected Minemouth and Power Sector Delivered Coal Price (2016\$) for the Baseline and the Regulatory Control Alternatives**

		\$/MMBtu				Percent Change from Baseline		
		Baseline	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	Final Rule	Less-Stringent Alternative	More-Stringent Alternative
Minemouth	2023	1.6	1.6	1.6	1.6	0%	0%	0%

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Delivered		2.2	2.2	2.2	2.2	0%	0%	0%
Minemouth	2025	1.1	1.1	1.1	1.2	0%	0%	1%
Delivered		1.7	1.7	1.7	1.7	-1%	0%	-1%
Minemouth	2030	1.1	1.2	1.2	1.2	1%	1%	1%
Delivered		1.6	1.6	1.6	1.6	-2%	-2%	-1%

**Table 4-12. 2023, 2025 and 2030 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2016\$) for the Baseline and the Regulatory Control Alternatives**

		\$/MMBtu				Percent Change from Baseline		
		Baseline	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	Final Rule	Less-Stringent Alternative	More-Stringent Alternative
Henry Hub	2023	4.8	4.8	4.8	4.8	0%	0%	0%
Delivered		4.9	4.9	4.9	4.9	0%	0%	0%
Henry Hub	2025	3.4	3.4	3.4	3.4	0%	0%	0%
Delivered		3.5	3.5	3.5	3.5	0%	0%	0%
Henry Hub	2030	2.7	2.7	2.7	2.7	0%	1%	0%
Delivered		2.8	2.8	2.8	2.8	0%	1%	0%

Table 4-13 presents the projected percentage changes in the amount of electricity generation in 2023, 2025 and 2030 by fuel type. Consistent with the fuel use projections and emissions trends above, the EPA projects an overall shift from coal to gas and renewables. The projected impacts grow in 2025 reflecting the tightening budgets and are most pronounced in 2030 reflecting the imposition of the deferred backstop emission rate in the final rule.

**Table 4-13. 2023, 2025 and 2030 Projected U.S. Generation by Fuel Type for the Baseline and the Regulatory Control Alternatives**

		Generation (TWh)				Percent Change from Baseline		
		Baseline	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	Final Rule	Less-Stringent Alternative	More-Stringent Alternative
Coal	2023	1,133	1,133	1,133	1,133	0%	0%	0%

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	Year	Generation (TWh)				Percent Change from Baseline		
		Baseline	Final Rule	Less-Stringent Alternative	More-Stringent Alternative	Final Rule	Less-Stringent Alternative	More-Stringent Alternative
Natural Gas		1,090	1,090	1,090	1,090	0%	0%	0%
Nuclear		775	775	775	775	0%	0%	0%
Hydro		289	289	289	289	0%	0%	0%
Non-Hydro RE		756	756	756	756	0%	0%	0%
Oil/Gas Steam		27	27	27	27	0%	0%	0%
Other		33	33	33	33	0%	0%	0%
Grand Total		4,103	4,103	4,103	4,103	0%	0%	0%
Coal	2025	793	765	784	737	-4%	-1%	-7%
Natural Gas		1,311	1,332	1,314	1,356	2%	0%	3%
Nuclear		724	724	724	724	0%	0%	0%
Hydro		294	295	295	295	0%	0%	0%
Non-Hydro RE		995	1,002	1,000	1,006	1%	1%	1%
Oil/Gas Steam		18	18	18	19	-1%	-2%	2%
Other		32	32	32	32	0%	0%	0%
Grand Total	4,167	4,168	4,168	4,168	0%	0%	0%	
Coal	2030	523	489	492	507	-7%	-6%	-3%
Natural Gas		1,691	1,710	1,709	1,708	1%	1%	1%
Nuclear		611	614	613	603	1%	0%	-1%
Hydro		300	300	300	301	0%	0%	0%
Non-Hydro RE		1,111	1,122	1,121	1,116	1%	1%	0%
Oil/Gas Steam		22	22	22	23	0%	0%	4%
Other		32	32	32	32	0%	0%	0%
Grand Total	4,289	4,288	4,288	4,289	0%	0%	0%	

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind.

Table 4-14 presents the projected percentage changes in the amount of generating capacity in 2023, 2025 and 2030 by primary fuel type. As explained above, the baseline run was constrained to disallow endogenous retirement in 2023 to reflect near term limits. The policy scenarios were limited to add no more capacity economically than was added under the baseline in 2023 (also reflecting near term limits). These restrictions were removed in all subsequent run years. As a result, none of the regulatory control alternatives are expected to have a net impact on overall capacity by primary fuel type in 2023. By 2030 the rule is projected to result in an additional 14 GW of coal retirements nationwide relative to the baseline, reflecting utilities making least-cost decisions on how to achieve efficient compliance with the rule while



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maintaining sufficient generating capacity to ensure grid reliability.<sup>111</sup> This constitutes a reduction of 13 percent of national coal capacity, partially reflecting some earlier retirement that would otherwise have occurred later in the forecast period in the baseline. Under the baseline run, total coal retirements between 2023 and 2030 are projected to be 74 GW (or 10.6 GW annually). Under the final rule, total coal retirements between 2023 and 2030 are projected to be 89 GW (or 12.7 GW annually). This is compared to an average recent historical retirement rate of 11 GW per year from 2015 – 2020.<sup>112</sup>

Additionally, the rule is projected to incentivize an incremental 8 GW of SCR retrofit at coal plants. The rule is also projected to result in an incremental 3 GW of renewable capacity additions in 2025 (primarily consisting of solar capacity builds). These builds reflect early action, i.e., builds that would otherwise have occurred later in the forecast period. By 2035-40 total solar capacity equilibrates between the baseline and final rule alternatives.

**Commented [EO 1286651]:** Please provide the reliability assessment TSD. [This comment predates EPA's provision of the TSD, including for reference]

**Commented [EPA52R51]:** Thank you

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<sup>111</sup> For further discussion of how the rule is anticipated to integrate into the ongoing power sector transition while not impacting resource adequacy or grid reliability, see Section VI.B of the preamble, and the Reliability Assessment TSD included in the docket.

<sup>112</sup> See EIA's Today in Energy: <https://www.eia.gov/todayinenergy/detail.php?id=50838>.

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**Table 4-14. 2023, 2025 and 2030 Projected U.S. Capacity by Fuel Type for the Baseline run and the Regulatory Control Alternatives**

	Year	Capacity (GW)				Percent Change from Baseline run		
		Baseline run	Final Rule	Less-Stringent Alt	More-Stringent Alt	Final Rule	Less-Stringent Alt	More-Stringent Alt
Coal	2023	187	187	187	187	0%	0%	0%
Natural Gas		441	441	441	441	0%	0%	0%
Nuclear		97	97	97	97	0%	0%	0%
Hydro		102	102	102	102	0%	0%	0%
Non-Hydro RE		241	241	241	241	0%	0%	0%
Oil/Gas Steam		73	73	73	73	0%	0%	0%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,148	1,148	1,148	1,148	0%	0%	0%
Coal	2025	140	138	138	128	-1%	-1%	-9%
Natural Gas		436	436	436	439	0%	0%	1%
Nuclear		91	91	91	91	0%	0%	0%
Hydro		102	102	102	102	0%	0%	0%
Non-Hydro RE		301	304	303	305	1%	1%	1%
Oil/Gas Steam		60	60	60	62	0%	1%	4%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,135	1,137	1,136	1,133	0%	0%	0%
Coal	2030	112	98	98	103	-13%	-13%	-8%
Natural Gas		468	477	477	474	2%	2%	1%
Nuclear		76	76	76	75	1%	0%	-1%
Hydro		103	103	103	103	0%	0%	0%
Non-Hydro RE		339	343	342	343	1%	1%	1%
Oil/Gas Steam		62	64	64	64	2%	3%	2%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,168	1,168	1,167	1,168	0%	0%	0%

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind

The EPA estimated the change in the retail price of electricity (2016\$) using the Retail Price Model (RPM).<sup>113</sup> The RPM was developed by ICF for the EPA and uses the IPM estimates of changes in the cost of generating electricity to estimate the changes in average retail electricity prices. The prices are average prices over consumer classes (i.e., consumer, commercial, and

<sup>113</sup> See documentation available at: <https://www.epa.gov/airmarkets/retail-price-model>

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industrial) and regions, weighted by the amount of electricity used by each class and in each region. The RPM combines the IPM annual cost estimates in each of the 64 IPM regions with EIA electricity market data for each of the 25 electricity supply regions in the electricity market module of the National Energy Modeling System (NEMS).<sup>114</sup>

**Table 4-15,**

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<sup>114</sup> See documentation available at:  
[https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/m068\(2020\).pdf](https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/m068(2020).pdf)

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Table 4-16, and Table 4-17 present the projected percentage changes in the retail price of electricity for the three regulatory control alternatives in 2023, 2025 and 2030, respectively. Consistent with other projected impacts presented above, average retail electricity prices at both the national and regional level are projected to be small in 2023. In 2025, the EPA estimates that this rule will result in a less than 0.2 percent increase in national average retail electricity price, or by about 0.19 mills/kWh. In 2030, the EPA estimates that this rule will result in a 0.9% increase in national average retail electricity price, or by about 0.80 mills/KWh.

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**Table 4-15. Average Retail Electricity Price by Region for the Baseline and the Regulatory Control Alternatives, 2023**

All Sector	2023 Average Retail Electricity Price (2016 mills/kWh)				Percent Change from Baseline		
	Baseline	Final Rule	Less-Stringent Alt.	More-Stringent Alt.	Final Rule	Less-Stringent Alt.	More-Stringent Alt.
TRE	77.5	77.5	77.5	77.5	0%	0%	0%
FRCC	109.1	109.1	109.1	109.1	0%	0%	0%
MISW	98.4	98.4	98.4	98.4	0%	0%	0%
MISC	93.2	93.2	93.2	93.2	0%	0%	0%
MISE	89.8	89.8	89.8	89.8	0%	0%	0%
MISS	84.6	84.6	84.6	84.6	0%	0%	0%
ISNE	151.3	151.4	151.3	151.9	0%	0%	0%
NYCW	680.1	684.4	683.4	696.4	1%	0%	2%
NYUP	148.1	148.1	148.1	148.3	0%	0%	0%
PJME	140.4	141.4	141.2	144.4	1%	1%	2%
PJMW	93.2	93.2	93.2	93.3	0%	0%	0%
PJMC	79.8	79.8	79.8	79.9	0%	0%	0%
PJMD	73.9	73.9	73.8	74.0	0%	0%	0%
SRCA	97.6	97.5	97.5	97.6	0%	0%	0%
SRSE	104.4	104.4	104.4	104.4	0%	0%	0%
SRCE	76.3	76.3	76.3	76.3	0%	0%	0%
SPPS	79.9	79.9	79.9	80.0	0%	0%	0%
SPPC	103.0	103.0	103.0	103.0	0%	0%	0%
SPPN	63.6	63.6	63.6	63.6	0%	0%	0%
SRSG	103.3	103.3	103.3	103.3	0%	0%	0%
CANO	153.0	153.0	153.0	153.0	0%	0%	0%
CASO	186.3	186.3	186.3	186.3	0%	0%	0%
NWPP	72.7	72.7	72.7	72.7	0%	0%	0%
RMRG	96.0	96.0	96.0	96.0	0%	0%	0%
BASN	90.8	90.9	90.9	90.9	0%	0%	0%
NATIONAL	113.0	113.2	113.1	113.6	0%	0%	0%

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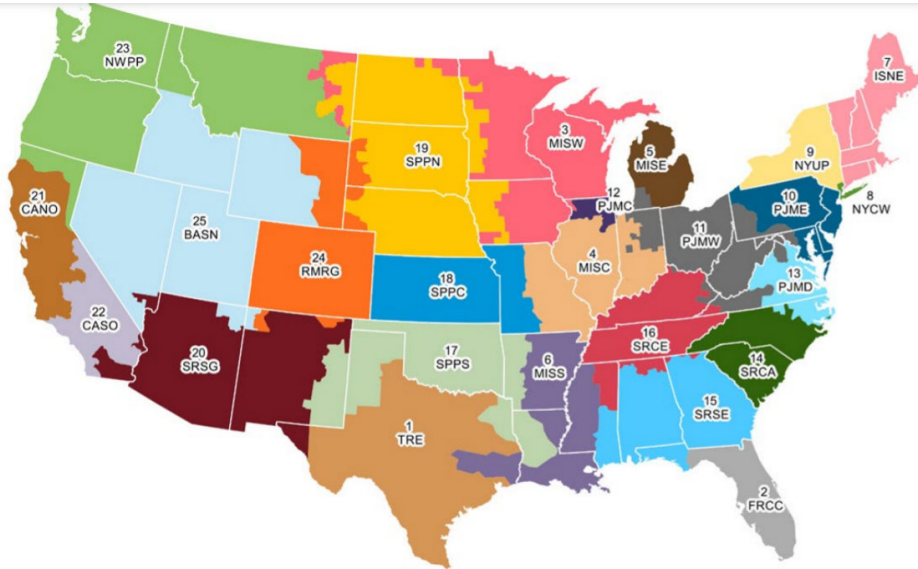
**Table 4-16. Average Retail Electricity Price by Region for the Baseline and the Regulatory Control Alternatives, 2025**

All Sector	2025 Average Retail Electricity Price (2016 mills/kWh)				Percent Change from Baseline		
	Baseline	Final Rule	Less-Stringent Alt.	More-Stringent Alt.	Final Rule	Less-Stringent Alt.	More-Stringent Alt.
TRE	71.6	72.7	72.5	83.9	2%	1%	16%
FRCC	98.1	98.1	98.1	98.1	0%	0%	0%
MISW	94.7	94.7	94.7	95.3	0%	0%	1%
MISC	87.6	87.5	87.4	89.8	0%	0%	3%
MISE	79.1	79.9	79.8	84.8	1%	1%	6%
MISS	77.6	77.9	77.6	79.4	0%	0%	2%
ISNE	134.7	134.8	134.8	135.5	0%	0%	1%
NYCW	180.1	180.3	180.1	180.7	0%	0%	0%
NYUP	114.8	114.9	114.7	115.4	0%	0%	1%
PJME	116.3	116.4	116.1	117.0	0%	0%	1%
PJMW	86.3	86.7	86.4	90.6	0%	0%	5%
PJMC	76.2	75.4	75.6	83.0	-1%	-1%	10%
PJMD	67.2	67.5	67.3	71.4	0%	0%	6%
SRCA	92.3	92.3	92.3	92.3	0%	0%	0%
SRSE	95.4	95.4	95.4	95.0	0%	0%	0%
SRCE	69.8	69.7	69.7	70.4	0%	0%	1%
SPPS	76.7	77.1	76.8	79.4	0%	0%	3%
SPPC	100.2	100.5	100.4	102.6	0%	0%	2%
SPPN	63.0	62.7	62.9	61.6	0%	0%	-2%
SRSR	99.5	99.5	99.5	99.5	0%	0%	0%
CANO	152.1	152.1	152.1	152.7	0%	0%	0%
CASO	186.6	186.5	186.6	187.1	0%	0%	0%
NWPP	72.2	72.2	72.2	72.4	0%	0%	0%
RMRG	90.8	90.9	90.8	91.0	0%	0%	0%
BASN	89.0	89.1	89.0	90.3	0%	0%	1%
NATIONAL	95.6	95.7	95.6	98.0	0%	0%	2%

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**Table 4-17. Average Retail Electricity Price by Region for the Baseline and the Regulatory Control Alternatives, 2030**

All Sector	2030 Average Retail Electricity Price (2016 mills/kWh)				Percent Change from Baseline		
	Baseline	Final Rule	Less-Stringent Alt.	More-Stringent Alt.	Final Rule	Less-Stringent Alt.	More-Stringent Alt.
TRE	79.2	83.0	83.1	78.4	5%	5%	-6%
FRCC	92.5	92.5	92.6	92.5	0%	0%	0%
MISW	90.6	90.6	90.7	90.6	0%	0%	0%
MISC	86.0	86.6	86.6	86.9	1%	1%	0%
MISE	102.1	102.0	102.1	102.0	0%	0%	0%
MISS	75.8	77.1	77.1	76.3	2%	2%	-1%
ISNE	144.6	145.2	145.2	145.8	0%	0%	0%
NYCW	190.3	192.1	192.2	194.1	1%	1%	1%
NYUP	117.0	118.7	118.9	120.4	2%	2%	1%
PJME	106.2	107.8	107.9	105.3	2%	2%	-2%
PJMW	91.9	92.5	92.5	92.0	1%	1%	-1%
PJMC	81.2	81.3	81.4	81.3	0%	0%	0%
PJMD	75.7	76.8	76.9	76.7	1%	2%	0%
SRCA	89.0	89.0	89.0	89.0	0%	0%	0%
SRSE	88.4	88.4	88.4	88.4	0%	0%	0%
SRCE	67.2	67.6	67.6	67.6	1%	1%	0%
SPPS	77.3	77.9	78.0	78.2	1%	1%	0%
SPPC	91.4	92.2	92.3	91.8	1%	1%	-1%
SPPN	63.3	63.0	63.0	63.2	-1%	-1%	0%
SRSG	91.6	91.5	91.4	91.7	0%	0%	0%
CANO	166.5	167.4	167.4	166.3	1%	1%	-1%
CASO	198.3	198.5	198.5	198.2	0%	0%	0%
NWPP	72.6	72.5	72.5	72.5	0%	0%	0%
RMRG	85.3	85.5	85.6	85.3	0%	0%	0%
BASN	86.4	87.3	87.3	87.6	1%	1%	0%
NATIONAL	96.1	96.9	97.0	96.3	1%	1%	-1%



**Figure 4-1. Electricity Market Module Regions**

Source: EIA ([http://www.eia.gov/forecasts/aeo/pdf/nerc\\_map.pdf](http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf))

#### 4.5.4 Emissions Reductions and Compliance Cost Assessment for Non-EGUs for 2026

As stated in Section 4.4, using 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 CMDDB, the EPA estimated NO<sub>x</sub> emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. The EPA did not estimate emissions reductions of SO<sub>2</sub>, PM<sub>2.5</sub>, CO<sub>2</sub> and other pollutants that may be associated with controls on non-EGU emissions units. Table 4-18 summarizes the industries, emissions unit types, control technologies, and number of emissions units estimated to be subject to the rule. The rule alternative includes an estimated 1,228 non-EGU emissions units. Table 4-19 summarizes the industries, emissions unit types, assumed control technologies, estimated annual total annual costs (2016\$), and estimated ozone season emissions reductions for the rule. Table 4-20 summarizes the industries, emissions unit types, assumed control technologies, and estimated average annual costs (2016\$). Lastly, Table 4-21 below summarizes the estimated



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reductions and estimated annual total and average annual costs (2016\$) for the less and more stringent alternatives.

Because the Transport FIP for the 2015 ozone NAAQS includes ozone season emissions limits for the non-EGU emissions units and because we do not know if all affected sources will run controls year-round or only during ozone season, we include estimates of ozone season NOx emissions reductions and not annual estimates in Table Table 4-19 and Table 4-21. Note that some of the EGU controls are assumed to run year-round. Also, because the Transport FIP for the 2015 ozone NAAQS includes emissions limits, and the non-EGU assessment does not account for growth in the affected industries and capital turnover over time, the reductions are estimated to be the same each year over the period from 2026 to 2042.

For additional 2026 non-EGU assessment results -- including (i) by state and (ii) by state and industry, estimated emissions reductions and costs, see the memorandum in the 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*.

**Table 4-18. Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies that Meet Final Emissions Limits, Estimated Number of Control Installations**

Industry/Industries	Emissions Unit Type	Assumed Control Technologies that Meet Final Emissions Limits	Estimated Number of Units Per Assumed Control
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engines	NSCR or Layered Combustion (Reciprocating)	323
		Layered Combustion (2-cycle Lean Burn)	394
		SCR (4-cycle Lean Burn)	158
		NSCR (4-cycle Rich Burn)	30
Cement and Concrete Product Manufacturing	Kiln	SNCR	16
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	19
Glass and Glass Product Manufacturing	Furnaces	LNB	61
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	LNB + FGR (Gas, No Coal or Oil)	151
Metal Ore Mining		SCR (Any Coal, Any Oil)	15
Basic Chemical Manufacturing			

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Industry/Industries	Emissions Unit Type	Assumed Control Technologies that Meet Final Emissions Limits	Estimated Number of Units Per Assumed Control
Petroleum and Coal Products Manufacturing			
Pulp, Paper, and Paperboard Mills			
Solid Waste Combustors and Incinerators <sup>a</sup>	Combustors or Incinerators	ANSCR	57
		LN <sup>TM</sup> and SNCR	4
<b>Total</b>			<b>1,228</b>

<sup>a</sup>Twelve MWCs have existing controls, and we estimated these units will use more reagent in those controls to meet the final emissions limits.

**Table 4-19. Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies, Estimated Total Annual Costs (2016\$), Estimated Ozone Season NOx Emissions Reductions in 2026**

Industry/Industries	Emissions Unit Type	Assumed Control Technologies that Meet Final Emissions Limits	Annual Costs (million 2016\$)	Ozone Season Emissions Reductions
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR	385	32,247
Cement and Concrete Product Manufacturing	Kiln	SNCR	10.1	2,573
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	3.58	408
Glass and Glass Product Manufacturing	Furnaces	LNB	7.05	3,129
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	SCR, LNB + FGR	8.84	440
Metal Ore Mining			0.621	18
Basic Chemical Manufacturing			49.7	1,748
Petroleum and Coal Products Manufacturing			5.13	147
Pulp, Paper, and Paperboard Mills			62.3	1,836
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN <sup>TM</sup> and SNCR	38.9	2,071
<b>Totals</b>			<b>572</b>	<b>44,616</b>

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**Table 4-20. Summary of Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies, Estimated Average Cost/Ton (2016\$)**

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
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 LNT <sup>TM</sup> and SNCR <sup>a</sup>	7,836
<b>Overall Average Cost/Ton</b>			<b>5,339</b>

**Commented [EO 1286653]:** As one example of comparing the more stringent option: What would the average cost/ton be for the more stringent option for this source? And why would that not be cost-effective?

**Commented [EPA54R53]:** As noted above and in the Agency's preamble responses, the more stringent alternative for the cement sector reflects estimated controls that are not widely demonstrated in practice in the US. While the average cost/ton may look "cost-effective" the control is not widely demonstrated in practice in the US.

This question was also discussed/addressed during a 3/6/2023 teleconference with OMB.

**Commented [EPA55R53]:** 3/10/2023: This point seems important; would recommend that EPA draft some brief text to provide this context for readers of the RIA

**Commented [EPA56R53]:** To address this comment, we added the following note at the bottom of Table 4-4 above - Note that for some industries the more stringent alternative reflects assumed technologies (and estimated emissions reductions) that are not widely demonstrated in practice in the U.S.

<sup>a</sup> Covanta has developed a proprietary low NO<sub>x</sub> combustion system (LNTM) that involves staging of combustion air. The system is a trademarked system and Covanta has received a patent for the technology.

**Table 4-21. Estimated Emissions Reductions for 2026-2042 (ozone season tons) and Estimated Annual Total Costs for the Less and More Stringent Alternatives**

Alternative	Ozone Season NO <sub>x</sub> Emissions Reductions	Annual Total Cost (million 2016\$) (Average Annual Cost/Ton)
Less Stringent Alternative	16,786	\$144 (\$3,573)
More Stringent Alternative	67,958	\$1,280 (\$7,852)

4.5.5 Total Emissions Reductions and Compliance Costs for EGUs and Non-EGUs

For select years between 2023 and 2042, Table 4-22 below summarizes the total estimated emissions reductions and undiscounted compliance costs for EGUs and non-EGUs for the final rule and the less and more stringent alternatives. For a complete stream of undiscounted cost values, please see Chapter 8, Table 8-6.

Table 4-23 below summarizes the present value (PV) and equivalent annualized value (EAV) of the total national compliance cost estimates for EGUs and non-EGUs for the final rule

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and the less and more stringent alternatives. We present the PV of the costs over the twenty-year period 2023 to 2042. We also present the EAV, which represents a flow of constant annual values that, had they occurred in each year from 2023 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost for each year of the analysis.

**Table 4-22. Total Estimated NO<sub>x</sub> Emissions Reductions (ozone season, thousand tons) and Compliance Costs (million 2016\$), 2023-2042**

		Final Rule	Less Stringent Alternative	More Stringent Alternative	Final Rule	Less Stringent Alternative	More Stringent Alternative
		Emissions Reductions (ozone season, thousand tons)			Compliance Costs (million 2016\$)		
2023	EGUs	10	10	10	57	56	49
	Non-EGUs	--	--	--	-	-	-
	<b>Total</b>	<b>10</b>	<b>10</b>	<b>10</b>	<b>57</b>	<b>56</b>	<b>49</b>
2026	EGUs	27	8	53	(5)	(35)	840
	Non-EGUs	45	17	68	570	140	1,300
	<b>Total</b>	<b>72</b>	<b>25</b>	<b>121</b>	<b>570</b>	<b>110</b>	<b>2,100</b>
2027	EGUs	20	6	46	24	(47)	760
	Non-EGUs	45	17	68	570	140	1,300
	<b>Total</b>	<b>65</b>	<b>23</b>	<b>114</b>	<b>600</b>	<b>97</b>	<b>2,000</b>
2030	EGUs	36	35	33	710	770	840
	Non-EGUs	45	17	68	570	140	1,300
	<b>Total</b>	<b>81</b>	<b>52</b>	<b>101</b>	<b>1,300</b>	<b>920</b>	<b>2,100</b>
2035	EGUs	30	30	29	820	850	590
	Non-EGUs	45	17	68	570	140	1,300
	<b>Total</b>	<b>75</b>	<b>47</b>	<b>97</b>	<b>1,400</b>	<b>990</b>	<b>1,900</b>
2042	EGUs	30	30	29	820	830	600
	Non-EGUs	45	17	68	570	140	1,300
	<b>Total</b>	<b>75</b>	<b>47</b>	<b>97</b>	<b>1,400</b>	<b>970</b>	<b>1,900</b>

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**Table 4-23. Total National Compliance Cost Estimates (millions of 2016\$) for the Final Rule and the Less and More Stringent Alternatives**

	Final Rule		Less Stringent Alternative		More Stringent Alternative	
	3 Percent	7 Percent	3 Percent	7 Percent	3 Percent	7 Percent
Present Value EGU 2023-2042	\$6,800	\$3,900	\$6,800	\$3,900	\$9,500	\$6,500
Present Value Non-EGU 2023-2042	\$6,700	\$4,300	\$1,700	\$1,100	\$15,000	\$9,500
<b>Present Value Total 2023-2042</b>	<b>\$13,000</b>	<b>\$8,200</b>	<b>\$8,500</b>	<b>\$5,000</b>	<b>\$24,000</b>	<b>\$16,000</b>
EGU Equivalent Annualized Value	\$460	\$370	\$460	\$370	\$640	\$620
Non-EGU Equivalent Annualized Value	\$450	\$400	\$110	\$100	\$1,000	\$900
<b>Total Equivalent Annualized Value</b>	<b>\$910</b>	<b>\$770</b>	<b>\$570</b>	<b>\$470</b>	<b>\$1,600</b>	<b>\$1,500</b>

Note: Values have been rounded to two significant figures

#### 4.6 Social Costs

As discussed in the EPA’s *Guidelines for Preparing Economic Analyses*, social costs are the total economic burden of a regulatory action (U.S. EPA, 2010). This burden is the sum of all opportunity costs incurred due to the regulatory action, where an opportunity cost is the value lost to society of any goods and services that will not be produced and consumed because of reallocating some resources towards pollution mitigation. Estimates of social costs may be compared to the social benefits expected because of a regulation to assess its net impact on society.

The social costs of this regulatory action will not necessarily be equal to the expenditures by the electricity sector and other affected industries to comply with the final rule. Nonetheless, here we use total national compliance costs for EGUs and non-EGUs as a proxy for social costs. Table above presents the total annual estimated compliance costs for EGUs for 2023 and EGUs and non-EGUs for 2026-2042.

The compliance cost estimates for EGUs in the rule and more or less stringent regulatory control alternatives presented above are the change in expenditures by the electricity generating

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sector required by the power sector for compliance under each alternative. The change in the expenditures required by the power sector to achieve and maintain compliance reflect the changes in electricity production costs resulting from application of NO<sub>x</sub> control strategies necessary to comply with the emissions budgets and the backstop emission rate. The production cost changes include changes in fuel expenditures.

Ultimately, depending on the market structure and the demand and supply price elasticities for electricity, some compliance costs may be borne by electricity consumers through higher electricity prices. Furthermore, the share of compliance costs ultimately borne by owners of electricity generating capacity and other capital may be borne unevenly, with some firms becoming more profitable as a result of the regulation. These asset owners and electricity consumers include U.S. citizens and residents as well as non-residents (e.g., foreign owners of electricity-consuming commercial enterprises). For additional discussion of impacts on fuel use and electricity prices, see Section 4.5.3 above.

The compliance cost estimates for non-EGUs in the rule and more or less stringent regulatory control alternatives are the change in expenditures by the industries required for compliance under each alternative. The change in the expenditures required by the industries to maintain compliance reflect the changes in production costs resulting from application of NO<sub>x</sub> control technologies or measures. As in the power sector, ultimately, depending on market structure and the demand and supply price elasticities for these industrial products, some part of the compliance costs may be borne by consumers through higher prices, and these costs are distributed among U.S. citizens and residents and foreign asset owners.

For non-EGUs the estimated compliance costs in Table 4-22 are derived using the control measures database, and for EGUs the estimated compliance costs are generated using the Integrated Planning Model (IPM). IPM solves for the least-cost approach to meet new regulatory requirements in the electricity sector with highly detailed information on electricity generation and air pollution control technologies and primary energy sector market conditions (coal and natural gas) while meeting fixed electricity demands, regulatory requirements, and other constraints. However, potential effects outside of the electricity, coal and natural gas sectors are not evaluated within IPM.

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Changes in production in a directly regulated sector may have indirect effects on a myriad of other markets when output from that sector – for this rule electricity and certain industrial products - is used as an input in the production of many other goods. It may also affect upstream industries that supply goods and services to the sector, along with labor and capital markets, as these suppliers alter production processes in response to changes in factor prices. In addition, households may change their demand for particular goods and services due to changes in the price of electricity and other final goods prices.

When new regulatory requirements are expected to result in effects outside of regulated and closely related sectors, a key challenge is determining whether they are of sufficient magnitude to warrant explicit evaluation (Hahn and Hird 1990). It is not possible to estimate the magnitude and direction of these potential effects outside of the regulated sector(s) without an economy-wide modeling approach. For example, studies of air pollution regulations for the power sector have found that the social costs and benefits may be greater or lower than when secondary market impacts are considered, and that the direction of the estimates may depend on the form of the regulation (e.g., Goulder et al. 1999, Williams 2002, Goulder et al. 2016).

Economy-wide models - and, more specifically, computable general equilibrium (CGE) models - are analytical tools that can be used to evaluate the broad impacts of a regulatory action. A CGE-based approach to cost estimation concurrently considers the effect of a regulation across all sectors in the economy. It is structured around the assumption that, for some discrete period of time, an economy can be characterized by a set of equilibrium conditions in which supply equals demand in all markets. When the imposition of a regulation alters conditions in one market, a general equilibrium approach will determine a new set of prices for all markets that will return the economy to equilibrium. These prices in turn determine the outputs and consumption of goods and services in the new equilibrium. In addition, a new set of prices and demands for the factors of production (labor, capital, and land), the returns to which compose the income of businesses and households, will be determined in general equilibrium. The social cost of the regulation can then be estimated by comparing the value of variables in the pre-regulation “baseline” equilibrium with those in the post-regulation, simulated equilibrium.

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In 2015, the EPA established a Science Advisory Board (SAB) panel to consider the technical merits and challenges of using economy-wide models to evaluate costs, benefits, and economic impacts in regulatory development. In its final report (U.S. EPA 2017), the SAB recommended that the EPA begin to integrate CGE modeling into regulatory analysis to offer a more comprehensive assessment of the effects of air regulations. The SAB noted that CGE models can provide insight into the likely social costs of a regulation even when they do not include a characterization of the likely social benefits of the regulation. CGE models may also offer insights into the ways costs are distributed across regions, sectors, or households.

The SAB also noted that the case for using CGE models to evaluate a regulation's effects is strongest when the costs of compliance are expected to be large in magnitude and the sector has strong linkages to the rest of the economy. The report also noted that the extent to which CGE models add value to the analysis depends on data availability. CGE models provide aggregated representations of the entire economy and are designed to capture substitution possibilities between production, consumption, and trade; interactions between economic sectors; and interactions between a policy shock and pre-existing distortions, such as taxes. However, one also needs to adequately represent a regulation in the model to estimate its effects.

In response to the SAB's recommendations, the EPA built a new CGE model called SAGE. A second SAB panel performed a peer review of SAGE, and the review concluded in 2020.<sup>115</sup> While the EPA now has a peer reviewed CGE model for analyzing the potential economy-wide effects of regulations, we have not used the model in the RIA for this rule due to the expedited rulemaking timeline. However, the EPA continues to be committed to the use of CGE models to evaluate the economy-wide effects of its regulations.

#### **4.7 Limitations**

The EPA's modeling is based on expert judgment of various input assumptions for variables whose outcomes are uncertain. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls and new capacity construction costs to support a reasonable modeling framework for analyzing the cost, emission

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<sup>115</sup> See U.S. EPA (2020). The model peer review and other SAB reports can be downloaded at: <https://sab.epa.gov/ords/sab/f?p=100:12:15036376991605:::12::>



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changes, and other impacts of regulatory actions for EGUs. The annualized cost of the rule for EGUs, as quantified here, is the EPA’s best assessment of the cost of implementing the rule for the power sector. These costs are generated from rigorous economic modeling of changes in the power sector due to implementation of the rule.

The IPM-projected annualized cost estimates of private compliance costs provided in this analysis are meant to show the increase in production (generating) costs to the power sector in response to the rule. To estimate these annualized costs, as discussed earlier in this chapter, 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 to calculate annual costs. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. The private compliance costs presented earlier are the EPA’s best estimate of the direct private compliance costs of the rule.

In addition, there are several key areas of uncertainty related to the electric power sector that are worth noting, including:

- Electric demand: The analysis includes an assumption for future electric demand. To the extent electric demand is higher and lower, it may increase/decrease the projected future composition of the fleet.
- Natural gas supply and demand: The recent run up in fuel costs is reflected through an increase in natural gas price inputs for 2023 and 2025 model run years, and coal price inputs in the 2023 model run year. Large increases in supply over the last few years, and relatively low prices, are represented in the analysis for subsequent run years. To the extent prices are higher or lower, it would influence the use of natural gas for electricity generation and overall competitiveness of other EGUs (e.g., coal and nuclear units).
- Longer-term planning by utilities: Many utilities have announced long-term clean energy and/or climate commitments, with a phasing out of large amounts of coal capacity by 2030 and continuing through 2050. These announcements, some of which are not legally binding, are not necessarily reflected in the baseline, and may alter the amount of coal capacity projected in the baseline that would be covered under this rule.

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- Inflation Reduction Act (IRA): The IRA was passed in August of 2022, at which time the modeling in support of this rule was in an advanced stage and timing considerations did not allow for incorporation of the effects of this legislation. In order to illustrate the impact of the IRA on this rulemaking, the EPA included a baseline that incorporates key provisions of the IRA as well as imposing the final rule as modeled in this RIA on that baseline. The results from these scenarios are compared with the non-IRA scenarios and provided in Appendix 4A. The analysis quantifies total costs and emission changes but does not quantify the benefits associated with these emission changes.

These are key uncertainties that may affect the overall composition of electric power generation fleet and could thus have an effect on the estimated costs and impacts of this action. However, these uncertainties would affect the modeling of the baseline and illustrative policy alternatives similarly, and therefore the impact on the incremental projections (reflecting the potential costs/benefits of the illustrative final rule alternative) would be more limited and are not likely to result in notable changes to the assessment of the Transport FIP for the 2015 ozone NAAQS found in this chapter. While it is important to recognize these key areas of uncertainty, they do not change the EPA’s overall confidence in the estimated impacts of the illustrative final rule alternative presented in this chapter. The EPA continues to monitor industry developments and makes appropriate updates to the modeling platforms in order to reflect the best and most current data available.

The baseline includes modeling to capture the finalized 2020 effluent Limitation Guidelines (ELG), it also incorporates information provided by owners of affected facilities to state permitting authorities in October 2021 that indicate their likely compliance pathway, including retirement by 2028. Potential future incorporation of this information may result in additional coal plant retirements relative to the baseline scenario, which would - all else equal - reduce the modeled costs and benefits of the rule depending on the extent that these retirements occur before compliance deadlines for this action. Similarly, the baseline accounts for the effect of expected compliance methods for the 2020 CCR Rule. However, plants may adopt compliance methods that are different than those represented in the baseline.

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As discussed in section 4.3.2, IPM v.6.20 does not have the capacity to endogenously determine whether to maximize the use of existing EGU post-combustion NO<sub>x</sub> controls (i.e., SCR), or install/upgrade combustion controls in response to a regulatory control requirement. These decisions were imposed exogenously on the model, as documented in section 4.3.2. While the emissions projections reflect operation of these controls, the projected compliance costs were supplemented with exogenously estimated costs of optimizing SCR operation, optimizing SNCR operation, and installing/upgrading combustion controls (see section 4.3.3). As a result of this modeling approach, the dispatch decisions made within the model do not take into consideration the additional operating costs associated with these three types of compliance strategies (the operating costs of the units on which these strategies are imposed do not reflect the additional costs of these strategies). The effect of changes in facility and system-wide emissions from these changes in operating costs are also not accounted for in the air quality modeling for the regulatory alternatives described in Chapter 3.

The impacts of the Later Model Year Light-Duty Vehicle GHG Emissions Standards<sup>116</sup> is not captured in the baseline. This rule is projected to increase the total demand for electricity by 0.5% in 2030 and 1% in 2040 relative to 2020 levels.<sup>117</sup> This translates into a 0.4% increase in electricity demand in 2030 and a 0.8% increase in electricity demand in 2040 relative to the baseline electricity demand projections assumed in this analysis. The impact of the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review<sup>118</sup> are also not included in this analysis. Inclusion of these standards would likely increase the price of natural gas modestly as a result of limitations on the usage of reciprocating internal combustion engines in the pipeline transportation of natural gas. All else equal inclusion of these two programs would likely result in a modest increase in the total cost of compliance for this rule.

Lastly, the EPA estimated the non-EGU emissions units subject to the final rule using the 2019 inventory from the emissions inventory system (EIS) and supplemented the information by

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<sup>116</sup> Available at: <https://www.federalregister.gov/documents/2021/08/10/2021-16582/revise-2023-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-standards>

<sup>117</sup> Regulatory Impact Analysis available at: <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1012ONB.pdf>

<sup>118</sup> Available at: <https://www.federalregister.gov/documents/2021/11/15/2021-24202/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for>

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reviewing online permits for the estimated emissions units in the Cement and Concrete Product Manufacturing, Glass and Glass Product Manufacturing, and Iron and Steel Mills and Ferroalloy Manufacturing industries. Because the number of estimated emissions units for reciprocating internal combustion engines and boilers was larger, the EPA did a limited permit review for those units. For boilers, the EPA also reviewed the database used in the July 2022 revised Boiler MACT.<sup>119</sup> Using 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, the EPA estimated NO<sub>x</sub> emissions reductions and costs for the year 2026. The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions reductions and costs associated with the assumed control technologies that would meet the final emissions limits. The control cost estimates assume an average level of retrofit difficulty for control applications, and do not include monitoring, recordkeeping, reporting, or testing costs. It is not possible to determine whether this approach leads to an overestimate or underestimate of the costs, NO<sub>x</sub>, and other pollutant emissions changes, benefits, and other impacts, including the effect on downwind receptors, of the rule and the analyzed alternatives. Between proposal and the final rule, based on comments received and additional research about whether a unit already had an existing control, the EPA updated the estimated emissions reductions and costs reflecting this information. For the final rule, if the EPA was aware of the presence of a control, in many cases it then assumed that the unit did not need additional control. And, if it was not aware of the presence of a control, it assumed that a control was required, and the costs and benefits were accounted for based on this approach.

We are not able to project potential changes in the number of existing and new units resulting from industry growth or capital turnover, over time in the baseline. The effects of the uncertainty in these changes on costs, emissions reductions and benefits of the final rule are ambiguous. We are also not able to project whether the emissions limitations would require

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<sup>119</sup> The EPA did not run the Control Strategy Tool to estimate emissions reductions and costs and programmed the assessment using R. R is a free software environment for statistical computing and graphics. Additional information is available here: <https://www.r-project.org/>. The R code that processed the data to estimate the emissions reductions and costs is available upon request.

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further NO<sub>x</sub> emissions reductions at new units relative to what is required of them in the baseline.

Also, we are not able to project whether non-EGU units will make operational changes for compliance with the final rule and whether those changes will lead to changes in emissions other than NO<sub>x</sub>. For example, if the non-EGUs respond to this final rule by replacing an old unit with a newer, more efficient unit, emissions of other pollutants from non-EGUs may also decrease. Furthermore, certain non-EGUs may choose compliance approaches for the final rule that also incidentally reduce NO<sub>x</sub> emissions outside of the ozone season, which would yield additional benefits from reduced PM<sub>2.5</sub> exposure. If ultimate compliance with this final rule incidentally reduces NO<sub>x</sub> and other pollutants emissions outside of the ozone season, the benefits from non-EGUs, all else equal, are likely underestimated.

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#### **APPENDIX 4A: INFLATION REDUCTION ACT EGU SENSITIVITY RUN RESULTS**

In this appendix we describe the EGU compliance behavior, costs, and emissions reductions that include adjustments made to the IPM baseline for the Inflation Reduction Act (IRA) of 2022. The IRA includes significant additional new generation incentives targeting more efficient and lower-emitting sources of generation that is likely to meaningfully affect the U.S. generation mix in the future and increase the pace of new lower-emitting generation replacing some of older higher-emitting generating capacity. This supplementary analysis quantifies the incremental impacts of the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS) under the alternative baseline characterization and compares impacts with the main analysis described in Chapter 4. **As described in Chapter 4, the model runs that inform air quality do not include the IRA due to time limitations. However, for completeness this appendix seeks to quantify the effect on the expected power sector outcomes of the final rule with this alternative baseline.**

##### **4A.1 Modeling the IRA in IPM**

This supplementary analysis incorporates several key aspects of the IRA that influence EGU behavior in the IPM baseline. The analysis addresses aspects of the IRA to the extent possible given overall timing limitations in the production of this RIA and uncertainties around some of the final rule’s potential impacts. The main IPM model updates are included in Table 4A.1. No adjustments are made to electricity demand to reflect the impact of incremental electrification, since this parameter is subject to a significant amount of uncertainty and is more likely to drive results later in the forecasted period.

**Commented [EO 1286657]:** And as a result, may understate the effects of the IRA on the benefits of future generation shifting?

**Commented [EPA58R57]:** The IRA is likely to make generation shifting a more attractive compliance option. However, we do not include generation shifting to derive budgets, so it would not have an impact on budget setting.

**Commented [EPA59R57]:** 3/10/2023: Understood that generation shifting will not impact budget setting. Separately, we request that EPA provide some language in both the preamble and RIA to generally and directionally discuss the IRA’s impact on estimated benefits (or lack thereof, as appropriate)

**Commented [EPA60R57]:** Please see response and addition in Section 4A.1.2 below.

**Table 4A-1. IRA Provisions Modeled in IPM**

<p><b>PTC/ITC and Clean Energy Tax Credits</b></p> <ul style="list-style-type: none"><li>• Wage and apprenticeship requirements are assumed to be met.</li><li>• Extended to include stand-alone storage and new nuclear resources.</li><li>• All storage assumed to qualify for 10% bonus energy tax credit.</li><li>• All other technologies assumed to qualify for a prorated bonus energy tax credit based on the share of energy community land area to total land area within an IPM zone.</li><li>• Credits remain in place until later of 2032 or the year in which power sector emissions are 25% or less of 2021 historical levels (used as a proxy for 2022 emissions).</li></ul> <p><b>Capital Cost Step Adder Adjustment</b></p> <ul style="list-style-type: none"><li>• The short-term capital cost adder step widths for solar, wind, geothermal, hydro, and nuclear technologies are relaxed to reflect the IRA’s impact on improvements to manufacturing capability. The scalars are linearly interpolated in between 2023 and 2035. However, a scalar of 1.0 is also used for 2025 to reflect near term limitations.</li></ul> <p><b>45(q) Tax Credits for CCUS</b></p> <ul style="list-style-type: none"><li>• A CO<sub>2</sub> storage tax credit of \$60/metric tonne for EOR sites and \$85/metric tonne for non EOR sites is provided to the CCS investments made in the 2030 and 2035 run years.</li></ul> <p><b>Other</b></p> <ul style="list-style-type: none"><li>• Nuclear endogenous retirements are disabled. Nuclear units are retired per a predetermined retirement schedule. Exceptions are made if a specific unit’s age based on its license expiration date is greater than 60 years.</li><li>• Lower price steps are added to the 2045 and 2050 natural gas supply curves to reflect lower gas consumption.</li><li>• The CO<sub>2</sub> financing uncertainty adder is removed from fossil builds.</li></ul>
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**Commented [EO 1286661]:** A justification of this change would be helpful as it is not something that clearly arises from an IRA provision or authority.

**Commented [EPA62R61]:** The CO2 uncertainty adder reflects additional uncertainty around cost recovery under possible future GHG reduction programs. The IRA is a significant GHG reduction program and as such reduces this uncertainty (i.e., baseline conditions now explicitly include GHG reduction measures).

Throughout the rest of this appendix, costs and emissions outcomes are provided for the Baseline and final rule with and without the IRA active to provide a comparison between compliance with the final rule under each baseline characterization.

*4A.1.1 Compliance Cost Assessment for EGUs*

The estimates of incremental costs of supplying electricity for the final rule with and without IRA provisions are presented in Table 4A-2. Since the final rule generally does not result in significant additional recordkeeping, monitoring or reporting requirements for EGUs, the costs associated with compliance, monitoring, recordkeeping, and reporting requirements are not included within the estimates in this table.

**Commented [EO 1286663]:** Phrasing? Is this a typo, “in significant” e.g.?

**Commented [EPA64R63]:** Yes, thank you.



**Table 4A-2. National Power Sector Compliance Cost Estimates (millions of 2016\$) for the Final Rule With and Without the IRA**

	Final Rule + IRA	Final Rule
2023-2027 (Annualized)	13	14
2023-2045 (Annualized)	196	449
2023 (Annual)	47	57
2024 (Annual)	-17	-5
2025 (Annual)	-17	-5
2026 (Annual)	-17	-5
2027 (Annual)	67	24
2030 (Annual)	577	705
2035 (Annual)	297	817
2045 (Annual)	163	182

“2023-2027 (Annualized)” reflects total estimated annual compliance costs levelized over the period 2023 through 2027 and discounted using a 3.76 real discount rate.<sup>120</sup> This does not include compliance costs beyond 2027. “2023-2045 (Annualized)” reflects total estimated annual compliance costs levelized over the period 2023 through 2045 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2045. “2023 (Annual)” through “2045 (Annual)” costs reflect annual estimates in each of those years.<sup>121</sup>

The impact of the IRA is to increase the economic competitiveness of lower emitting and renewable technologies relative to the higher emitting technologies that this rule seeks to regulate. Since the IRA incentives persist over the forecast period, we do not see the “rush to build”~~“build”~~ that characterizes modeling of incentives that will expire in the near future. As such the impact of the IRA is felt to a greater extent over the medium and longer term when the incentives are further aided by sector cost declines and performance improvements assumed over time. As a result, compliance costs are projected to be similar to the scenario without the IRA over the five-year period (2023-27) but are less than half the costs over the 2023-2045 period (\$449 million 2016\$ without the IRA and \$196 million 2016\$ including the IRA). Moreover, the costs peak in 2030 at \$577 million 2016\$ with the IRA as compared to peaking in 2035 at \$817 million 2016\$ under the no IRA scenario.

<sup>120</sup> This table reports compliance costs consistent with expected electricity sector economic conditions. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM’s objective function for cost-minimization. The NPV of costs was then used to calculate the levelized annual value over a 5-year period (2023-2027) and a 20-year period (2023-2042) using the 3.76% rate as well.

<sup>121</sup> Cost estimates include financing charges on capital expenditures that would reflect a transfer and would not typically be considered part of total social costs.

**Commented [EO 1286665]:** Why is the annualized cost so much higher than the general annual cost for reported years? Are significant values in non-reported years skewing the annualized figure?

**Commented [EPA66R65]:** The annualized costs are based on run year mapping. The run year structure is as follows:

Run year 2023 is mapped to calendar year 2023, while run year 2025 is mapped to 2024-26, run year 2028 is mapped to 2027-29, run year 2030 is mapped to 2030-31, run year 2035 is mapped to 2032-37, run year 2040 is mapped to 2038-42, while run year 2045 is mapped to 2043-47

Hence, when we map the run year values to calendar years and then calculate the present value we end up with a larger value since there are large costs in RY2030/35/40 and 45.

**Commented [EPA67R65]:** 3/10/2023: Is this how EPA would expect costs to actually play out over time, or is this a quirk of mapping the run years to calendar years? Would help to clarify in the text as appropriate.

**Commented [EPA68R65]:** EPA would expect costs to follow a similar trajectory, i.e., be highest when the backstop rate is in effect, which would be phased in by 2030.

4A.1.2 Emissions Reduction Assessment for EGUs

As indicated in Chapter 1, the NO<sub>x</sub> emissions reductions are presented in this RIA from 2023 through 2045 and are based on IPM projections. As outlined in Section 4.3.2 IPM is operating existing and newly installed controls seasonally based on historical operation patterns and seasonal and annual emission constraints within the model. Table 4A.3 presents the estimated reduction in power sector NO<sub>x</sub> emissions resulting from compliance with the final rule in the 22 states, as well as the impact on other states both with and without the IRA. The emission reductions follow an expected pattern: near term NO<sub>x</sub> emissions reductions are similar with and without the IRA in place, while longer-term reductions are lower in the presence of the IRA, reflecting a lower emitting baseline as a result of the greater levels of clean energy incentives modeled. Differences in emissions reductions after 2030 suggest that some units that are projected to retire in 2030 due to the final rule reported in Chapter 4 have already been retired due to the IRA by this point. Further, the EPA observes that the differences in estimated costs and emissions reductions in the IRA sensitivity suggests that there would also be differences in estimated health and climate benefits under this scenario, although the Agency did not have time under this rulemaking schedule to quantify those differences.

**Table 4A-3. EGU Ozone Season NO<sub>x</sub> Emissions and Emissions Changes (thousand tons) for the Baseline run and Final Rule with and without IRA from 2023 - 2045**

Ozone Season NO <sub>x</sub> (Thousand tons)	Total Emissions				Change from Baseline run		
	Baseline run + IRA	Final Rule + IRA	Baseline run	Final Rule	With IRA	Without IRA	
2023	22 States	229	220	230	220	-10	-10
	Other States	144	144	143	143	0	0
	Nationwide	373	363	373	363	-10	-10
2024	22 States	201	182	203	181	-20	-22
	Other States	127	129	128	129	2	1
	Nationwide	329	311	331	310	-18	-21
2025	22 States	173	144	176	143	-30	-34
	Other States	111	114	113	115	3	2
	Nationwide	284	258	289	258	-26	-32
2026	22 States	158	135	167	140	-23	-27
	Other States	104	106	107	109	2	2
	Nationwide	262	241	274	248	-20	-25

**Commented [EO 1286669]:** Because the effects on benefits are not modeled, EPA should describe generally the effects that an IRA baseline would have on the rule’s projected emissions reductions, health benefits, climate benefits, etc.

**Commented [EPA70R69]:** The EPA can’t reliably characterize the estimated reductions and health and climate benefits without directly estimating emissions reductions and modeling the benefits.

**Commented [EPA71R69]:** 3/10/2023: Please add some clarifying text to match the preamble

**Commented [EPA72R69]:** Per 3/10/23 teleconference, we added note text, which is consistent with text added to preamble text.

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2027	22 States	142	126	157	137	-16	-20
	Other States	97	98	101	103	2	2
	Nationwide	239	225	258	239	-15	-19
2028	22 States	127	117	147	134	-10	-14
	Other States	90	90	95	96	1	2
	Nationwide	217	208	242	230	-9	-12
2030	22 States	110	82	137	101	-28	-36
	Other States	84	85	91	93	0	2
	Nationwide	195	167	228	194	-28	-34
2035	22 States	58	51	132	101	-8	-30
	Other States	50	50	88	89	-1	1
	Nationwide	108	100	220	190	-8	-29
2040	22 States	56	45	119	89	-11	-30
	Other States	38	38	79	79	0	0
	Nationwide	94	84	198	169	-11	-30
2045	22 States	46	41	102	80	-5	-22
	Other States	36	36	76	76	0	0
	Nationwide	82	77	178	156	-5	-22

In addition to the ozone season NO<sub>x</sub> reductions, there will also be reductions of other air emissions associated with EGUs burning fossil fuels (i.e., co-pollutants) that result from compliance strategies to reduce seasonal NO<sub>x</sub> emissions. These other emissions include the annual total changes in emissions of NO<sub>x</sub>, SO<sub>2</sub>, CO<sub>2</sub>, and direct PM<sub>2.5</sub> emissions changes. The emissions reductions are presented in Table 4A-4.

**Table 4A-4. EGU Annual Emissions and Emissions Changes for Annual NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, and CO<sub>2</sub> for the Baseline run and Final Rule with and without IRA from 2023 - 2045**

	Annual NO <sub>x</sub> (Thousand Tons)	Total Emissions		Change from Baseline run			
		Baseline run + IRA	Final Rule + IRA	Baseline run	Final Rule	With IRA	Without IRA
2023	22 States	560	545	561	546	-15	-15
	Other States	329	329	328	329	0	0
	Nationwide	889	874	889	874	-15	-15
2024	22 States	490	467	491	464	-23	-26
	Other States	284	286	286	287	2	1
	Nationwide	774	753	777	752	-21	-25
2025	22 States	419	388	420	383	-31	-38
	Other States	239	243	244	246	4	2

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	Nationwide	659	631	664	629	-27	-35
2026	22 States	381	357	398	367	-24	-31
	Other States	225	228	232	234	3	2
	Nationwide	606	585	630	601	-21	-29
2027	22 States	342	326	375	351	-17	-24
	Other States	211	213	220	222	2	2
	Nationwide	553	539	595	573	-15	-22
2028	22 States	304	295	353	336	-9	-17
	Other States	197	198	208	210	1	1
	Nationwide	500	492	561	545	-8	-16
2030	22 States	261	199	324	261	-63	-64
	Other States	186	187	208	210	1	1
	Nationwide	447	386	533	471	-62	-62
2035	22 States	131	110	304	254	-21	-49
	Other States	102	103	197	201	1	3
	Nationwide	233	213	501	455	-20	-46
2040	22 States	100	87	267	221	-13	-46
	Other States	80	80	173	174	0	1
	Nationwide	180	167	440	395	-13	-45
2045	22 States	82	79	218	195	-4	-23
	Other States	68	69	160	160	0	0
	Nationwide	151	148	378	355	-3	-23

	Annual SO <sub>2</sub> (thousand tons)	Total Emissions		Change from Baseline run			
		Baseline run + IRA	Final Rule + IRA	Baseline run	Final Rule	With IRA	Without IRA
2023	22 States	908	912	916	915	4	-1
	Other States	280	280	279	279	0	0
	Nationwide	1188	1192	1195	1194	4	-1
2024	22 States	778	765	787	766	-13	-21
	Other States	235	236	239	240	2	1
	Nationwide	1012	1001	1025	1006	-11	-19
2025	22 States	647	618	657	617	-29	-40
	Other States	189	192	199	201	3	2
	Nationwide	837	810	856	818	-26	-38
2026	22 States	540	520	574	543	-20	-31
	Other States	169	172	181	183	2	2
	Nationwide	710	692	755	726	-18	-29
	22 States	433	423	491	469	-10	-22

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2027	Other States	150	151	163	164	1	1
	Nationwide	583	574	654	633	-9	-21
2028	22 States	326	326	408	395	-1	-13
	Other States	130	130	145	145	0	0
	Nationwide	456	455	553	540	-1	-13
2030	22 States	247	158	385	289	-88	-95
	Other States	126	128	147	150	2	2
	Nationwide	373	286	532	439	-87	-93
2035	22 States	109	61	366	342	-47	-24
	Other States	49	50	135	138	1	3
	Nationwide	157	111	501	480	-46	-21
2040	22 States	64	44	305	279	-20	-26
	Other States	34	34	126	127	0	1
	Nationwide	98	78	432	406	-20	-25
2045	22 States	36	34	220	206	-2	-15
	Other States	22	22	128	128	0	0
	Nationwide	58	56	349	334	-2	-15

	Annual PM2.5 (thousand tons)	Total Emissions		Change from Baseline run			
		Baseline run + IRA	Final Rule + IRA	Baseline run	Final Rule	With IRA	Without IRA
2023	22 States	75	75	63	63	0	0
	Other States	47	47	40	40	0	0
	Nationwide	122	122	103	103	0	0
2024	22 States	67	66	57	56	-1	-1
	Other States	42	42	36	36	0	0
	Nationwide	109	108	93	92	-1	-1
2025	22 States	58	57	51	49	-2	-2
	Other States	37	37	33	33	0	0
	Nationwide	96	94	84	82	-1	-2
2026	22 States	55	54	49	48	-1	-1
	Other States	36	36	33	33	0	0
	Nationwide	91	90	82	81	-1	-1
2027	22 States	51	51	48	47	0	-1
	Other States	35	35	32	32	0	0
	Nationwide	87	86	80	80	0	-1
2028	22 States	48	48	47	46	0	0
	Other States	34	34	32	32	0	0
	Nationwide	82	82	79	78	0	0

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2030	22 States	45	39	45	43	-6	-2
	Other States	33	33	32	32	0	0
	Nationwide	78	72	76	75	-5	-1
2035	22 States	30	28	46	44	-2	-2
	Other States	21	21	30	30	0	0
	Nationwide	51	49	75	74	-2	-1
2040	22 States	26	25	44	43	-1	-2
	Other States	18	18	28	28	0	0
	Nationwide	44	43	73	71	-1	-2
2045	22 States	23	23	42	42	0	0
	Other States	17	17	28	28	0	0
	Nationwide	40	40	70	70	0	0

	Annual CO <sub>2</sub> (million short tons)	Total Emissions			Change from Baseline run		
		Baseline run + IRA	Final Rule + IRA	Baseline run	Final Rule	With IRA	Without IRA
2023	22 States	1030	1030	1033	1032	0	0
	Other States	592	592	591	592	0	0
	Nationwide	1622	1622	1624	1624	0	0
2024	22 States	950	941	947	935	-10	-12
	Other States	538	540	539	541	3	2
	Nationwide	1488	1481	1487	1476	-7	-10
2025	22 States	870	851	862	838	-19	-24
	Other States	483	488	488	491	5	3
	Nationwide	1354	1340	1350	1329	-14	-21
2026	22 States	825	813	844	826	-13	-18
	Other States	467	471	477	480	4	3
	Nationwide	1292	1283	1322	1306	-9	-16
2027	22 States	780	774	827	814	-7	-13
	Other States	450	454	467	469	3	2
	Nationwide	1231	1227	1294	1284	-3	-10
2028	22 States	735	735	809	803	-1	-7
	Other States	434	436	457	459	3	2
	Nationwide	1169	1171	1266	1261	2	-5
2030	22 States	660	611	784	753	-49	-31
	Other States	390	397	450	455	7	5
	Nationwide	1050	1008	1235	1209	-42	-26
2035	22 States	416	397	792	774	-19	-19
	Other States	240	241	436	438	1	2

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	Nationwide	656	638	1228	1212	-18	-16
	22 States	352	342	727	706	-11	-21
2040	Other States	211	211	411	411	0	1
	Nationwide	563	553	1138	1117	-10	-20
	22 States	330	327	670	662	-3	-9
2045	Other States	205	205	400	400	0	0
	Nationwide	535	532	1070	1061	-3	-9

4A.1.3 Impacts on Fuel Use and Generation Mix

The Transport FIP for the 2015 ozone NAAQS is expected to result in significant NO<sub>x</sub> emissions reductions. It is also expected to have some impacts to the power sector. While these impacts are relatively small in percentage terms, consideration of these potential impacts is an important component of assessing the relative impact of the regulatory control alternatives. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, and capacity by fuel type for the 2023, 2025 and 2030 IPM model run years with and without the IRA.

As outlined in Table 4A-5 coal consumption remains similar in 2023 between the two baselines. In 2025 and beyond, the baseline with IRA results in lower coal consumption, with the result that the reduction in total coal consumption is lower in the presence of the IRA than in its absence. However, reductions still occur, demonstrating that the policy constraints are binding.

**Table 4A-5. 2023, 2025 and 2030 Projected U.S. Power Sector Coal Use for the Baseline and the Final Rule with and without IRA**

		Million Tons				Percent Change from Baseline	
		Baseline Run + IRA	Final Rule + IRA	Baseline Run	Final Rule	With IRA	Without IRA
Appalachia Interior Waste Coal West Total	2023	121	121	121	121	0%	0%
		96	96	96	96	0%	0%
		4	4	4	4	0%	0%
		381	381	382	382	0%	0%
		602	602	603	603	0%	0%
Appalachia Interior	2025	75	74	80	79	-2%	-2%
		77	77	76	75	0%	-1%

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Waste Coal		4	4	4	4	0%	0%
West		255	244	257	244	-4%	-5%
Total		411	399	417	402	-3%	-4%
Appalachia	2030	32	31	49	47	-2%	-4%
Interior		46	35	51	49	-24%	-3%
Waste Coal		4	4	4	4	0%	0%
West		133	112	170	154	-16%	-10%
Total		214	182	274	254	-15%	-7%

As outlined in Table 4A-6 gas consumption remains similar in 2023 between the two baselines. In 2025 gas consumption is elevated in the scenario with the IRA in place, reflecting greater levels of coal retirements and lower financing costs for new gas technology. In 2030, total gas consumption is lower in the IRA baseline since energy storage and renewables become more cost competitive relative to fossil fuels, and nuclear retirements are lower. The reduced coal dispatch due to the policy results in similar increases in gas consumption under both baselines.

**Table 4A-6. 2023, 2025 and 2030 Projected U.S. Power Sector Natural Gas Use for the Baseline and the Final Rule with and without IRA**

Year	Trillion Cubic Feet				Percent Change from Baseline	
	Baseline Run + IRA	Final Rule + IRA	Baseline Run	Final Rule	With IRA	Without IRA
2023	7.7	7.7	7.7	7.7	0%	0%
2025	9.6	9.8	9.2	9.4	2%	2%
2030	11.4	11.5	12.2	12.4	1%	1%

As outlined in Table 4A-7 and Table 4A-8 coal and gas prices remain similar in 2023 and 2025 between the two baselines. Gas prices reflect the current elevated fuel price environment through 2025, before returning to fundamentals by 2030. Coal prices reflect elevated levels in 2023, before returning to fundamentals by 2025. The result is that through 2025 the two baselines show similar price trends. By 2030, the gas prices in the IRA baseline are lower, since total gas consumption has fallen, reflecting decreased nuclear retirements, increasing renewable penetration, and falling coal dispatch. Increases in gas price as a result of the policy are similar between the two cases.



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**Table 4A-7. 2023, 2025 and 2030 Projected Minemouth and Power Sector Delivered Coal Price (2016\$) for the Baseline and the Final Rule with and without IRA**

		\$/MMBtu				Percent Change from Baseline	
		Baseline Run + IRA	Final Rule + IRA	Baseline Run	Final Rule	With IRA	Without IRA
Minemouth	2023	1.6	1.6	1.6	1.6	0%	0%
Delivered		2.2	2.2	2.2	2.2	0%	0%
Minemouth	2025	1.1	1.1	1.1	1.1	0%	0%
Delivered		1.7	1.7	1.7	1.7	-1%	-1%
Minemouth	2030	1.1	1.1	1.1	1.2	2%	1%
Delivered		1.4	1.4	1.6	1.6	-1%	-2%

**Table 4A-8. 2023, 2025 and 2030 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2016\$) for the Baseline and the Final Rule with and without IRA**

		\$/MMBtu				Percent Change from Baseline	
		Baseline Run + IRA	Final Rule + IRA	Baseline Run	Final Rule	With IRA	Without IRA
Henry Hub	2023	4.8	4.8	4.8	4.8	0%	0%
Delivered		4.9	4.9	4.9	4.9	0%	0%
Henry Hub	2025	3.4	3.4	3.4	3.4	0%	0%
Delivered		3.5	3.5	3.5	3.5	0%	0%
Henry Hub	2030	2.5	2.6	2.7	2.7	1%	0%
Delivered		2.6	2.6	2.8	2.8	1%	0%

As outlined in Table 4A-9 the generation mix remains similar between the two baselines in 2023. By 2025, gas generation rises relative to coal generation, and increases in nuclear generation driven by reduced levels of nuclear retirement. Total non-hydro RE generation is lower, reflecting the fact that in the absence of the IRA the Production Tax Credit (PTC) for shore wind and the Investment Tax Credit (ITC) for solar PV builds are assumed to phase out through 2025. This results in a ‘rush to build’ in order to take advantage of the tax credits before they expire. Under the IRA scenario, the tax credits are both more valuable and extend throughout the forecast period, as such renewable additions accelerate over the forecast period, taking advantage of cost declines that occur later in the horizon. Hence gas generation peaks in 2025 and then declines over the rest of the forecast period under the IRA baseline, while gas generation grows throughout the forecast period under the non-IRA baseline.

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Tightening mass budgets in the 2025 run year (representing the 2026 compliance year in the rule) lead to erosion of coal dispatch under the policy scenario under both cases. In 2030, imposition of the deferred backstop emission rate results in higher levels of coal retirement, driving coal generation lower under both scenarios.

**Table 4A-9. 2023, 2025 and 2030 Projected U.S. Generation by Fuel Type for the Baseline and the Final Rule with and without IRA**

	Year	Generation (TWh)				Percent Change from Baseline	
		Baseline Run + IRA	Final Rule + IRA	Baseline Run	Final Rule	With IRA	Without IRA
Coal	2023	1,131	1,131	1,133	1,133	0%	0%
Natural Gas		1,091	1,091	1,090	1,090	0%	0%
Nuclear		775	775	775	775	0%	0%
Hydro		289	289	289	289	0%	0%
Non-Hydro RE		757	757	756	756	0%	0%
Oil/Gas Steam		27	27	27	27	0%	0%
Other		33	33	33	33	0%	0%
Grand Total		4,103	4,103	4,103	4,103	0%	0%
Coal	2025	777	755	793	765	-3%	-4%
Natural Gas		1,376	1,397	1,311	1,332	1%	2%
Nuclear		747	747	724	724	0%	0%
Hydro		293	293	294	295	0%	0%
Non-Hydro RE		910	912	995	1,002	0%	1%
Oil/Gas Steam		18	18	18	18	0%	-1%
Other		32	32	32	32	0%	0%
Grand Total		4,154	4,154	4,167	4,168	0%	0%
Coal	2030	397	347	523	489	-13%	-7%
Natural Gas		1,635	1,653	1,691	1,710	1%	1%
Nuclear		725	725	611	614	0%	1%
Hydro		305	305	300	300	0%	0%
Non-Hydro RE		1,192	1,224	1,111	1,122	3%	1%
Oil/Gas Steam		12	11	22	22	-6%	0%
Other		32	31	32	32	0%	0%
Grand Total		4,296	4,296	4,289	4,288	0%	0%

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind.

As outlined in Table 4A-10 the capacity mix follows similar trends to those seen under the generation mix table. Coal capacity in 2023 remains identical across cases, reflecting the limitation on retirements. In 2023 gas capacity is higher, reflecting incremental builds as a result of the removal of the carbon uncertainty adder. Non-Hydro RE builds are lower through 2025 under the IRA scenario and then higher thereafter, as described earlier. By 2030 total coal

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retirements as a result of the policy are 14 GW in the absence of IRA, and 17 GW in the presence of IRA. This is driven by the weaker competitive position of fossil fired EGUs under the IRA scenario, making SCR retrofits on existing coal plants less economic. As a result, there are 2.7 GW of SCR retrofits under the Final Rule with IRA scenario as compared to 8 GW of retrofits in the Final Rule scenario without IRA.

**Table 4A-10. 2023, 2025 and 2030 Projected U.S. Capacity by Fuel Type for the Baseline and the Final Rule with and without IRA**

	Year	Capacity (GW)				Percent Change from Baseline run	
		Baseline Run + IRA	Final Rule + IRA	Baseline Run	Final Rule	With IRA	Without IRA
Coal	2023	187	187	187	187	0%	0%
Natural Gas		441	441	441	441	0%	0%
Nuclear		97	97	97	97	0%	0%
Hydro		102	102	102	102	0%	0%
Non-Hydro RE		241	241	241	241	0%	0%
Oil/Gas Steam		73	73	73	73	0%	0%
Other		7	7	7	7	0%	0%
Grand Total		1,163	1,163	1,163	1,163	0%	0%
Coal	2025	138	137	140	138	0%	-1%
Natural Gas		440	441	436	436	0%	0%
Nuclear		93	93	91	91	0%	0%
Hydro		102	102	102	102	0%	0%
Non-Hydro RE		278	278	301	304	0%	1%
Oil/Gas Steam		60	59	60	60	0%	0%
Other		7	7	7	7	0%	0%
Grand Total		1,136	1,136	1,154	1,155	0%	0%
Coal	2030	100	82	112	98	-17%	-13%
Natural Gas		454	458	468	477	1%	2%
Nuclear		91	91	76	76	0%	1%
Hydro		104	104	103	103	0%	0%
Non-Hydro RE		357	365	339	343	2%	1%
Oil/Gas Steam		61	64	62	64	5%	2%
Other		7	7	7	7	0%	0%
Grand Total		1,203	1,204	1,189	1,189	0%	0%

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind

## CHAPTER 5: BENEFITS

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### Overview

The Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 Ozone NAAQS) is expected to reduce emissions of nitrogen oxides (NO<sub>x</sub>) transported from states that contribute significantly to nonattainment or interfere with maintenance of the 2015 Ozone National Ambient Air Quality Standards (NAAQS) in downwind states. Implementing the Transport FIP for the 2015 Ozone NAAQS is expected to reduce emissions of NO<sub>x</sub>, which will in turn reduce concentrations of ground-level ozone and fine particles (PM<sub>2.5</sub>); the rule is also projected to reduce sulfur dioxide (SO<sub>2</sub>), direct PM<sub>2.5</sub> emissions, carbon dioxide (CO<sub>2</sub>) emissions as well as water effluents, and potentially reduce mercury (Hg) emissions. This chapter reports the estimated monetized health benefits from reducing concentrations of ozone and PM<sub>2.5</sub> for each of three regulatory control alternatives described in prior chapters.<sup>122</sup> The chapter also reports the estimated monetized climate benefits from reducing CO<sub>2</sub> emissions. Though the rule is likely to also yield positive benefits associated with reducing pollutants other than ozone and PM<sub>2.5</sub>, limited time, resource and data limitations prevented us from characterizing the value of those reductions.

This chapter describes the methods used to estimate the benefits to human health of reducing concentrations of ozone from affected EGUs (electrical generating units) and non-EGUs (non-electric generating units, or other stationary source emissions sources) and PM<sub>2.5</sub> from affected EGUs. The analysis quantifies health benefits resulting from changes in ozone concentrations in 2023 and changes in ozone and PM<sub>2.5</sub> in 2026 for each of the three regulatory control alternatives (i.e., final rule, less stringent alternative, and more stringent alternative). The methods for quantifying the number and value of air pollution-attributable premature deaths and illnesses are described in the Technical Support Document (TSD) for the 2022 PM NAAQS

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<sup>122</sup> A comprehensive approach to benefit-cost analysis (BCA) is required to assess whether it is conceivable for those who experience a net gain from a regulatory action to potentially compensate those who experience a net loss. As such, a BCA should aim to evaluate all benefits and costs resulting from the regulation, which includes welfare effects from all changes in externalities due to changes in environmental contaminants as well as any other externalities. This requires evaluating changes in pollutant concentrations induced beyond the contaminant(s) targeted by the action.

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Reconsideration Proposal RIA titled *Estimating PM<sub>2.5</sub>- and Ozone-Attributable Health Benefits*<sup>123</sup> (U.S. EPA 2023).

Analyses were also run for each year between 2023 and 2042, using the model surfaces as described below, but accounting for the change in population size in each year, income growth, and baseline mortality incidence rates at five-year increments. However, due to additional uncertainties associated with baseline air quality projections beyond 2026, annual health benefits beyond 2026 presented in Tables 5-7 and 5-8 are based on 2026 air quality changes. Additionally, within each 12 km grid cell we assumed the 2023 ozone concentration change until 2025 and the 2026 ozone and PM<sub>2.5</sub> concentration change until 2042. As we do not account fully for changes in the size or distribution of the population beyond the year 2026, and the changes in the level and location of NO<sub>x</sub> emissions attributable to this rule, this may introduce uncertainty to the analysis and is described below in Section 5.1.3.

Data, resource, and methodological limitations prevent the EPA from monetizing health benefits of reducing direct exposure to NO<sub>2</sub> and SO<sub>2</sub>, ecosystem effects and visibility impairment associated with these pollutants, ozone and PM<sub>2.5</sub>, as well as benefits from reductions in other pollutants, such as water effluents. We qualitatively discuss these unquantified benefits in this chapter.

### 5.1 Estimated Human Health Benefits

The final rule is expected to reduce ozone season and annual NO<sub>x</sub> emissions. In the presence of sunlight, NO<sub>x</sub> and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO<sub>x</sub> emissions generally reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs. In addition to NO<sub>x</sub>, the rule is also expected to reduce emissions of direct PM<sub>2.5</sub> and SO<sub>2</sub> throughout the year. Because NO<sub>x</sub> and SO<sub>2</sub> are also precursors to secondary formation of ambient PM<sub>2.5</sub>, reducing

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<sup>123</sup> The Agency recently asked the Science Advisory Board to evaluate the approach EPA takes to identifying, selecting and parametrizing endpoints to quantify and monetize health benefits; this approach is detailed in a Technical Support Document (TSD) noted above (U.S. EPA, 2023). Additional information regarding the composition of the SAB panel, the schedule for the review and the charge questions may be found at [https://sab.epa.gov/ords/sab/f?p=114:18:11364624237840:::RP,18:P18\\_ID:2617](https://sab.epa.gov/ords/sab/f?p=114:18:11364624237840:::RP,18:P18_ID:2617)

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these emissions would reduce human exposure to ambient PM<sub>2.5</sub> throughout the year and would reduce the incidence of PM<sub>2.5</sub>-attributable health effects.

In this Transport FIP for the 2015 Ozone NAAQS regulatory impact analysis (RIA), as discussed above, the EPA quantifies benefits of changes in ozone and PM<sub>2.5</sub> concentrations. In particular, we incorporate evidence reported in the most recent completed PM and Ozone Integrated Science Assessments (ISAs) and account for recommendations from the Science Advisory Board (U.S. EPA 2019a, U.S. EPA 2020b, U.S. EPA-SAB 2019, U.S. EPA-SAB 2020a). When updating each health endpoint, the EPA considered: (1) the extent to which there exists a causal relationship between that pollutant and the adverse effect; (2) whether suitable epidemiologic studies exist to support quantifying health impacts; (3) and whether robust economic approaches are available for estimating the value of the impact of reducing human exposure to the pollutant. Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized below. Detailed descriptions of these updates are available in the TSD for the 2022 PM NAAQS Reconsideration Proposal RIA titled *Estimating PM<sub>2.5</sub>- and Ozone-Attributable Health Benefits* (U.S. EPA 2023).

The *Estimating PM<sub>2.5</sub>- and Ozone-Attributable Health Benefits* TSD describes fully the Agency's approach for quantifying the number and value of estimated air pollution-related impacts. In this document the reader can find the rationale for selecting health endpoints to quantify; the demographic, health and economic data used; modeling assumptions; and our techniques for quantifying uncertainty.<sup>124</sup>

As structured, the rule would affect the distribution of ozone and PM<sub>2.5</sub> concentrations in much of the U.S.; this includes locations both meeting and exceeding the NAAQS for ozone and particulate matter (PM). This RIA estimates avoided ozone- and PM<sub>2.5</sub>-related health impacts that are distinct from those reported in the RIAs for both ozone and PM NAAQS (U.S. EPA 2012, 2015e). The ozone and PM NAAQS RIAs illustrate, but do not predict, the benefits and costs of strategies that States may choose to enact when implementing a revised NAAQS; these

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<sup>124</sup> The analysis was completed using BenMAP-CE version 1.5.8, which is a variant of the current publicly available version.

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costs and benefits are illustrative and cannot be added to the costs and benefits of policies that prescribe specific emission control measures. This RIA estimates the benefits (and costs) of specific, estimated emissions control measures. As shown and described in Chapter 3, we project most levels of ozone and PM<sub>2.5</sub> to decrease, primarily in and downwind of the states included in this final rule.<sup>125</sup> The ozone and PM-related benefit estimates are based on these modeled changes in summer season average ozone concentrations and changes in average annual PM<sub>2.5</sub> concentrations.

### *5.1.1 Health Impact Assessment for Ozone and PM<sub>2.5</sub>*

The benefits analysis presented in this chapter incorporates science-policy and technical changes that the Agency adopted and documented in the benefits chapter of the RIA accompanying the 2022 PM NAAQS Reconsideration Proposal (U.S. EPA 2022a), based on the 2019 PM ISA (U.S. EPA 2019a), Supplement to the 2019 PM ISA (U.S. EPA 2022b), and 2020 ozone ISA (U.S. EPA, 2020c).

Estimating the health benefits of reductions in ozone and PM<sub>2.5</sub> exposure begins with estimating the change in exposure for each individual and then estimating the change in each individual's risks for those health outcomes affected by exposure. The benefit of the reduction in each health risk is based on the exposed individual's willingness to pay (WTP) for the change in risk, assuming that each outcome is independent of one another. The greater the magnitude of the risk reduction from a given change in concentration, the greater the individual's WTP, all else equal. The social benefit of the change in health risks equals the sum of the individual WTP estimates across all of the affected individuals residing in the U.S.<sup>126</sup> We conduct this analysis by adapting primary research—specifically, air pollution epidemiology studies and economic value studies—from similar contexts. This approach is sometimes referred to as “benefits transfer.” Below we describe the procedure we follow for: (1) selecting air pollution health endpoints to quantify; (2) calculating counts of air pollution effects using a health impact

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<sup>125</sup> In a small number of areas in the northwest, we project ozone to increase slightly compared to the baseline.

<sup>126</sup> This RIA also reports the change in the sum of the risk, or the change in the total incidence, of a health outcome across the population. If the benefit per unit of risk is invariant across individuals, the total expected change in the incidence of the health outcome across the population can be multiplied by the benefit per unit of risk to estimate the social benefit of the total expected change in the incidence of the health outcome.

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function; and (3) specifying the health impact function with concentration-response parameters drawn from the epidemiological literature.

#### 5.1.2 *Selecting Air Pollution Health Endpoints to Quantify*

As a first step in quantifying ozone and PM<sub>2.5</sub>-related human health impacts, the Agency consults the Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Ozone ISA) (U.S. EPA 2020b) and the Integrated Science Assessment and Supplement for Particulate Matter (PM ISA) (U.S. EPA 2019a, U.S. EPA 2022b). These three documents synthesize the toxicological, clinical and epidemiological evidence to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either acute (i.e., hours or days-long) or chronic (i.e., years-long) exposure; for each outcome, the ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship or not likely to be a causal relationship. The Agency estimates the incidence of air pollution effects for those health endpoints above where the ISA has classified them as either causal or likely-to-be-causal.

In brief, the ISA for ozone found short-term (less than one month) exposures to ozone to be causally related to respiratory effects, a “likely to be causal” relationship with metabolic effects and a “suggestive of, but not sufficient to infer, a causal relationship” for central nervous system effects, cardiovascular effects, and total mortality. The ISA reported that long-term exposures (one month or longer) to ozone are “likely to be causal” for respiratory effects including respiratory mortality, and a “suggestive of, but not sufficient to infer, a causal relationship” for cardiovascular effects, reproductive effects, central nervous system effects, metabolic effects, and total mortality. The PM ISA found short-term exposure to PM<sub>2.5</sub> to be causally related to cardiovascular effects and mortality (i.e., premature death), respiratory effects as likely-to-be-causally related, and a suggestive relationship for metabolic effects and nervous system effects. The ISA identified cardiovascular effects and total mortality as being causally related to long-term exposure to PM<sub>2.5</sub>. A likely-to-be-causal relationship was determined between long-term PM<sub>2.5</sub> exposures and respiratory effects, nervous system effects, and cancer effects; and the evidence was suggestive of a causal relationship for male and female reproduction and fertility effects, pregnancy and birth outcomes, and metabolic effects.



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Table 5-1 reports the ozone and PM<sub>2.5</sub>-related human health impacts effects we quantified and those we did not quantify in this RIA. The list of benefit categories not quantified is not exhaustive. And, among the effects quantified, it might not have been possible to quantify completely either the full range of human health impacts or economic values. Section 5.3 and Table 5-14 below report other omitted health and environmental benefits expected from the emissions and water effluent changes as a result of this rule, such as health effects associated with NO<sub>2</sub> and SO<sub>2</sub>, and any welfare effects such as acidification and nutrient enrichment. Specifically, for ozone-related benefits, for EGUs and non-EGUs we conducted a full health benefits analysis that includes premature deaths and illnesses attributable to photochemical modeled changes in summer season average ozone concentrations for the years 2023 and 2026. For PM-related benefits for EGUs, we conducted a full health benefits analysis that includes premature deaths and illnesses attributable to photochemical modeled changes in average PM<sub>2.5</sub> concentrations for the year 2026.

Consistent with economic theory, the WTP for reductions in exposure to environmental hazards will depend on the expected impact of those reductions on human health and other outcomes. All else equal, WTP is expected to be higher when there is stronger evidence of a causal relationship between exposure to the contaminant and changes in a health outcome (McGartland et al., 2017). For example, in the case where there is no evidence of a potential relationship the WTP would be expected to be zero and the effect should be excluded from the analysis. Alternatively, when there is some evidence of a relationship between exposure and the health outcome, but that evidence is insufficient to definitively conclude that there is a causal relationship, individuals may have a positive WTP for a reduction in exposure to that hazard (U.S. EPA-SAB 2020b, Kivi and Shogren, 2010). Lastly, the WTP for reductions in exposure to pollutants with strong evidence of a relationship between exposure and effect are likely positive and larger than for endpoints where evidence is weak, all else equal. Unfortunately, the economic literature currently lacks a settled approach for accounting for how WTP may vary with uncertainty about causal relationships.

Given this challenge, the Agency draws its assessment of the strength of evidence on the relationship between exposure to PM<sub>2.5</sub> or ozone and potential health endpoints from the ISAs that are developed for the NAAQS process as discussed above. The focus on categories

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identified as having a “causal” or “likely to be causal” relationship with the pollutant of interest is to estimate the pollutant-attributable human health benefits in which we are most confident.<sup>127</sup> All else equal, this approach may underestimate the benefits of ozone and PM<sub>2.5</sub> exposure reductions as individuals may be WTP to avoid specific risks where the evidence is insufficient to conclude they are “likely to be caus[ed]” by exposure to these pollutants.<sup>128</sup> At the same time, WTP may be lower for those health outcomes for which causality has not been definitively established. This approach treats relationships with ISA causality determinations of “likely to be causal” as if they were known to be causal, and therefore benefits could be overestimated.

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<sup>127</sup> This decision criterion for selecting health effects to quantify and monetize ozone and PM<sub>2.5</sub> is only applicable to estimating the benefits of exposure of these two pollutants. This is also the approach used for identifying the unquantified benefit categories for criteria pollutants. This decision criterion may not be applicable or suitable for quantifying and monetizing health and ecological effects of other pollutants. The approach used to determine whether there is sufficient evidence of a relationship between an endpoint affected by non-criteria pollutants, and consequently a positive WTP for reductions in those pollutants, for other unquantified benefits described in this chapter can be found in the source documentation for each of these pollutants (see relevant sections below). The conceptual framework for estimating benefits when there is uncertainty in the causal relationship between a hazard and the endpoints it potentially affects described here applies to these other pollutants.

<sup>128</sup> The EPA includes risk estimates for an example health endpoint with a causality determination of “suggestive, but not sufficient to infer” that is associated with a potentially substantial economic value in the quantitative uncertainty characterization (*Estimating PM<sub>2.5</sub>- and Ozone-Attributable Health Benefits* TSD section 6.2.3).

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**Table 5-1. Health Effects of Ambient Ozone and PM<sub>2.5</sub>**

Category	Effect	Effect Quantified	Effect Monetized	More Information	
Premature mortality from exposure to PM <sub>2.5</sub>	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age 65-99 or age 30-99)	✓	✓	PM ISA	
	Infant mortality (age <1)	✓	✓	PM ISA	
	Heart attacks (age > 18)	✓	✓ <sup>1</sup>	PM ISA	
	Hospital admissions—cardiovascular (ages 65-99)	✓	✓	PM ISA	
	Emergency department visits—cardiovascular (age 0-99)	✓	✓	PM ISA	
	Hospital admissions—respiratory (ages 0-18 and 65-99)	✓	✓	PM ISA	
	Emergency room visits—respiratory (all ages)	✓	✓	PM ISA	
	Cardiac arrest (ages 0-99; excludes initial hospital and/or emergency department visits)	✓	✓ <sup>1</sup>	PM ISA	
	Stroke (ages 65-99)	✓	✓ <sup>1</sup>	PM ISA	
	Asthma onset (ages 0-17)	✓	✓	PM ISA	
	Asthma symptoms/exacerbation (6-17)	✓	✓	PM ISA	
	Lung cancer (ages 30-99)	✓	✓	PM ISA	
	Nonfatal morbidity from exposure to PM <sub>2.5</sub>	Allergic rhinitis (hay fever) symptoms (ages 3-17)	✓	✓	PM ISA
		Lost work days (age 18-65)	✓	✓	PM ISA
Minor restricted-activity days (age 18-65)		✓	✓	PM ISA	
Hospital admissions—Alzheimer’s disease (ages 65-99)		✓	✓	PM ISA	
Hospital admissions—Parkinson’s disease (ages 65-99)		✓	✓	PM ISA	
Other cardiovascular effects (e.g., other ages)		—	—	PM ISA <sup>2</sup>	
Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)		—	—	PM ISA <sup>2</sup>	
Other nervous system effects (e.g., autism, cognitive decline, dementia)		—	—	PM ISA <sup>2</sup>	
Metabolic effects (e.g., diabetes)		—	—	PM ISA <sup>2</sup>	
Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)		—	—	PM ISA <sup>2</sup>	
Cancer, mutagenicity, and genotoxicity effects		—	—	PM ISA <sup>2</sup>	
Mortality from exposure to ozone		Premature respiratory mortality based on short-term study estimates (0-99)	✓	✓	Ozone ISA
		Premature respiratory mortality based on long-term study estimates (age 30–99)	✓	✓	Ozone ISA
		Hospital admissions—respiratory (ages 0-99)	✓	✓	Ozone ISA
	Emergency department visits—respiratory (ages 0-99)	✓	✓	Ozone ISA	
	Asthma onset (0-17)	✓	✓	Ozone ISA	
	Asthma symptoms/exacerbation (asthmatics age 2-17)	✓	✓	Ozone ISA	
Nonfatal morbidity from exposure to ozone	Allergic rhinitis (hay fever) symptoms (ages 3-17)	✓	✓	Ozone ISA	
	Minor restricted-activity days (age 18–65)	✓	✓	Ozone ISA	
	School absence days (age 5–17)	✓	✓	Ozone ISA	
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone ISA <sup>2</sup>	
	Metabolic effects (e.g., diabetes)	—	—	Ozone ISA <sup>2</sup>	
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA <sup>2</sup>	

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Cardiovascular and nervous system effects	—	—	Ozone ISA <sup>2</sup>
Reproductive and developmental effects	—	—	Ozone ISA <sup>2</sup>

<sup>1</sup>Valuation estimate excludes initial hospital and/or emergency department visits.

<sup>2</sup>Not quantified due to data availability limitations and/or because current evidence is only suggestive of causality.

### 5.1.1.2 Calculating Counts of Air Pollution Effects Using the Health Impact Function

We use EPA’s Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE) to quantify counts of premature deaths and illnesses attributable to photochemical modeled changes in summer season average ozone concentrations for the years 2023 and 2026 using health impact functions. The program is also used to estimate counts of premature deaths and illnesses attributable to photochemical modeled changes in annual average PM<sub>2.5</sub> concentrations from changes in NO<sub>x</sub>, SO<sub>2</sub> and PM<sub>2.5</sub> emissions for the year 2026.

BenMAP quantifies counts of attributable effects using a health impact function, which combines information regarding the: concentration-response relationship between air quality changes and the risk of a given adverse outcome; population exposed to the air quality change; baseline rate of death or disease in that population; and air pollution concentration to which the population is exposed.

The following provides an example of a health impact function, in this case for PM<sub>2.5</sub> mortality risk. We estimate counts of PM<sub>2.5</sub>-related total deaths (y<sub>ij</sub>) during each year i (i=1,...,I where I is the total number of years analyzed) among adults aged 30 and older (a) in each county in the contiguous U.S. j (j=1,...,J where J is the total number of counties) as

$$y_{ij} = \sum_a y_{ija} = mo_{ija} \times (e^{\beta \Delta C_{ij}} - 1) \times P_{ija}, \quad \text{Eq[1]}$$

where mo<sub>ija</sub> is the baseline all-cause mortality rate for adults aged a=30-99 in county j in year i stratified in 10-year age groups, β is the risk coefficient for all-cause mortality for adults associated with annual average PM<sub>2.5</sub> exposure, C<sub>ij</sub> is the annual mean PM<sub>2.5</sub> concentration in

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county  $j$  in year  $i$ , and  $P_{ija}$  is the number of county adult residents aged  $a=30-99$  in county  $j$  in year  $i$  stratified into 5-year age groups.<sup>129</sup>

The BenMAP-CE tool is pre-loaded with projected population from the Woods & Poole company; cause-specific and age-stratified death rates from the Centers for Disease Control and Prevention, projected to future years; recent-year baseline rates of hospital admissions, emergency department visits and other morbidity outcomes from the Healthcare Cost and Utilization Program and other sources; concentration-response parameters from the published epidemiologic literature cited in the Integrated Science Assessments for fine particles and ground-level ozone; and, cost of illness or willingness to pay economic unit values for each endpoint. Changes in ozone and  $PM_{2.5}$  concentrations are taken from the air pollution spatial surfaces for the analytic years 2023 (ozone only) and 2026 described in Chapter 3.

#### 5.1.1.3 Quantifying Cases of Ozone-Attributable Premature Death

Mortality risk reductions account for the majority of monetized ozone-related and  $PM_{2.5}$ -related benefits. For this reason, this subsection and the following provide a brief background of the scientific assessments that underly the quantification of these mortality risks and identifies the risk studies used to quantify them in this RIA, for ozone and  $PM_{2.5}$  respectively. As noted above, the *Estimating  $PM_{2.5}$ - and Ozone-Attributable Health Benefits* TSD describes fully the Agency’s approach for quantifying the number and value of ozone and  $PM_{2.5}$  air pollution-related impacts, including additional discussion of how the Agency selected the risk studies used to quantify them in this RIA. The TSD also includes additional discussion of the assessments that support quantification of these mortality risk than provide here.

In 2008, the National Academies of Science (NRC 2008) issued a series of recommendations to the EPA regarding the procedure for quantifying and valuing ozone-related mortality due to short-term exposures. Chief among these was that “...short-term exposure to ambient ozone is likely to contribute to premature deaths” and the committee recommended that “ozone-related mortality be included in future estimates of the health benefits of reducing ozone

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<sup>129</sup> In this illustrative example, the air quality is resolved at the county level. For this RIA, we simulate air quality concentrations at 12 by 12 km grids. The BenMAP-CE tool assigns the rates of baseline death and disease stored at the county level to the 12 by 12 km grid cells using an area-weighted algorithm. This approach is described in greater detail in the appendices to the BenMAP-CE user manual.

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exposures...” The NAS also recommended that “...the greatest emphasis be placed on the multicity and [National Mortality and Morbidity Air Pollution Studies (NMMAPS)] ...studies without exclusion of the meta-analyses” (NRC 2008). Prior to the 2015 Ozone NAAQS RIA, the Agency estimated ozone-attributable premature deaths using an NMMAPS-based analysis of total mortality (Bell et al. 2004), two multi-city studies of cardiopulmonary and total mortality (Huang et al. 2004; Schwartz 2005) and effect estimates from three meta-analyses of non-accidental mortality (Bell et al. 2005; Ito et al. 2005; Levy et al. 2005). Beginning with the 2015 Ozone NAAQS RIA, the Agency began quantifying ozone-attributable premature deaths using two newer multi-city studies of non-accidental mortality (Smith et al. 2009; Zanobetti and Schwartz 2008) and one long-term cohort study of respiratory mortality (Jerrett et al. 2009). The 2020 Ozone ISA included changes to the causality relationship determinations between short-term exposures and total mortality, as well as including more recent epidemiologic analyses of long-term exposure effects on respiratory mortality (U.E. EPA, 2020b). As a result, we use two estimates of ozone-attributable respiratory deaths from short-term exposures are estimated using the risk estimate parameters from Zanobetti et al. (2008) and Katsouyanni et al. (2009). Ozone-attributable respiratory deaths from long-term exposures are estimated using Turner et al. (2016). Due to time and resource limitations, we were unable to reflect the warm season defined by Zanobetti et al. (2008) as June-August. Instead, we apply this risk estimate to our standard warm season of May-September.

#### *5.1.1.4 Quantifying Cases of PM<sub>2.5</sub>-Attributable Premature Death*

When quantifying PM-attributable cases of adult mortality, we use the effect coefficients from two epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Turner et al. 2016) and the Medicare cohort (Di et al. 2017). The Integrated Science Assessment for Particulate Matter (PM ISA) (U.S. EPA [20192019a](#)) and Supplement to the 2019 PM ISA (U.S. EPA 2022b) concluded that the analyses of the ACS and Medicare cohorts provide strong evidence of an association between long-term PM<sub>2.5</sub> exposure and premature mortality with support from additional cohort studies. There are distinct attributes of both the ACS and Medicare cohort studies that make them well-suited to being used in a PM benefits assessment and so here we present PM<sub>2.5</sub> related effects derived using relative risk estimates from both cohorts.

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The PM ISA, which was reviewed by the Clean Air Scientific Advisory Committee of EPA’s Science Advisory Board (SAB-CASAC) (EPA-SAB 2020a), concluded that there is a causal relationship between mortality and both long-term and short-term exposure to PM<sub>2.5</sub> based on the entire body of scientific evidence. The PM ISA also concluded that the scientific literature supports the use of a no-threshold log-linear model to portray the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response relationship. The 2019 PM ISA, which informed the setting of the 2020 PM NAAQS, reviewed available studies that examined the potential for a population-level threshold to exist in the concentration-response relationship. Based on such studies, the ISA concluded that the evidence supports the use of a “no-threshold” model and that “little evidence was observed to suggest that a threshold exists” (U.S. EPA 2009) (pp. 2-25 to 2-26). Consistent with this evidence, the Agency historically has estimated health impacts above and below the prevailing NAAQS (U.S. EPA 2010c, 2010d, 2011c, 2011d, 2012, 2013b, 2014a, 2014b, 2014c, 2015a, 2015b, 2015c, 2015d, 2015e, 2016b).

#### 5.1.2 Economic Valuation Methodology for Health Benefits

We next quantify the economic value of the ozone and PM<sub>2.5</sub>-related deaths and illnesses estimated above. Changes in ambient concentrations of air pollution generally yield small changes in the risk of future adverse health effects for a large number of people. The appropriate economic measure of the value of these small changes in risk of a health effect for the purposes of a benefit-cost analysis is WTP. For some health effects, such as hospital admissions, WTP estimates are not generally available, so we use the cost of treating or mitigating the effect. These cost-of-illness (COI) estimates are typically a lower bound estimate of the true value of reducing the risk of a health effect because they reflect the direct expenditures related to treatment, but not the value of avoided pain and suffering. The unit values applied in this analysis are provided in Table 21 of the *Estimating PM<sub>2.5</sub>- and Ozone-Attributable Health Benefits* TSD.

The value of avoided premature deaths generally account for over 95 percent of monetized ozone-related benefits and over 98 percent of monetized PM<sub>2.5</sub>-related benefits. The economics literature concerning the appropriate method for valuing reductions in premature mortality risk is still developing. The value for the projected reduction in the risk of premature

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mortality is the subject of continuing discussion within the economics and public policy analysis community. Following the advice of the SAB’s Environmental Economics Advisory Committee (SAB-EEAC), the EPA currently uses the value of statistical life (VSL) approach in calculating estimates of mortality benefits, because we believe this calculation provides the most reasonable single estimate of an individual’s willingness to trade off money for changes in the risk of death (U.S. EPA-SAB 2000a). The VSL approach is a summary measure for the value of small changes in the risk of death experienced by a large number of people.

The EPA continues work to update its guidance on valuing mortality risk reductions, and the Agency consulted several times with the SAB-EEAC on this issue. Until updated guidance is available, the Agency determined that a single, peer-reviewed estimate applied consistently, best reflects the SAB-EEAC advice it has received. Therefore, EPA applies the VSL that was vetted and endorsed by the SAB in the *Guidelines for Preparing Economic Analyses* (U.S. EPA 2016a) while the Agency continues its efforts to update its guidance on this issue. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is \$4.8 million (1990\$). We then adjust this VSL to account for the currency year and to account for income growth from 1990 to the analysis year. Specifically, the VSL applied in this analysis in 2016\$ after adjusting for income growth is \$10.7 million for 2026.

The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing changes in the risk of premature death and continues to engage with the SAB to identify scientifically sound approaches to update its mortality risk valuation estimates. In 2016, the Agency proposed new meta-analytic approaches for updating its estimates (U.S. EPA-SAB 2017), which were subsequently reviewed by the SAB-EEAC. The EPA is reviewing the SAB’s formal recommendations.

In valuing PM<sub>2.5</sub>-related premature mortality, we discount the value of premature mortality occurring in future years using rates of 3 percent and 7 percent (U.S. Office of Management and Budget 2003). We assume that there is a multi-year “cessation” lag between changes in PM exposures and the total realization of changes in health effects. Although the structure of the lag is uncertain, the EPA follows the advice of the SAB-HES to use a segmented



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lag structure that assumes 30 percent of premature deaths are reduced in the first year, 50 percent over years 2 to 5, and 20 percent over the years 6 to 20 after the reduction in PM<sub>2.5</sub> (U.S. EPA-SAB 2004). Changes in the cessation lag assumptions do not change the total number of estimated deaths but rather the timing of those deaths.

Because estimated counts of short-term ozone-related premature mortality occur within each analysis year, these estimated ozone-related benefits are identical for all discount rates. When valuing changes in long-term ozone-attributable respiratory deaths using the Turner et al. (2015) study, we follow advice provided by the Health Effects Subcommittee of the SAB, which found that “...there is no evidence in the literature to support a different cessation lag between ozone and particulate matter. The HES therefore recommends using the same cessation lag structure and assumptions as for particulate matter when utilizing cohort mortality evidence for ozone” (U.S. EPA-SAB 2010).

These estimated health benefits do not account for the influence of future changes in the climate on ambient concentrations of pollutants (USGCRP 2016). For example, recent research suggests that future changes to climate may create conditions more conducive to forming ozone; the influence of changes in the climate on PM<sub>2.5</sub> concentrations are less clear (Fann et al. 2015). The estimated health benefits also do not consider the potential for climate-induced changes in temperature to modify the relationship between ozone and the risk of premature death (Fann et al. 2021, Jhun et al. 2014; Ren et al. 2008a, 2008b).

### *5.1.3 Characterizing Uncertainty in the Estimated Benefits*

This analysis includes many data sources as inputs that are each subject to uncertainty. Input parameters include projected emission inventories, projected emissions and emissions changes from the electricity planning model, projected baseline emission and emissions reductions from non-EGUs, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). When compounded, even small uncertainties can greatly influence the size of the total quantified benefits.

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Our estimate of the total monetized ozone and PM<sub>2.5</sub>-attributable benefits is based on the EPA's interpretation of the best available scientific literature and methods and supported by the SAB-HES and the National Academies of Science (NRC 2002). Below are key assumptions underlying the estimates for ozone-related premature deaths, followed by key uncertainties associated with estimating the number and value of PM<sub>2.5</sub>-related premature mortality.

The estimated number and value of avoided ozone-attributable deaths are subject to uncertainty. When estimating the economic value of avoided premature mortality from long-term exposure to ozone, we use a 20-year segment lag (as used for PM<sub>2.5</sub>) as there is no alternative empirical estimate of the cessation lag for long-term exposure to ozone. The 20-year segmented lag accounts for the onset of cardiovascular related mortality, an outcome which is not relevant to the long-term respiratory mortality estimated here. We use a log-linear impact function without a threshold in modeling short-term ozone-related mortality. Thus, the estimates include health benefits from reducing ozone in areas with varied concentrations of ozone down to the lowest modeled concentrations. However, we acknowledge reduced confidence in specifying the shape of the concentration-response relationship in the range of  $\leq 40$ ppb and below (2020 Ozone ISA, section 6.2.6).

We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, the PM ISA concluded that “many constituents of PM<sub>2.5</sub> can be linked with multiple health effects, and the evidence is not yet sufficient to allow differentiation of those constituents or sources that are more closely related to specific outcomes” (U.S. EPA 2009).

As noted above, we quantify health impacts of fine particles using a log-linear no-threshold model. Thus, some portion of the air quality and health benefits from the regulatory control alternatives will occur in areas not attaining the ozone or PM NAAQS. Expected changes in the ambient concentrations of both ozone and PM<sub>2.5</sub> pollutants may lead to states changing their NAAQS compliance approaches. However, we do not simulate how states would account for this rule when complying with the NAAQS, which introduces uncertainty in the estimated benefits (and costs).

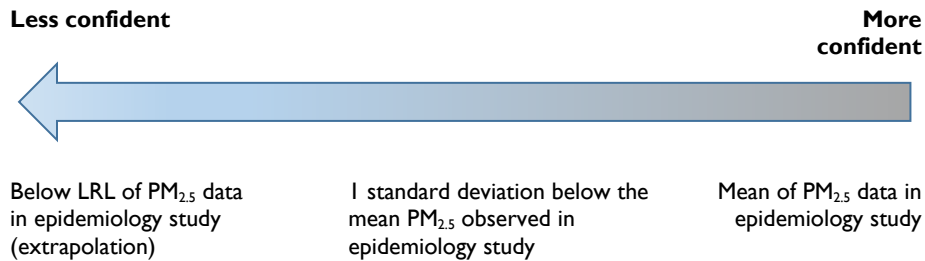
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Also, as noted above, we assume that there is a “cessation” lag between the change in PM exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to PM<sub>2.5</sub> exposures occur in a distributed fashion over the 20 years following exposure based on the advice of the SAB-HES (U.S. EPA-SAB 2004), which affects the valuation of mortality benefits at different discount rates. The above assumptions are subject to uncertainty.

In general, we are more confident in the magnitude of the risks we estimate from simulated PM<sub>2.5</sub> concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated PM<sub>2.5</sub> concentrations that fall below the bulk of the observed data in these studies. There are uncertainties inherent in identifying any particular point at which our confidence in reported associations decreases appreciably, and the scientific evidence provides no clear dividing line. This relationship between the air quality data and our confidence in the estimated risk is represented below in

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[Figure 5-1.](#)



**Figure 5-1. Stylized Relationship between the PM<sub>2.5</sub> Concentrations Considered in Epidemiology Studies and our Confidence in the Estimated PM-related Premature Deaths**

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For Turner et al. 2016, the LRL is 2.8  $\mu\text{g}/\text{m}^3$  and for Di et al. 2017, the LRL is 0.02  $\mu\text{g}/\text{m}^3$ . Additional information on low concentration exposures in Turner et al. 2016 and Di et al. 2017 can be found in section 6.1.2.1 of the *Estimating PM<sub>2.5</sub>- and Ozone-Attributable Health Benefits* TSD. These results are sensitive to the annual mean PM<sub>2.5</sub> concentration the air quality model predicted in each 12 km by 12 km grid cell. The air quality modeling predicts PM<sub>2.5</sub> concentrations to be at or below the current annual mean PM<sub>2.5</sub> NAAQS (12  $\mu\text{g}/\text{m}^3$ ) in nearly all locations. The photochemical modeling we employ accounts for the suite of local, state and federal policies expected to reduce PM<sub>2.5</sub> and PM<sub>2.5</sub> precursor emissions in future years. The results should be viewed in the context of the air quality modeling technique we used to estimate PM<sub>2.5</sub> concentrations. We are more confident in our ability to use the air quality modeling techniques described above to estimate *changes* in annual mean PM<sub>2.5</sub> concentrations than we are in our ability to estimate *absolute* PM<sub>2.5</sub> concentrations.

#### 5.1.4 Estimated Number and Economic Value of Health Benefits

Below we report the estimated number of reduced premature deaths and illnesses in each year relative to the baseline along with the 95% confidence interval (Table 5-2, Table 5-3 and Table 5-4) for ozone-attributable health benefits in 2023 and 2026 and PM-attributable health benefits in 2026. The number of reduced estimated deaths and illnesses from the final rule and more and less stringent alternatives are calculated from the sum of individual reduced mortality and illness risks across the population. Table 5-5 and Table 5-6 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95% confidence interval. We also report the stream of benefits from 2023 through 2042 for the final rule, more-, and less- stringent alternatives, using the monetized sums of long-term ozone and PM<sub>2.5</sub> mortality and morbidity impacts (Table 5-7 and Table 5-8).<sup>130</sup>

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<sup>130</sup> EPA continues to refine its approach for estimating and reporting PM-related effects at lower concentrations. The Agency acknowledges the additional uncertainty associated with effects estimated at these lower levels and seeks to develop quantitative approaches for reflecting this uncertainty in the estimated PM benefits.

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**Table 5-2. Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Final Rule and More and Less Stringent Alternatives for 2023 (95% Confidence Interval)<sup>a,b</sup>**

		Final Rule	More Stringent Alternative	Less Stringent Alternative
<b>Avoided premature respiratory mortalities</b>				
Long-term exposure	Turner <i>et al.</i> (2016) <sup>c</sup>	78 (54 to 100)	80 (56 to 100)	78 (54 to 100)
Short-term exposure	Katsouyanni <i>et al.</i> (2009) <sup>c,d</sup> and Zanobetti <i>et al.</i> (2008) <sup>d</sup> pooled	3.5 (1.4 to 5.6)	3.6 (1.5 to 5.7)	3.5 (1.4 to 5.5)
<b>Morbidity effects</b>				
Long-term exposure	Asthma onset <sup>e</sup>	640 (550 to 720)	650 (560 to 740)	640 (550 to 720)
	Allergic rhinitis symptoms <sup>g</sup>	3,600 (1,900 to 5,200)	3,700 (1,900 to 5,400)	3,600 (1,900 to 5,200)
	Hospital admissions—respiratory <sup>d</sup>	9.3 (-2.4 to 21)	9.6 (-2.5 to 21)	9.3 (-2.4 to 20)
	ED visits—respiratory <sup>f</sup>	200 (54 to 410)	200 (56 to 420)	200 (54 to 410)
Short-term exposure	Asthma symptoms	110,000 (-14,000 to 240,000)	120,000 (-14,000 to 240,000)	110,000 (-14,000 to 240,000)
	Minor restricted-activity days <sup>d,f</sup>	54,000 (22,000 to 85,000)	55,000 (22,000 to 87,000)	54,000 (21,000 to 85,000)
	School absence days	41,000 (-5,800 to 86,000)	42,000 (-5,900 to 88,000)	41,000 (-5,700 to 85,000)

<sup>a</sup> Values rounded to two significant figures.

<sup>b</sup> We estimated ozone benefits for changes in NOx for the ozone season for EGUs in 2023. This table does not include benefits from emissions reductions for non-EGUs because emissions reductions from these sources are not expected prior to 2026 when the final standards would apply to these sources.

<sup>c</sup> Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.

<sup>d</sup> Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).

<sup>e</sup> Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.

<sup>f</sup> Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.

<sup>g</sup> Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

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**Table 5-3. Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Final Rule and More and Less Stringent Alternatives for 2026 (95% Confidence Interval) <sup>a,b</sup>**

Exposure Duration	Study	Affected Facility	Final Rule	More Stringent Alternative	Less Stringent Alternative
			Avoided premature respiratory mortalities		
Long-term exposure	Turner <i>et al.</i> (2016) <sup>c</sup>	EGUs	310 (220 to 400)	560 (380 to 720)	98 (68 to 130)
		Non-EGUs	580 (400 to 750)	890 (620 to 1,200)	220 (160 to 290)
		EGUs + Non-EGUs	890 (620 to 1,200)	1,400 (1,000 to 1,900)	320 (220 to 420)
Short-term exposure	Katsouyanni <i>et al.</i> (2009) <sup>c,d</sup> and Zanobetti <i>et al.</i> (2008) <sup>d</sup> pooled	EGUs	14 (5.7 to 22)	25 (10 to 40)	4.4 (1.8 to 7.0)
		Non-EGUs	26 (11 to 41)	40 (16 to 64)	10 (4.1 to 16)
		EGUs + Non-EGUs	40 (16 to 64)	66 (26 to 100)	15 (5.9 to 23)
<b>Morbidity effects</b>					
Long-term exposure	Asthma onset <sup>e</sup>	EGUs	2,300 (1,900 to 2,600)	4,200 (3,600 to 4,700)	730 (630 to 830)
		Non-EGUs	4,400 (3,800 to 5,000)	6,900 (6,000 to 7,900)	1,800 (1,500 to 2,000)
		EGUs + Non-EGUs	6,600 (5,700 to 7,500)	11,000 (9,500 to 13,000)	2,500 (2,100 to 2,800)
	Allergic rhinitis symptoms <sup>g</sup>	EGUs	13,000 (6,800 to 19,000)	24,000 (13,000 to 35,000)	4,200 (2,200 to 6,100)
		Non-EGUs	25,000 (13,000 to 37,000)	40,000 (21,000 to 58,000)	10,000 (5,300 to 15,000)
		EGUs + Non-EGUs	38,000 (20,000 to 55,000)	64,000 (34,000 to 92,000)	14,000 (7,500 to 21,000)
Short-term exposure	Hospital admissions—respiratory <sup>d</sup>	EGUs	38 (-9.9 to 84)	67 (-17 to 150)	12 (-3.1 to 26)
		Non-EGUs	70 (-18 to 160)	110 (-28 to 240)	27 (-7.0 to 60)
		EGUs + Non-EGUs	110 (-28 to 240)	170 (-46 to 390)	39 (-10 to 86)
Short-term exposure	ED visits—respiratory <sup>f</sup>	EGUs	720 (200 to 1,500)	1,300 (370 to 2,800)	240 (65 to 490)
		Non-EGUs	1,400 (390 to 3,000)	2,200 (610 to 4,600)	560 (150 to 1,200)

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	EGUs + Non-EGUs	2,100 (590 to 4,500)	3,600 (980 to 7,500)	790 (220 to 1,700)
Asthma symptoms		420,000 (-51,000 to 870,000)	770,000 (-95,000 to 1,600,000)	130,000 (-17,000 to 280,000)
	EGUs	810,000 (-100,000 to 1,700,000)	1,300,000 (-160,000 to 2,700,000)	320,000 (-40,000 to 670,000)
	Non-EGUs	1,200,000 (-150,000 to 2,500,000)	2,000,000 (-250,000 to 4,200,000)	460,000 (-56,000 to 950,000)
	EGUs + Non-EGUs	190,000 (77,000 to 300,000)	350,000 (140,000 to 560,000)	62,000 (25,000 to 98,000)
	Non-EGUs	380,000 (150,000 to 590,000)	600,000 (240,000 to 940,000)	150,000 (61,000 to 240,000)
Minor restricted-activity days <sup>d,f</sup>	EGUs + Non-EGUs	570,000 (230,000 to 900,000)	950,000 (380,000 to 1,500,000)	210,000 (85,000 to 340,000)
		150,000 (-21,000 to 310,000)	270,000 (-38,000 to 570,000)	48,000 (-6,700 to 100,000)
	EGUs	290,000 (-41,000 to 600,000)	450,000 (-64,000 to 950,000)	110,000 (-16,000 to 240,000)
School absence days	Non-EGUs	430,000 (-61,000 to 910,000)	720,000 (-100,000 to 1,500,000)	160,000 (-23,000 to 340,000)
	EGUs + Non-EGUs			

<sup>a</sup> Values rounded to two significant figures.

<sup>b</sup> We estimated ozone benefits for changes in NOx for the ozone season and changes in PM<sub>2.5</sub> and PM<sub>2.5</sub> precursors for EGUs in 2026.

<sup>c</sup> Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.

<sup>d</sup> Converted ozone risk estimate metric from MDA1 to MDA8.

<sup>e</sup> Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.

<sup>f</sup> Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.

<sup>g</sup> Converted ozone risk estimate metric from DA24 to MDA8.

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**Table 5-4. Estimated Avoided PM-Related Premature Respiratory Mortalities and Illnesses for the Final Rule and More and Less Stringent Alternatives for 2026 (95% Confidence Interval)**

<b>Avoided Mortality</b>	<b>Final Rule</b>	<b>More Stringent</b>	<b>Less Stringent</b>
Pope III et al., 2019 (adult mortality ages 18-99 years)	440 (320 to 570)	1,400 (1,000 to 1,800)	120 (84 to 150)
Wu et al., 2020 (adult mortality ages 65-99 years)	200 (180 to 230)	640 (570 to 720)	53 (46 to 59)
Woodruff et al., 2008 (infant mortality)	0.64 (-0.40 to 1.6)	1.9 (-1.2 to 4.9)	0.19 (-0.12 to 0.49)
<b>Avoided Morbidity</b>	<b>Final Rule</b>	<b>More Stringent</b>	<b>Less Stringent</b>
Hospital admissions—cardiovascular (age > 18)	29 (21 to 36)	92 (66 to 120)	7.5 (5.4 to 9.5)
Hospital admissions—respiratory	4.7 (0.18 to 9.0)	15 (0.55 to 28)	1.2 (0.047 to 2.4)
ED visits—cardiovascular	64 (-25 to 150)	200 (-78 to 470)	17 (-6.7 to 41)
ED visits—respiratory	130 (26 to 270)	420 (82 to 870)	37 (7.2 to 77)
Acute Myocardial Infarction	6.8 (3.9 to 9.5)	21 (12 to 30)	1.7 (0.97 to 2.4)
Cardiac arrest	3.1 (-1.3 to 7.1)	10 (-4.1 to 23)	0.84 (-0.34 to 1.9)
Hospital admissions—Alzheimer’s Disease	120 (92 to 150)	340 (250 to 420)	32 (24 to 40)
Hospital admissions—Parkinson’s Disease	13 (6.3 to 18)	41 (21 to 60)	3.2 (1.6 to 4.7)
Stroke	12 (3.1 to 21)	39 (10 to 66)	3.2 (0.82 to 5.5)
Lung cancer	14 (4.2 to 23)	44 (13 to 74)	3.6 (1.1 to 6.1)
Hay Fever/Rhinitis	3,300 (790 to 5,700)	10,000 (2,500 to 18,000)	930 (220 to 1,600)
Asthma Onset	520 (490 to 540)	1,600 (1,600 to 1,700)	150 (140 to 150)
Asthma symptoms – Albuterol use	69,000 (-33,000 to 170,000)	220,000 (-110,000 to 530,000)	19,000 (-9,400 to 47,000)
Lost work days	25,000 (21,000 to 28,000)	79,000 (66,000 to 91,000)	6,800 (5,700 to 7,800)
Minor restricted-activity days	140,000 (120,000 to 170,000)	460,000 (380,000 to 550,000)	40,000 (32,000 to 47,000)



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**Table 5-5. 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% Confidence Interval; millions of 2016\$)<sup>a,b</sup>**

Disc. Rate	Pollutant	Final Rule		More Stringent Alternative		Less Stringent Alternative	
3%	Ozone Benefits	\$100 (\$27 to \$220) <sup>c</sup>	and \$820 (\$91 to \$2,100) <sup>d</sup>	\$110 (\$28 to \$230) <sup>c</sup>	and \$840 (\$94 to \$2,200) <sup>d</sup>	\$100 (\$27 to \$220) <sup>c</sup>	and \$810 (\$91 to \$2,100) <sup>d</sup>
7%	Ozone Benefits	\$93 (\$17 to 210) <sup>c</sup>	and \$730 (\$75 to \$1,900) <sup>d</sup>	\$96 (\$18 to \$210) <sup>c</sup>	and \$750 (\$77 to \$2,000) <sup>d</sup>	\$93 (\$17 to \$210) <sup>c</sup>	and \$730 (\$75 to \$1,900) <sup>d</sup>

<sup>a</sup> 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.

<sup>b</sup> We estimated ozone benefits for changes in NOx 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.

<sup>c</sup> Using the pooled short-term ozone exposure mortality risk estimate.

<sup>d</sup> Using the long-term ozone exposure mortality risk estimate.

**Table 5-6. Estimated Discounted Economic Value of Avoided Ozone and PM<sub>2.5</sub>-Attributable Premature Mortality and Illness for the Final Rule and the Less and More Stringent Alternatives in 2026 (95% Confidence Interval; millions of 2016\$)<sup>a,b</sup>**

Disc Rate	Pollutant	Final Rule		More Stringent Alternative		Less Stringent Alternative	
3%	Ozone Benefits	\$1,100 (\$280 to \$2,400)	and \$9,400 (\$1,000 to \$25,000)	\$1,900 (470 to \$4,000)	and \$15,000 (\$1,700 to \$40,000)	\$420 (\$110 to \$900)	and \$3,400 (\$380 to \$8,900)
	PM Benefits	\$2,000 (\$220 to \$5,300)	and \$4,400 (\$430 to \$12,000)	\$6,400 (\$690 to \$17,000)	and \$14,000 (\$1,300 to \$37,000)	\$530 (\$57 to \$1,400)	and \$1,100 (\$110 to \$3,100)
	Ozone plus PM Benefits	\$3,200 (\$500 to \$7,700) <sup>c</sup>	and \$14,000 (\$1,500 to \$36,000) <sup>d</sup>	\$8,300 (\$1,200 to \$21,000) <sup>c</sup>	and \$29,000 (\$3,000 to \$77,000) <sup>d</sup>	\$950 (\$160 to \$2,300) <sup>c</sup>	and \$4,600 (\$490 to \$12,000) <sup>d</sup>
7%	Ozone Benefits	\$1,000 (\$180 to \$2,300)	and \$8,400 (\$850 to \$22,000)	\$1,700 (\$300 to \$3,800)	and \$14,000 (\$1,400 to \$36,000)	\$380 (\$68 to \$850)	and \$3,100 (\$310 to \$8,100)
	PM Benefits	\$1,800 (\$190 to \$4,700)	and \$3,900 (\$380 to \$11,000)	\$5,800 (\$600 to \$15,000)	and \$12,000 (\$1,200 to \$33,000)	470 (\$50 to \$1,200)	and \$1,000 (\$100 to \$2,800)
	Ozone plus PM Benefits	\$2,800 (\$370 to \$7,000) <sup>c</sup>	and \$12,000 (\$1,200 to \$33,000) <sup>d</sup>	\$7,500 (\$910 to \$19,000) <sup>c</sup>	and \$26,000 (\$2,600 to \$69,000) <sup>d</sup>	\$850 (\$120 to \$2,100) <sup>c</sup>	and \$4,100 (\$410 to \$11,000) <sup>d</sup>

<sup>a</sup> 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.

<sup>b</sup> We estimated changes in NOx for the ozone season and annual changes in PM<sub>2.5</sub> and PM<sub>2.5</sub> precursors in 2026.

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<sup>c</sup> Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Wu et al. (2020) long-term PM<sub>2.5</sub> exposure mortality risk estimate.

<sup>d</sup> Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Pope et al. (2016) long-term PM<sub>2.5</sub> exposure mortality risk estimate.

**Table 5-7. Stream of Human Health Benefits from 2023 through 2042: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality for EGUs and Non-EGUs and Long-Term PM<sub>2.5</sub> Mortality for EGUs (Discounted at 3%; millions of 2016\$)<sup>a</sup>**

	Final Rule	More Stringent Alternative	Less Stringent Alternative
2023*	820	840	810
2024	810	840	810
2025	8,600	14,000	3,100
2026*	13,000	27,000	4,200
2027	13,000	26,000	4,200
2028	12,000	25,000	4,000
2029	12,000	25,000	4,000
2030	12,000	25,000	4,000
2031	12,000	25,000	3,900
2032	12,000	25,000	3,900
2033	11,000	24,000	3,800
2034	11,000	24,000	3,800
2035	11,000	24,000	3,700
2036	11,000	24,000	3,700
2037	11,000	23,000	3,700
2038	11,000	23,000	3,600
2039	10,000	22,000	3,500
2040	10,000	22,000	3,500
2041	10,000	22,000	3,400
2042	10,000	21,000	3,400
<b>Net Present Value</b>	<b>200,000</b>	<b>420,000</b>	<b>69,000</b>

\*Year in which air quality models were run. Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: PM<sub>2.5</sub>-attributable deaths (quantified using a concentration-response relationship from the Pope et al. 2016 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2017 study); and ozone and PM<sub>2.5</sub>-related morbidity effects.

<sup>a</sup> For the years 2023-2025, there are no non-EGU emissions reductions. As such, there are no estimated benefits from non-EGU reductions for 2023-2025.

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**Table 5-8. Stream of Human Health Benefits from 2023 through 2042: Monetized Benefits Quantified as Sum of Short-Term Ozone Mortality for EGUs and Non-EGUs and Long-Term PM<sub>2.5</sub> Mortality for EGUs (Discounted at 7%; millions of 2016\$)<sup>a</sup>**

	Final Rule	More Stringent Alternative	Less Stringent Alternative
2023*	730	750	730
2024	700	720	700
2025	7,100	12,000	2,600
2026*	10,000	21,000	3,300
2027	9,700	20,000	3,200
2028	8,900	19,000	2,900
2029	8,500	18,000	2,800
2030	8,200	17,000	2,700
2031	7,800	17,000	2,600
2032	7,500	16,000	2,500
2033	7,000	15,000	2,300
2034	6,700	14,000	2,200
2035	6,400	14,000	2,100
2036	6,100	13,000	2,000
2037	5,800	12,000	1,900
2038	5,400	11,000	1,800
2039	5,100	11,000	1,700
2040	4,900	10,000	1,600
2041	4,600	9,800	1,500
2042	4,400	9,300	1,500
<b>Net Present Value</b>	<b>130,000</b>	<b>260,000</b>	<b>43,000</b>

\*Year in which air quality models were run. Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: PM<sub>2.5</sub>-attributable deaths (quantified using a concentration-response relationship from the Pope et al. 2016 study); Ozone-attributable deaths (quantified using a pooled estimate of results quantified using concentration-response relationships two short-term exposure mortality studies); and ozone and PM<sub>2.5</sub>-related morbidity effects.

<sup>a</sup> For the years 2023-2025, there are no non-EGU emissions reductions. As such, there are no estimated benefits from non-EGU reductions for 2023-2025.

## 5.2 Climate Benefits from Reducing CO<sub>2</sub>

We estimate the climate benefits for this final rulemaking using estimates of the social cost of greenhouse gases (SC-GHG), specifically the social cost of carbon (SC-CO<sub>2</sub>). The SC-CO<sub>2</sub> is the monetary value of the net harm to society associated with a marginal increase in CO<sub>2</sub> emissions in a given year, or the benefit of avoiding that increase. In principle, SC-CO<sub>2</sub> includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-CO<sub>2</sub>, therefore, reflects

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the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO<sub>2</sub> emissions. In practice, data and modeling limitations naturally restrain the ability of SC-CO<sub>2</sub> estimates to include all the important physical, ecological, and economic impacts of climate change, such that the estimates are a partial accounting of climate change impacts and will therefore, tend to be underestimates of the marginal benefits of abatement. The EPA and other Federal agencies began regularly incorporating SC- CO<sub>2</sub> estimates in their benefit-cost analyses conducted under Executive Order (E.O.) 12866<sup>131</sup> since 2008, following a Ninth Circuit Court of Appeals remand of a rule for failing to monetize the benefits of reducing CO<sub>2</sub> emissions in that rulemaking process.

In 2017, the National Academies of Sciences, Engineering, and Medicine published a report that provides a roadmap for how to update SC-GHG estimates used in Federal analyses going forward to ensure that they reflect advances in the scientific literature (National Academies 2017). The National Academies’ report recommended specific criteria for future SC-GHG updates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process. The research community has made considerable progress in developing new data and methods that help to advance various components of the SC-GHG estimation process in response to the National Academies’ recommendations.

In a first-day executive order (E.O. 13990), Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis, President Biden called for a renewed focus on updating estimates of the social cost of greenhouse gases (SC-GHG) to reflect the latest science, noting that “it is essential that agencies capture the full benefits of reducing

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<sup>131</sup> Presidents since the 1970s have issued executive orders requiring agencies to conduct analysis of the economic consequences of regulations as part of the rulemaking development process. E.O. 12866, released in 1993 and still in effect today, requires that for all economically significant regulatory actions, an agency provide an assessment of the potential costs and benefits of the regulatory action, and that this assessment include a quantification of benefits and costs to the extent feasible. Many statutes also require agencies to conduct at least some of the same analyses required under E.O. 12866, such as the Energy Policy and Conservation Act, which mandates the setting of fuel economy regulations. For purposes of this action, monetized climate benefits are presented for purposes of providing a complete benefit-cost analysis under E.O. 12866 and other relevant executive orders. The estimates of change in GHG emissions and the monetized benefits associated with those changes play no part in 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.

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greenhouse gas emissions as accurately as possible.” Important steps have been taken to begin to fulfill this directive of E.O. 13990. In February 2021, the Interagency Working Group on the SC-GHG (IWG) released a technical support document (hereinafter the “February 2021 TSD”) that provided a set of IWG recommended SC-GHG estimates while work on a more comprehensive update is underway to reflect recent scientific advances relevant to SC-GHG estimation (IWG 2021). In addition, as discussed further below, EPA has developed a draft updated SC-GHG methodology within a sensitivity analysis in the regulatory impact analysis of EPA’s November 2022 supplemental proposal for oil and gas standards that is currently undergoing external peer review and a public comment process.<sup>132</sup>

The EPA has applied the IWG’s recommended interim SC-GHG estimates in the Agency’s regulatory benefit-cost analyses published since the release of the February 2021 TSD and is likewise using them in this RIA. We have evaluated the SC-GHG estimates in the February 2021 TSD and have determined that these estimates are appropriate for use in estimating the social benefits of GHG reductions expected to occur as a result of the final rule and alternative standards. These SC-GHG estimates are interim values developed for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available science and economics. After considering the TSD, and the issues and studies discussed therein, the EPA concludes that these estimates, while likely an underestimate, are the best currently available SC-GHG estimates until revised estimates have been developed reflecting the latest, peer-reviewed science.

The SC-GHG estimates presented in the February 2021 SC-GHG TSD and used in this RIA were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices was established to develop estimates relying on the best available science for agencies to use. The IWG published SC-CO<sub>2</sub> estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs

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<sup>132</sup> See <https://www.epa.gov/environmental-economics/scghg>

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were run using a common set of input assumptions in each model for future population, economic, and CO<sub>2</sub> emissions growth, as well as equilibrium climate sensitivity (ECS) – a measure of the globally averaged temperature response to increased atmospheric CO<sub>2</sub> concentrations. These estimates were updated in 2013 based on new versions of each IAM.<sup>133</sup> In August 2016 the IWG published estimates of the social cost of methane (SC-CH<sub>4</sub>) and nitrous oxide (SC-N<sub>2</sub>O) using methodologies that are consistent with the methodology underlying the SC-CO<sub>2</sub> estimates. The modeling approach that extends the IWG SC-CO<sub>2</sub> methodology to non-CO<sub>2</sub> GHGs has undergone multiple stages of peer review. The SC-CH<sub>4</sub> and SC-N<sub>2</sub>O estimates were developed by Marten, Kopits, Griffiths, Newbold, and Wolverton (2015) and underwent a standard double-blind peer review process prior to journal publication. These estimates were applied in regulatory impact analyses of EPA proposed rulemakings with CH<sub>4</sub> and N<sub>2</sub>O emissions impacts.<sup>134</sup> The EPA also sought additional external peer review of technical issues associated with its application to regulatory analysis. Following the completion of the independent external peer review of the application of the Marten et al. (2015) estimates, the EPA began using the estimates in the primary benefit-cost analysis calculations and tables for a number of proposed rulemakings in 2015 (EPA 2015f, 2015g). The EPA considered and responded to public comments received for the proposed rulemakings before using the estimates in final regulatory analyses in 2016.<sup>135</sup> In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-CO<sub>2</sub> estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO<sub>2</sub> estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide* and recommended specific criteria for future updates to the SC-CO<sub>2</sub> estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term

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<sup>133</sup> Dynamic Integrated Climate and Economy (DICE) 2010 (Nordhaus 2010), Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8 (Anthoff and Tol 2013a, 2013b), and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009 (Hope 2013).

<sup>134</sup> The SC-CH<sub>4</sub> and SC-N<sub>2</sub>O estimates were first used in sensitivity analysis for the Proposed Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles–Phase 2 (U.S. EPA, 2015).

<sup>135</sup> See IWG (2016b) for more discussion of the SC-CH<sub>4</sub> and SC-N<sub>2</sub>O and the peer review and public comment processes accompanying their development.

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research needs pertaining to various components of the estimation process (National Academies 2017). Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC-GHG estimates used in regulatory analyses are consistent with the guidance contained in OMB’s Circular A-4, “including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates” (E.O. 13783, Section 5). Benefit-cost analyses following E.O. 13783 used SC-CO<sub>2</sub> estimates that attempted to focus on the specific share of climate change damages in the U.S. as captured by the models (which did not reflect many pathways by which climate impacts affect the welfare of U.S. citizens and residents) and were calculated using two default discount rates recommended by Circular A-4, 3 percent and 7 percent.<sup>136</sup> All other methodological decisions and model versions used in SC-CO<sub>2</sub> calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued Executive Order 13990, which re-established an IWG and directed it to develop an update of the SC-CO<sub>2</sub> estimates that reflect the best available science and the recommendations of the National Academies. In February 2021, the IWG recommended the interim use of the most recent SC- CO<sub>2</sub> estimates developed by the IWG prior to the group being disbanded in 2017, adjusted for inflation (IWG, 2021). As discussed in the February 2021 TSD, the IWG’s selection of these interim estimates reflected the immediate need to have SC- CO<sub>2</sub> estimates available for agencies to use in regulatory benefit-cost analyses and other applications that were developed using a transparent process, peer reviewed methodologies, and the science available at the time of that process.

As noted above, the EPA participated in the IWG but has also independently evaluated the interim SC-CO<sub>2</sub> estimates published in the February 2021 TSD and determined they are appropriate to use to estimate climate benefits for this action. The EPA and other agencies intend to undertake a fuller update of the SC- CO<sub>2</sub> estimates that takes into consideration the advice of

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<sup>136</sup> The EPA regulatory analyses under E.O. 13783 included sensitivity analyses based on global SC-GHG values and using a lower discount rate of 2.5%. OMB Circular A-4 (OMB, 2003) recognizes that special considerations arise when applying discount rates if intergenerational effects are important. In the IWG’s 2015 Response to Comments, OMB—as a co-chair of the IWG—made clear that “Circular A-4 is a living document,” that “the use of 7 percent is not considered appropriate for intergenerational discounting,” and that “[t]here is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself.” OMB, as part of the IWG, similarly repeatedly confirmed that “a focus on global SCC estimates in [regulatory impact analyses] is appropriate” (IWG 2015).

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the National Academies (2017) and other recent scientific literature. The EPA has also evaluated the supporting rationale of the February 2021 TSD, including the studies and methodological issues discussed therein, and concludes that it agrees with the rationale for these estimates presented in the TSD and summarized below.

In particular, the IWG found that the SC-CO<sub>2</sub> estimates used under E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG concluded that those estimates fail to capture many climate impacts that can affect the welfare of U.S. citizens and residents. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Those impacts are better captured within global measures of the social cost of greenhouse gases.

In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. A wide range of scientific and economic experts have emphasized the issue of reciprocity as support for considering global damages of GHG emissions. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to take significant steps to reduce emissions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis—and so benefit the U.S. and its citizens—is for all countries to base their policies on global estimates of damages.

As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, the EPA agrees with this assessment and, therefore, in this RIA, the EPA centers attention on a global measure of SC-CO<sub>2</sub>. This approach is the same as that taken in EPA regulatory analyses over 2009 through 2016. A robust estimate of climate damages only to U.S. citizens and residents that accounts for the myriad of ways that global climate change reduces the net welfare of U.S. populations does not currently exist in the literature. As explained in the February 2021 TSD, existing estimates are both incomplete and an underestimate of total damages that accrue to the citizens and residents of the U.S. because they do not fully capture the regional interactions



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and spillovers discussed above, nor do they include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature, as discussed further below. The EPA, as a member of the IWG, will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of carbon impacts.

Second, the IWG concluded that the use of the social rate of return on capital (7 percent under current OMB Circular A-4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC-CO<sub>2</sub>. Consistent with the findings of the National Academies (2017) and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context (IWG, 2010; IWG, 2013; IWG, 2016a; IWG, 2016b), and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.<sup>137</sup> Furthermore, the damage estimates developed for use in the SC-GHG are estimated in consumption-equivalent terms, and so an application of OMB Circular A-4's guidance for regulatory analysis would then use the consumption discount rate to calculate the SC-GHG. The EPA agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. The EPA also notes that while OMB Circular A-4, as published in 2003, recommends using 3 percent and 7 percent discount rates as "default" values, Circular A-4 also reminds agencies that "different regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions." On discounting, Circular A-4 recognizes that "special ethical considerations arise when comparing benefits and costs across generations," and Circular A-4 acknowledges that analyses may appropriately "discount future costs and

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<sup>137</sup> GHG emissions are stock pollutants, where damages are associated with what has accumulated in the atmosphere over time, and they are long lived such that subsequent damages resulting from emissions today occur over many decades or centuries depending on the specific greenhouse gas under consideration. In calculating the SC-GHG, the stream of future damages to agriculture, human health, and other market and non-market sectors from an additional unit of emissions are estimated in terms of reduced consumption (or consumption equivalents). Then that stream of future damages is discounted to its present value in the year when the additional unit of emissions was released. Given the long time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages.

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consumption benefits...at a lower rate than for intragenerational analysis." In the 2015 Response to Comments on the Social Cost of Carbon for Regulatory Impact Analysis, OMB, EPA, and the other IWG members recognized that "Circular A-4 is a living document" and "the use of 7 percent is not considered appropriate for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." Thus, the EPA concludes that a 7 percent discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this RIA. In this analysis, to calculate the present and annualized values of climate benefits, the EPA uses the same discount rate as the rate used to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 TSD recommends "to ensure internal consistency—i.e., future damages from climate change using the SC-GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate." EPA has also consulted the National Academies' 2017 recommendations on how SC-GHG estimates can "be combined in RIAs with other cost and benefits estimates that may use different discount rates." The National Academies reviewed "several options," including "presenting all discount rate combinations of other costs and benefits with [SC-GHG] estimates."

While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC-GHG estimates, it recommended the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 TSD, the IWG has concluded that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values for use in agency analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the 95<sup>th</sup> percentile of estimates based on a 3 percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change, conditional on the 3 percent estimate of the discount rate. As explained in the February 2021 TSD, this update reflects the immediate need to have an operational SC-GHG

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that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.<sup>138</sup>

Table 5-9 summarizes the interim SC-CO<sub>2</sub> estimates for the years 2020 to 2050. These estimates are reported in 2016 dollars but are otherwise identical to those presented in the IWG’s 2016 TSD (IWG 2016b). For purposes of capturing uncertainty around the SC-CO<sub>2</sub> estimates in analyses, the 2021 TSD emphasizes the importance of considering all four of the SC-CO<sub>2</sub> values. The SC-CO<sub>2</sub> increases over time within the models – i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2025 – because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

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<sup>138</sup> At the time of proposal of this rule, a preliminary injunction was in place that prevented the Agency from displaying the February 2021 TSD-based Interim Estimates. That injunction was subsequently stayed on appeal. The Agency then prepared an addendum to the RIA for the proposed rule presenting the monetized climate benefits of the proposed rule and placed this in the docket and on our website. The EPA invited comment on that analysis. As that document explained, and as remains true for this final rule, “the monetized climate benefits . . . are not a part of the technical or legal basis of the proposed action for which the RIA was prepared.” See Addendum to the Regulatory Impact Analysis: Monetizing Climate Benefits for the Proposed FIP for Addressing Regional Ozone Transport for the 2015 Ozone NAAQS, available at [https://www.epa.gov/system/files/documents/2022-04/2015-fip-climate-benefits-technical-memo\\_04052022.pdf](https://www.epa.gov/system/files/documents/2022-04/2015-fip-climate-benefits-technical-memo_04052022.pdf).

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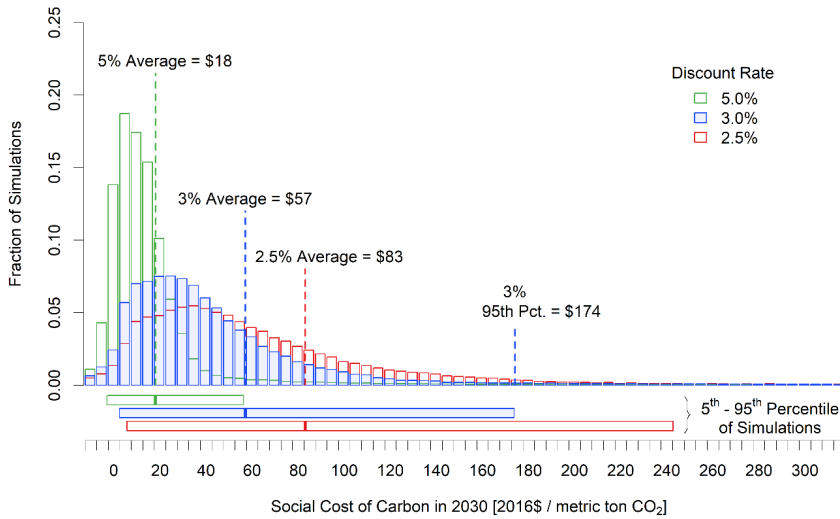
**Table 5-9. Interim Social Cost of Carbon Values, 2020-2050 (2016\$/Metric Tonne CO<sub>2</sub>)**

Emissions Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95 <sup>th</sup> Percentile
2020	\$13	\$47	\$71	\$140
2025	\$15	\$52	\$77	\$160
2030	\$18	\$57	\$83	\$170
2035	\$20	\$63	\$90	\$190
2040	\$23	\$67	\$95	\$210
2045	\$26	\$73	\$100	\$220
2050	\$29	\$78	\$110	\$240

Note: These SC-CO<sub>2</sub> values are identical to those reported in the 2016 TSD (IWG 2016a) adjusted for inflation to 2016 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA 2021). The values are stated in \$/metric tonne CO<sub>2</sub> (1 metric tonne equals 1.102 short tons) and vary depending on the year of CO<sub>2</sub> emissions. This table displays the values rounded to the nearest dollar; the annual unrounded values used in the calculations in this RIA are available on OMB's website: <https://www.whitehouse.gov/omb/information-regulatory-affairs/regulatory-matters/#scghgs>.

Source: Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021)

There are a number of limitations and uncertainties associated with the SC-CO<sub>2</sub> estimates presented in Table 5-9. Some uncertainties are captured within the analysis, while other areas of uncertainty have not yet been quantified in a way that can be modeled. Figure 5-2 [Figure 5-4](#) presents the quantified sources of uncertainty in the form of frequency distributions for the SC-CO<sub>2</sub> estimates for emissions in 2030. The distributions of SC-CO<sub>2</sub> estimates reflect uncertainty in key model parameters such as the equilibrium climate sensitivity, as well as uncertainty in other parameters set by the original model developers. To highlight the difference between the impact of the discount rate and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-CO<sub>2</sub> estimates for each discount rate. As illustrated by the figure, the assumed discount rate plays a critical role in the ultimate estimate of the SC-CO<sub>2</sub>. This is because CO<sub>2</sub> emissions today continue to impact society far out into the future, so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. As discussed in the 2021 TSD, there are other sources of uncertainty that have not yet been quantified and are thus not reflected in these estimates.



**Figure 5-2. Frequency Distribution of SC-CO<sub>2</sub> Estimates for 2030<sup>139</sup>**

The interim SC-CO<sub>2</sub> estimates presented in Table 5-8 have a number of limitations. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower (IWG 2021). Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their “damage functions” – i.e., the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages – lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the

<sup>139</sup> Although the distributions and numbers in Figure 5-2 and Figure 5-4 are based on the full set of model results (150,000 estimates for each discount rate), for display purposes the horizontal axis is truncated with 0.78 percent of the estimates falling below the lowest bin displayed and 3.64 percent of the estimates falling above the highest bin displayed.

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discount rate and uncertainty in economic growth over long time horizons. Likewise, the socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections.

The modeling limitations do not all work in the same direction in terms of their influence on the SC-CO<sub>2</sub> estimates. However, as discussed in the February 2021 TSD, the IWG has recommended that, taken together, the limitations suggest that the SC-CO<sub>2</sub> estimates used in this RIA likely underestimate the damages from CO<sub>2</sub> emissions. EPA concurs that the values used in this RIA conservatively underestimate the rule’s climate benefits. In particular, the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (IPCC 2007), which was the most current IPCC assessment available at the time when the IWG decision over the ECS input was made, concluded that SC-CO<sub>2</sub> estimates “very likely...underestimate the damage costs” due to omitted impacts. Since then, the peer-reviewed literature has continued to support this conclusion, as noted in the IPCC’s Fifth Assessment report and other recent scientific assessments (IPCC 2014) (e.g., IPCC 2018, 2019a, 2019b; U.S. Global Change Research Program (USGCRP) 2016, 2018; and National Academies 2016, 2019). These assessments confirm and strengthen the science, updating projections of future climate change and documenting and attributing ongoing changes. For example, sea level rise projections from the IPCC’s Fourth Assessment report ranged from 18 to 59 centimeters by the 2090s relative to 1980-1999, while excluding any dynamic changes in ice sheets due to the limited understanding of those processes at the time (IPCC 2007). A decade later, the Fourth National Climate Assessment projected a substantially larger sea level rise of 30 to 130 centimeters by the end of the century relative to 2000, while not ruling out even more extreme outcomes (USGCRP 2018). EPA has reviewed and considered the limitations of the models used to estimate the interim SC-GHG estimates and concurs with the February 2021 SC-GHG TSD’s assessment that, taken together, the limitations suggest that the interim SC-GHG estimates likely underestimate the damages from GHG emissions.

The February 2021 TSD briefly previews some of the recent advances in the scientific and economic literature that the IWG is actively following and that could provide guidance on, or methodologies for, addressing some of the limitations with the interim SC-GHG estimates. The IWG is currently working on a comprehensive update of the SC-GHG estimates taking into

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consideration recommendations from the National Academies of Sciences, Engineering and Medicine, recent scientific literature, public comments received on the February 2021 TSD and other input from experts and diverse stakeholder groups (National Academies 2017). While that process continues, the EPA is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward. Most recently, the EPA presented a draft set of updated SC-GHG estimates within a sensitivity analysis in the regulatory impact analysis of the EPA’s November 2022 supplemental proposal for oil and gas standards that aims to incorporate recent advances in the climate science and economics literature. Specifically, the draft updated methodology incorporates new literature and research consistent with the National Academies near-term recommendations on socioeconomic and emissions inputs, climate modeling components, discounting approaches, and treatment of uncertainty, and an enhanced representation of how physical impacts of climate change translate to economic damages in the modeling framework based on the best and readily adaptable damage functions available in the peer reviewed literature. The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, which explains the methodology underlying the new set of estimates, in the docket for the proposed Oil and Gas rule. The EPA is also embarking on an external peer review of this technical report. More information about this process and public comment opportunities is available on the EPA’s website.<sup>140</sup> EPA’s draft technical report will be among the many technical inputs available to the IWG as it continues its work.

Table 5-10 shows the estimated monetary value of the estimated changes in CO<sub>2</sub> emissions expected to occur over 2021-2040 for this rule, the more-stringent alternative, and the less-stringent alternative. The EPA estimated the dollar value of the CO<sub>2</sub>-related effects for each analysis year between 2021 and 2040 by applying the SC-CO<sub>2</sub> estimates, shown in Table 5-9, to the estimated changes in CO<sub>2</sub> emissions in the corresponding year under the regulatory options. The EPA then calculated the present value and annualized benefits from the perspective of 2020

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<sup>140</sup> See <https://www.epa.gov/environmental-economics/scghg>

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by discounting each year-specific value to the year 2020 using the same discount rate used to calculate the SC-CO<sub>2</sub>.<sup>141</sup>

**Table 5-10. Estimated Climate Benefits from Changes in CO<sub>2</sub> Emissions 2023 - 2040 (Millions of 2016\$)<sup>a</sup>**

Regulatory Alternative	Year	Discount Rate and Statistic			
		5% Average	3% Average	2.5% Average	3% 95th Percentile
Final Rule	2023	1	5	7	14
	2024	319	1,075	1,586	3,218
	2025	329	1,096	1,611	3,286
	2026	338	1,117	1,637	3,354
	2030	474	1,512	2,191	4,572
	2035	335	1,015	1,448	3,095

<sup>141</sup> According to OMB’s Circular A-4 (OMB 2003), an “analysis should focus on benefits and costs that accrue to citizens and residents of the United States”, and international effects should be reported, but separately. Circular A-4 also reminds analysts that “[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues.” To correctly assess the total climate damages to U.S. citizens and residents, an analysis should account for all the ways climate impacts affect the welfare of U.S. citizens and residents, including how U.S. GHG mitigation activities affect mitigation activities by other countries, and spillover effects from climate action elsewhere. The SC-GHG estimates used in regulatory analysis under revoked EO 13783 were a limited approximation of some of the U.S. specific climate damages from GHG emissions. These estimates range from \$8 per metric ton CO<sub>2</sub> (2016 dollars) using a 3 percent discount rate for emissions occurring in 2023 to \$9 per metric ton CO<sub>2</sub> using a 3 percent discount rate for emissions occurring in 2040. Applying the same estimate (based on a 3% discount rate) to the CO<sub>2</sub> emissions reduction expected under the finalized option in this final rule would yield benefits from climate impacts within U.S borders of \$0.8 million in 2023, increasing to \$138 million in 2035. However, as discussed at length in the IWG’s February 2021 SC-GHG TSD, these estimates are an underestimate of the benefits of GHG mitigation accruing to U.S. citizens and residents, as well as being subject to a considerable degree of uncertainty due to the manner in which they are derived. In particular, as discussed in this analysis, EPA concurs with the assessment in the February 2021 SC-GHG TSD that the estimates developed under revoked E.O. 13783 did not capture significant regional interactions, spillovers, and other effects and so are incomplete underestimates. As the U.S. Government Accountability Office (GAO) concluded in a June 2020 report examining the SC-GHG estimates developed under E.O. 13783, the models “were not premised or calibrated to provide estimates of the social cost of carbon based on domestic damages” p.29 (U.S. GAO 2020). Further, the report noted that the National Academies found that country-specific social costs of carbon estimates were “limited by existing methodologies, which focus primarily on global estimates and do not model all relevant interactions among regions” p.26 (U.S. GAO 2020). It is also important to note that the SC-GHG estimates developed under E.O. 13783 were never peer reviewed, and when their use in a specific regulatory action was challenged, the U.S. District Court for the Northern District of California determined that use of those values had been “soundly rejected by economists as improper and unsupported by science,” and that the values themselves omitted key damages to U.S. citizens and residents including to supply chains, U.S. assets and companies, and geopolitical security. The Court found that by omitting such impacts, those estimates “fail[ed] to consider...important aspect[s] of the problem” and departed from the “best science available” as reflected in the global estimates. *California v. Bernhardt*, 472 F. Supp. 3d 573, 613-14 (N.D. Cal. 2020). The EPA continues to center attention in this analysis on the global measures of the SC-GHG as the appropriate estimates given the flaws in the U.S. specific estimates, and as necessary for all countries to use to achieve an efficient allocation of resources for emissions reduction on a global basis, and so benefit the U.S. and its citizens.



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**Table 5-10. Estimated Climate Benefits from Changes in CO2 Emissions 2023 - 2040 (Millions of 2016\$)<sup>a</sup>**

Discount Rate and Statistic					
More-Stringent Alternative	2040	474	1,378	1,941	4,234
	2023	1	5	7	14
	2024	605	2,040	3,009	6,104
	2025	623	2,079	3,057	6,234
	2026	642	2,119	3,105	6,363
	2030	150	479	694	1,447
	2035	175	530	757	1,618
	2040	231	671	945	2,062
Less-Stringent Alternative	2023	1	4	6	12
	2024	120	405	598	1,213
	2025	124	413	608	1,239
	2026	128	421	617	1,265
	2030	422	1,346	1,950	4,070
	2035	319	967	1,380	2,949
	2040	471	1,367	1,925	4,200

### 5.3 Total Human Health and Climate Benefits

Tables 5-11 through 5-13 present the total health and climate benefits for the final rule and the more and less stringent alternatives for 2023, 2026, and 2030.

**Table 5-11. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2023 (millions of 2016\$)**

SC-CO <sub>2</sub> Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only <sup>a</sup>
	3%	7%	
Final Rule			
5% (average)	\$100 and \$820	\$94 and \$730	\$1
3% (average)	\$100 and \$820	\$98 and \$740	\$5
2.5% (average)	\$110 and \$820	\$100 and \$740	\$7
3% (95 <sup>th</sup> percentile)	\$110 and \$830	\$110 and \$750	\$14
Less Stringent Alternative			
5% (average)	\$100 and \$810	\$94 and \$730	\$1

**Commented [EO 1286673]:** Why is EPA using 2016\$? Can these be updated to 2022\$?

**Commented [EPA74R73]:** To maintain consistency with the proposal RIA, we presented results throughout the final RIA in 2016\$

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SC-CO <sub>2</sub> Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only <sup>a</sup>
	3%	7%	
3% (average)	\$100 and \$820	\$97 and \$730	\$4
2.5% (average)	\$110 and \$820	\$99 and \$730	\$6
3% (95 <sup>th</sup> percentile)	\$110 and \$830	\$100 and \$740	\$12
More Stringent Alternative			
5% (average)	\$110 and \$840	\$97 and \$750	\$1
3% (average)	\$110 and \$840	\$100 and \$760	\$5
2.5% (average)	\$120 and \$850	\$100 and \$760	\$7
3% (95 <sup>th</sup> percentile)	\$120 and \$850	\$110 and \$770	\$14

<sup>a</sup> Climate benefits are based on changes (reductions) in CO<sub>2</sub> emissions and are calculated using four different estimates of the social cost of carbon (SC-CO<sub>2</sub>) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95<sup>th</sup> percentile at 3 percent discount rate).

**Table 5-12. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2026 (millions of 2016\$)**

SC-CO <sub>2</sub> Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only <sup>a</sup>
	3%	7%	
Final Rule			
5% (average)	\$3,500 and \$14,000	\$3,100 and \$13,000	\$340
3% (average)	\$4,300 and \$15,000	\$3,900 and \$13,000	\$1,100
2.5% (average)	\$4,800 and \$15,000	\$4,400 and \$14,000	\$1,600
3% (95 <sup>th</sup> percentile)	\$6,600 and \$17,000	\$6,200 and \$16,000	\$3,400
Less Stringent Alternative			
5% (average)	\$1,100 and \$4,700	\$980 and \$4,200	\$130
3% (average)	\$1,400 and \$5,000	\$1,300 and \$4,500	\$420
2.5% (average)	\$1,600 and \$5,200	\$1,500 and \$4,700	\$620
3% (95 <sup>th</sup> percentile)	\$2,200 and \$5,800	\$2,100 and \$5,400	\$1,300
More Stringent Alternative			
5% (average)	\$8,900 and \$30,000	\$13,000 and \$27,000	\$640
3% (average)	\$10,000 and \$31,000	\$14,000 and \$28,000	\$2,100
2.5% (average)	\$11,000 and \$32,000	\$15,000 and \$29,000	\$3,100
3% (95 <sup>th</sup> percentile)	\$15,000 and \$35,000	\$18,000 and \$32,000	\$6,400

<sup>a</sup> Climate benefits are based on changes (reductions) in CO<sub>2</sub> emissions and are calculated using four different estimates of the social cost of carbon (SC-CO<sub>2</sub>) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95<sup>th</sup> percentile at 3 percent discount rate).

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**Table 5-13. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2030 (millions of 2016\$)**

SC-CO <sub>2</sub> Discount Rate and Statistic	Health and Climate Benefits (Discount Rate Applied to Health Benefits)		Climate Benefits Only <sup>a</sup>
	3%	7%	
<b>Final Rule</b>			
5% (average)	\$3,900 and \$15,000	\$3,500 and \$14,000	\$470
3% (average)	\$4,900 and \$16,000	\$4,500 and \$15,000	\$1,500
2.5% (average)	\$5,600 and \$17,000	\$5,200 and \$15,000	\$2,200
3% (95 <sup>th</sup> percentile)	\$8,000 and \$19,000	\$7,600 and \$18,000	\$4,600
<b>Less Stringent Alternative</b>			
5% (average)	\$1,400 and \$5,300	\$1,300 and \$4,800	\$420
3% (average)	\$2,300 and \$6,200	\$2,300 and \$5,700	\$1,300
2.5% (average)	\$3,000 and \$6,800	\$2,900 and \$6,300	\$2,000
3% (95 <sup>th</sup> percentile)	\$5,100 and \$8,900	\$5,000 and \$8,400	\$4,100
<b>More Stringent Alternative</b>			
5% (average)	\$9,200 and \$31,000	\$8,300 and \$28,000	\$150
3% (average)	\$9,500 and \$31,000	\$8,600 and \$28,000	\$480
2.5% (average)	\$9,700 and \$32,000	\$8,800 and \$28,000	\$700
3% (95 <sup>th</sup> percentile)	\$10,000 and \$32,000	\$9,500 and \$29,000	\$1,400

<sup>a</sup> Climate benefits are based on changes (reductions) in CO<sub>2</sub> emissions and are calculated using four different estimates of the social cost of carbon (SC-CO<sub>2</sub>) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95<sup>th</sup> percentile at 3 percent discount rate).

#### 5.4 Additional Unquantified Benefits

Data, time, and resource limitations prevented the EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with direct exposure to NO<sub>2</sub> and SO<sub>2</sub> (independent of the role NO<sub>2</sub> and SO<sub>2</sub> play as precursors to ozone and PM<sub>2.5</sub>), as well as ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. While all health benefits and welfare benefits were not able to be quantified, it does not imply that there are not additional benefits associated with reductions in exposures to ozone, PM<sub>2.5</sub>, NO<sub>2</sub> or SO<sub>2</sub>.<sup>142</sup> In this section, we provide a qualitative description of these and water quality benefits, which are listed in Table 5-14.

<sup>142</sup> While not quantified in this RIA, we anticipate that the final rule may produce public health and welfare benefits for populations living in Canada and Mexico.

**Commented [EO 1286675]:** Won't there also be unquantified benefits to other countries, from downwind emissions to Canada, Mexico, and/or Caribbean nations? Suggest adding at least a footnote, if not main text, borrowing language from earlier RIAs: While not quantified in this RIA, we expect the final rule to produce important public health and welfare benefits for populations living in Canada, Mexico, [and other foreign countries.] For example, approximately 90% of the Canadian population lives within 100 miles of the U.S. border, suggesting that some of the air quality improvements projected in areas near the U.S.- Canada border would be enjoyed by Canadian populations as well.

**Commented [EPA76R75]:** Thank you. Footnote added.

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**Table 5-14. Unquantified Health and Welfare Benefits Categories**

Category	Effect	Effect Quantified	Effect Monetized	More Information
Improved Human Health	Asthma hospital admissions	—	—	NO <sub>2</sub> ISA <sup>1</sup>
	Chronic lung disease hospital admissions	—	—	NO <sub>2</sub> ISA <sup>1</sup>
	Respiratory emergency department visits	—	—	NO <sub>2</sub> ISA <sup>1</sup>
Reduced incidence of morbidity from exposure to NO <sub>2</sub>	Asthma exacerbation	—	—	NO <sub>2</sub> ISA <sup>1</sup>
	Acute respiratory symptoms	—	—	NO <sub>2</sub> ISA <sup>1</sup>
	Premature mortality	—	—	NO <sub>2</sub> ISA <sup>1,2,3</sup>
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO <sub>2</sub> ISA <sup>2,3</sup>
Reduced incidence of mortality and morbidity through drinking water from reduced effluent discharges.	Bladder, colon, and rectal cancer from halogenated disinfection byproducts exposure.	—	—	SE ELG BCA <sup>4</sup>
	Reproductive and developmental effects from halogenated disinfection byproducts exposure.	—	—	SE ELG BCA <sup>4</sup>
Reduced incidence of morbidity and mortality from toxics through fish consumption from reduced effluent discharges.	Neurological and cognitive effects to children from lead exposure from fish consumption (including need for specialized education).	—	—	SE ELG BCA <sup>4</sup>
	Possible cardiovascular disease from lead exposure	—	—	SE ELG BCA <sup>4</sup>
	Neurological and cognitive effects from in-utero mercury exposure from maternal fish consumption	—	—	SE ELG BCA <sup>4</sup>
	Skin and gastrointestinal cancer incidence from arsenic exposure	—	—	SE ELG BCA <sup>4</sup>
	Cancer and non-cancer incidence from exposure to toxic pollutants (lead, cadmium, thallium, hexavalent chromium etc.	—	—	SE ELG BCA <sup>4</sup>
Reduced incidence of morbidity and mortality from recreational water exposure from reduced effluent discharges.	Neurological, alopecia, gastrointestinal effects, reproductive and developmental damage from short-term thallium exposure.	—	—	SE ELG BCA <sup>4</sup>
	Cancer and Non-Cancer incidence from exposure to toxic pollutants (methyl-mercury, selenium, and thallium.)	—	—	SE ELG BCA <sup>4</sup>
Improved Environment	Visibility in Class 1 areas	—	—	PM ISA <sup>1</sup>
	Visibility in residential areas	—	—	PM ISA <sup>1</sup>
Reduced effects on materials	Household soiling	—	—	PM ISA <sup>1,2</sup>
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA <sup>2</sup>
Reduced effects from PM deposition (metals and organics)	Effects on individual organisms and ecosystems	—	—	PM ISA <sup>2</sup>
	Visible foliar injury on vegetation	—	—	Ozone ISA <sup>1</sup>
Reduced vegetation and ecosystem effects from exposure to ozone	Reduced vegetation growth and reproduction	—	—	Ozone ISA <sup>1</sup>
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA <sup>1</sup>
	Damage to urban ornamental plants	—	—	Ozone ISA <sup>2</sup>

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Category	Effect	Effect Quantified	Effect Monetized	More Information
Reduced effects from acid deposition	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA <sup>1</sup>
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA <sup>2</sup>
	Other non-use effects			Ozone ISA <sup>2</sup>
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA <sup>2</sup>
	Recreational fishing	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>1</sup>
	Tree mortality and decline	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
	Commercial fishing and forestry effects	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
	Other non-use effects			NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
Reduced effects from nutrient enrichment from deposition.	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
	Coastal and liminal eutrophication	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
	Other non-use effects			NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
Reduced vegetation effects from ambient exposure to SO <sub>2</sub> and NO <sub>x</sub>	Injury to vegetation from SO <sub>2</sub> exposure	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
	Injury to vegetation from NO <sub>x</sub> exposure	—	—	NO <sub>x</sub> SO <sub>x</sub> ISA <sup>2</sup>
Improved water aesthetics from reduced effluent discharges.	Improvements in water clarity, color, odor in residential, commercial and recreational settings.	—	—	SE ELG BCA <sup>4</sup>
	Protection of Threatened and Endangered (T&E) species from changes in habitat and potential population effects.	—	—	SE ELG BCA <sup>4</sup>
Effects on aquatic organisms and other wildlife from reduced effluent discharges	Other non-use effects	—	—	SE ELG BCA <sup>4</sup>
	Changes in sediment contamination on benthic communities and potential for re-entrainment.	—	—	SE ELG BCA <sup>4</sup>
	Quality of recreational fishing and other recreational use values.	—	—	SE ELG BCA <sup>4</sup>
	Commercial fishing yields and harvest quality.	—	—	SE ELG BCA <sup>4</sup>
Reduced water treatment costs from reduced effluent discharges	Reduced drinking, irrigation, and other agricultural use water treatment costs.	—	—	SE ELG BCA <sup>4</sup>
	Increased storage availability in reservoirs	—	—	SE ELG BCA <sup>4</sup>
Reduced sedimentation from effluent discharges	Improved functionality of navigable waterways	—	—	SE ELG BCA <sup>4</sup>
	Decreased cost of dredging	—	—	SE ELG BCA <sup>4</sup>
Benefits of reduced water withdrawal	Benefits from effects aquatic and riparian species from additional water availability.	—	—	SE ELG BCA <sup>4</sup>
	Increased water availability in reservoirs increasing hydropower supply, recreation, and other services.	—	—	SE ELG BCA <sup>4</sup>

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Category	Effect	Effect Quantified	Effect Monetized	More Information
Climate effects	Climate impacts from carbon dioxide (CO <sub>2</sub> )	---	---	Section 5.2 discussion
	Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts)			IPCC, Ozone ISA, PM ISA

<sup>1</sup> We assess these benefits qualitatively due to data and resource limitations for this RIA

<sup>2</sup> We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods

<sup>3</sup> We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association

<sup>4</sup> Benefit and Cost Analysis (BCA) for Revisions to the Effluent Limitations Guidelines (ELG) and Standards for the Steam Electric (SE) Power Generating Point Source Category.

#### 5.4.1 NO<sub>2</sub> Health Benefits

In addition to being a precursor to ozone and PM<sub>2.5</sub>, NO<sub>x</sub> emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health benefits associated with reduced NO<sub>2</sub> exposure in this analysis. Following a comprehensive review of health evidence from epidemiologic and laboratory studies, the Integrated Science Assessment for Oxides of Nitrogen—Health Criteria (NO<sub>x</sub> ISA) (U.S. EPA, 2016c) concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to NO<sub>2</sub>. These epidemiologic and experimental studies encompass a number of endpoints including emergency department visits and hospitalizations, respiratory symptoms, airway hyperresponsiveness, airway inflammation, and lung function. The NO<sub>x</sub> ISA also concluded that the relationship between short-term NO<sub>2</sub> exposure and premature mortality was “suggestive but not sufficient to infer a causal relationship,” because it is difficult to attribute the mortality risk effects to NO<sub>2</sub> alone. Although the NO<sub>x</sub> ISA stated that studies consistently reported a relationship between NO<sub>2</sub> exposure and mortality, the effect was generally smaller than that for other pollutants such as PM.

#### 5.4.2 SO<sub>2</sub> Health Benefits

In addition to being a precursor to PM<sub>2.5</sub>, SO<sub>2</sub> emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health benefits associated with reduced SO<sub>2</sub> in this analysis. Therefore, this analysis only quantifies and monetizes the PM<sub>2.5</sub> benefits associated with the reductions in SO<sub>2</sub> emissions. Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the

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*Integrated Science Assessment for Oxides of Sulfur—Health Criteria* (SO<sub>2</sub> ISA) concluded that there is a causal relationship between respiratory health effects and short-term exposure to SO<sub>2</sub> (U.S. EPA 2017). The immediate effect of SO<sub>2</sub> on the respiratory system in humans is bronchoconstriction. Asthmatics are more sensitive to the effects of SO<sub>2</sub> likely resulting from preexisting inflammation associated with this disease. A clear concentration-response relationship has been demonstrated in laboratory studies following exposures to SO<sub>2</sub> at concentrations between 20 and 100 ppb, both in terms of increasing severity of effect and percentage of asthmatics adversely affected. Based on our review of this information, we identified three short-term morbidity endpoints that the SO<sub>2</sub> ISA identified as a “causal relationship”: asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. The differing evidence and associated strength of the evidence for these different effects is described in detail in the SO<sub>2</sub> ISA. The SO<sub>2</sub> ISA also concluded that the relationship between short-term SO<sub>2</sub> exposure and premature mortality was “suggestive of a causal relationship” because it is difficult to attribute the mortality risk effects to SO<sub>2</sub> alone. Although the SO<sub>2</sub> ISA stated that studies are generally consistent in reporting a relationship between SO<sub>2</sub> exposure and mortality, there was a lack of robustness of the observed associations to adjustment for other pollutants.

#### 5.4.3 Ozone Welfare Benefits

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2020b). Sensitivity to ozone is highly variable across species, with over 65 plant species identified as “ozone-sensitive”, many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services. See Section F of the *Technical Support Document (TSD) for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, Ozone Transport Policy Analysis Proposed Rule TSD* for a summary of an assessment of risk of ozone-related growth impacts on selected forest tree species.

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#### 5.4.4 NO<sub>2</sub> and SO<sub>2</sub> Welfare Benefits

As described in the Integrated Science Assessment (ISA) for Oxides of Nitrogen, Oxides of Sulfur and Particulate Matter Ecological Criteria (NO<sub>x</sub>/SO<sub>x</sub>/PM ISA) (U.S. EPA, 2020d), NO<sub>x</sub> and SO<sub>2</sub> emissions also contribute to a variety of adverse welfare effects, including those associated with acidic deposition, visibility impairment, and nutrient enrichment. Deposition of nitrogen and sulfur causes acidification, which can cause a loss of biodiversity of fishes, zooplankton, and macro invertebrates in aquatic ecosystems, as well as a decline in sensitive tree species, such as red spruce (*Picea rubens*) and sugar maple (*Acer saccharum*) in terrestrial ecosystems. In the northeastern U.S., the surface waters affected by acidification are a source of food for some recreational and subsistence fishermen and for other consumers and support several cultural services, including aesthetic and educational services and recreational fishing. Biological effects of acidification in terrestrial ecosystems are generally linked to aluminum toxicity, which can cause reduced root growth, restricting the ability of the plant to take up water and nutrients. These direct effects can, in turn, increase the sensitivity of these plants to stresses, such as droughts, cold temperatures, insect pests, and disease leading to increased mortality of canopy trees. Terrestrial acidification affects several important ecological services, including declines in habitat for threatened and endangered species (cultural), declines in forest aesthetics (cultural), declines in forest productivity (provisioning), and increases in forest soil erosion and reductions in water retention (cultural and regulating). (U.S. EPA, 2008b)

Deposition of nitrogen is also associated with aquatic and terrestrial nutrient enrichment. In lake and estuarine waters, excess nutrient enrichment can lead to eutrophication. Eutrophication of estuaries can disrupt an important source of food production, particularly fish and shellfish production, and a variety of cultural ecosystem services, including water-based recreational and aesthetic services. Terrestrial nutrient enrichment is associated with changes in the types and number of species and biodiversity in terrestrial systems. Excessive nitrogen deposition upsets the balance between native and nonnative plants, changing the ability of an area to support biodiversity. When the composition of species changes, then fire frequency and intensity can also change, as nonnative grasses fuel more frequent and more intense wildfires. (U.S. EPA, 2008b)



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#### 5.4.5 Visibility Impairment Benefits

Reducing secondary formation of PM<sub>2.5</sub> under the Regional Haze Rule would improve levels of visibility in the U.S. because suspended particles and gases degrade visibility by scattering and absorbing light (U.S. EPA, 2009). Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Visibility has direct significance to people’s enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Particulate sulfate is the dominant source of regional haze in the eastern U.S. and particulate nitrate is an important contributor to light extinction in California and the upper Midwestern U.S., particularly during winter (U.S. EPA, 2009). Previous analyses (U.S. EPA, 2011a) show that visibility benefits can be a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility-related benefits, and we are also unable to determine whether the emissions reductions associated with the final emission guidelines would be likely to have a significant impact on visibility in urban areas or Class I areas.

Reductions in emissions of NO<sub>2</sub> will improve the level of visibility throughout the United States because these gases (and the particles of nitrate and sulfate formed from these gases) impair visibility by scattering and absorbing light (U.S. EPA, 2009). Visibility is also referred to as visual air quality (VAQ), and it directly affects people’s enjoyment of a variety of daily activities (U.S. EPA, 2009). Good visibility increases quality of life where individuals live and work, and where they travel for recreational activities, including sites of unique public value, such as the Great Smoky Mountains National Park (U. S. EPA, 2009).

#### 5.4.6 Water Quality and Availability Benefits

As described in Chapter 4, this rule is expected to lead to shifts in electricity production away from fossil-fired steam generation towards renewable and natural gas generation. There are several negative health, ecological, and productivity effects associated with water effluent and intake from coal generation that will be avoided, and the benefits are qualitatively described

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below.<sup>143</sup> For additional discussion of these effects and their consequent effect on welfare, see the *Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (U.S. EPA 2020a).

#### 5.4.6.1 Potential Water Quality Benefits of Reducing Coal-Fired Power Generation

Discharges of wastewater from coal-fired power plants can contain toxic and bioaccumulative pollutants (e.g., selenium, mercury, arsenic, nickel), halogen compounds (containing bromide, chloride, or iodide), nutrients, and total dissolved solids (TDS), which can cause human health and environmental harm through surface water and fish tissue contamination. Pollutants in coal combustion wastewater are of particular concern because they can occur in large quantities (i.e., total pounds) and at high concentrations in discharges and leachate to groundwater and surface waters. These potential beneficial effects follow directly from reductions in pollutant loadings to receiving waters, and indirectly from other changes in plant operations. The potential benefits come in the form of reduced morbidity, mortality, and on environmental quality and economic activities; reduction in water use, which provides benefits in the form of increased availability of surface water and groundwater; and reductions in the use of surface impoundments to manage Coal Combustion Residual wastes, with benefits in the form of avoided cleanup and other costs associated with impoundment releases.

Reducing coal-fired power generation affects human health risk by changing exposure to pollutants in water via two principal exposure pathways: (1) treated water sourced from surface waters affected by coal-fired power plant discharges and (2) fish and shellfish taken from waterways affected by coal-fired power plant discharges. The human health benefits from surface water quality improvements may include drinking water benefits, fish consumption benefits, and other complimentary measures.

In addition, reducing coal-fired power generation can affect the ecological condition and recreation use effects from surface water quality changes. The EPA expects the ecological impacts from reducing coal-fired power plant discharges could include habitat changes for fresh-

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<sup>143</sup> While natural gas combined cycle units also emit wastewater effluents and withdrawal demands, which offset some of the benefits of reduced fossil steam generation, the scale of these waste streams is much smaller than for other fossil steam generator types.

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and saltwater plants, invertebrates, fish, and amphibians, as well as terrestrial wildlife and birds that prey on aquatic organisms exposed to pollutants from coal combustion. The change in pollutant loadings has the potential to result in changes in ecosystem productivity in waterways and the health of resident species, including threatened and endangered (T&E) species. Loadings from coal-fired power generation have the potential to impact the general health of fish and invertebrate populations, their propagation to waters, and fisheries for both commercial and recreational purposes. Changes in water quality also have the potential to impact recreational activities such as swimming, boating, fishing, and water skiing.

Potential economic productivity effects may stem from changes in the quality of public drinking water supplies and irrigation water; changes in sediment deposition in reservoirs and navigational waterways; and changes in tourism, commercial fish harvests, and property values.

#### *5.4.6.2 Drinking Water*

Pollutants discharged by coal-fired power plants to surface waters may affect the quality of water used for public drinking supplies. In turn these impacts to public water supplies have the potential to affect the costs of drinking water treatment (e.g., filtration and chemical treatment) by changing eutrophication levels and pollutant concentrations in source waters. Eutrophication is one of the main causes of taste and odor impairment in drinking water, which has a major negative impact on public perceptions of drinking water safety. Additional treatment to address foul tastes and odors to bring the finished water into compliance with EPA's National Secondary Drinking Water Treatment Standards can significantly increase the cost of public water supply. Likewise, public drinking water supplies are subject to National Primary Drinking Water Standards that have set legally enforceable maximum contaminant levels (MCLs), for a number of pollutants, like metals, discharged from coal-fired power plants. Drinking water systems downstream from these power plants may be required to treat source water to remove the contaminants to levels below the MCL in the finished water. This treatment will also increase costs at drinking water treatment plants. Episodic releases from coal fired power plants, may be detected only after the completion of a several-month round of compliance monitoring at drinking water treatment plants and there could also be a lag between detection of changes in source water contaminants and the system implementing treatment to address the issue. This lag

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may result in consumers being exposed to these contaminants through ingestion, inhalation, and skin absorption. The constituents found in the power plant discharge may also interact with drinking water treatment processes and contribute to the formation of disinfection byproducts that can have adverse human health impacts.

#### 5.4.6.3 Fish Consumption

Recreational and subsistence fishers (and their household members) who consume fish caught in the reaches downstream of coal-fired power plants may be affected by changes in pollutant concentrations in fish tissue. See the *Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (U.S. EPA 2020a) for a demonstration of the changes in risk to human health from exposure to contaminated fish tissue. This document describes the neurological effects to children ages 0 to 7 from exposure to lead; the neurological effects to infants from in-utero exposure to mercury; the incidence of skin cancer from exposure to arsenic; and the reduced risk of other cancer and non-cancer toxic effects.

#### 5.4.6.4 Changes in Surface Water Quality

Reducing coal-fired power plant discharges may affect the value of ecosystem services provided by surface waters through changes in the habitats or ecosystems (aquatic and terrestrial). Society values changes in ecosystem services by a number of mechanisms, including increased frequency of use and improved quality of the habitat for recreational activities (e.g., fishing, swimming, and boating). Individuals also value the protection of habitats and species that may reside in waters that receive water discharges from coal-plants, even when those individuals do not use or anticipate future use of such waters for recreational or other purposes, resulting in nonuse values.

#### 5.4.6.5 Impacts on Threatened and Endangered Species

For T&E species, even minor changes to reproductive rates and mortality levels may represent a substantial portion of annual population variation. Therefore, changing the discharge of coal-fired power plant pollutants to aquatic habitats has the potential to impact the survivability of some T&E species living in these habitats. The economic value for these T&E

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species primarily comes from the nonuse values people hold for the survivorship of both individual organisms and species survival.

#### *5.4.6.6 Changes in Sediment Contamination*

Water effluent discharges from coal-fired power plants can also contaminate waterbody sediments. For example, sediment adsorption of arsenic, selenium, and other pollutants found in water discharges can result in accumulation of contaminated sediment on stream and lake beds, posing a particular threat to benthic (i.e., bottom-dwelling) organisms. These pollutants can later be re-released into the water column and enter organisms at different trophic levels. Concentrations of selenium and other pollutants in fish tissue of organisms of lower trophic levels can bio-magnify through higher trophic levels, posing a threat to the food chain at large (Ruhl et al., 2012).

#### *5.4.6.7 Reservoir Capacity and Sedimentation Changes in Navigational Waterways*

Reservoirs serve many functions, including storage of drinking and irrigation water supplies, flood control, hydropower supply, and recreation. Streams can carry sediment into reservoirs, where it can settle and cause buildup of sediment layers over time, reducing reservoir capacity (Graf et al., 2010, 2011) and the useful life of reservoirs unless measures such as dredging are taken to reclaim capacity (Hargrove et al., 2010; Miranda, 2017). Likewise, navigable waterways, including rivers, lakes, bays, shipping channels and harbors, are prone to reduced functionality due to sediment build-up, which can reduce the navigable depth and width of the waterway (Clark et al., 1985; Ribaud and Johansson, 2006). For many navigable waters, periodic dredging is necessary to remove sediment and keep them passable. Dredging of reservoirs and navigable waterways can be costly. The EPA expects that changes in suspended solids effluent discharge from coal-fired power plants could reduce sediment loadings to surface waters decreasing reservoir and navigable waterway maintenance costs by changing the frequency or volume of dredging activity.

#### *5.4.6.8 Changes in Water Consumption and Withdrawals*

A reduction in water consumption from coal fired power plants may benefit aquatic and riparian species downstream of the power plant intake through the provision of additional water

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resources in the face of drying conditions and increased rainfall variability. In a study completed, in 2011, by the U.S. Department of Energy's National Renewable Energy Laboratory (U.S. DOE 2011), water consumption, which is defined as water removed from the immediate water environment and can include cooling water evaporation, cleaning, and process related water use including flue gas desulfurization, was found to range from 100 – 1,100 gal/MWh at generic coal power plants. This study also found that water withdraws, defined as the amount of water removed from the ground or diverted from a water source for use, ranged from 300 – 50,000 gal/MWh at a generic coal power plant. Reductions in water consumption and withdraws will lower the number of aquatic organisms impinged and entrained by the power plant's water filtration and cooling systems.

#### 5.4.7 Hazardous Air Pollutant Impacts

The rule is expected to reduce fossil-fired EGU generation and consequentially is expected to lead to reduced HAP emissions. HAP emissions from EGUs create risks of premature mortality from heart attacks, cancer, and neurodevelopmental delays in children, and detrimentally affect economically vital ecosystems used for recreational and commercial purposes. Further, these public health effects are particularly pronounced for certain segments of the American population that are especially vulnerable (e.g., subsistence fishers and their children) to impacts from EGU HAP emissions.

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## CHAPTER 6: ECONOMIC IMPACTS

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### Overview

Economic impact analyses focus on changes in market prices and output levels. If changes in market prices and output levels in the primary markets are significant enough, impacts on other markets may also be examined. Both the magnitude of costs needed to comply with a rule and the distribution of these costs among affected facilities can have a role in determining how the market will change in response to a rule. This chapter analyzes the potential impacts on small entities and the potential labor impacts associated with this rulemaking. For additional discussion of impacts on fuel use and electricity prices, see Chapter 4, Section 4.5.1

### 6.1 Small Entity Analysis

For the final rule, the EPA performed a small entity screening analysis for impacts on all affected EGUs and non-EGU facilities by comparing compliance costs to historic revenues at the ultimate parent company level. This is known as the cost-to-revenue or cost-to-sales test, or the “sales test.” The sales test is an impact methodology the EPA employs in analyzing entity impacts as opposed to a “profits test,” in which annualized compliance costs are calculated as a share of profits. The sales test is frequently used because revenues or sales data are commonly available for entities impacted by the EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Also, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by the EPA on compliance with the Regulatory Flexibility Act (RFA)<sup>144</sup> and is consistent with guidance published by the U.S. Small Business Administration’s (SBA) Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (SBA, 2017).

#### 6.1.1 EGU Small Entity Analysis and Results

This section presents the methodology and results for estimating the impact of the rule on small EGU entities in 2026 based on the following endpoints:

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<sup>144</sup> The RFA compliance guidance to the EPA rule writers can be found at  
<<https://www.epa.gov/sites/production/files/2015-06/documents/guidance-regflexact.pdf>>

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- annual economic impacts of the rule on small entities, and
- ratio of small entity impacts to revenues from electricity generation.

In this analysis, the EPA considered EGUs that are subject to the FIP and meet the following five criteria: 1) EGU is represented in NEEDS v6; 2) EGU is fossil fuel-fired; 3) EGU is located in a state covered by this rule; 4) EGU is neither a cogeneration unit nor solid waste incineration unit; and 5) EGU capacity is 25 Megawatt (MW) or larger. EPA next refined this list of EGUs, narrowing it to those that exhibit at least one of the following changes, in comparison to the baseline. Please see Chapter 4, Section 4.3 for more discussion of the power sector modeling.

- Summer fuel use (BTUs) changes by +/- 1 percent or more
- Summer generation (GWh) changes by +/- 1 percent or more
- NOx summer emissions (tons) changes by +/- 1 percent or more

Based on these criteria, the EPA identified a total of 436 potentially affected EGUs warranting examination in 2026 in this RFA analysis. Next, we determined power plant ownership information, including the name of associated owning entities, ownership shares, and each entity's type of ownership. We primarily used data from Ventyx, supplemented by limited research using publicly available data.<sup>145</sup> Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.<sup>146</sup> These ownership types are:

1. **Investor-Owned Utility (IOU):** Investor-owned assets (e.g., a marketer, independent power producer, financial entity) and electric companies owned by stockholders, etc.
2. **Cooperative (Co-Op):** Non-profit, customer-owned electric companies that generate and/or distribute electric power.
3. **Municipal:** A municipal utility, responsible for power supply and distribution in a small region, such as a city.
4. **Sub-division:** Political subdivision utility is a county, municipality, school district, hospital district, or any other political subdivision that is not classified as a municipality under state law.

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<sup>145</sup> The Ventyx Energy Velocity Suite database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: [www.ventyx.com](http://www.ventyx.com).

<sup>146</sup> Throughout this analysis, EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.

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5. **Private:** Similar to an investor-owned utility, however, ownership shares are not openly traded on the stock markets.
6. **State:** Utility owned by the state.
7. **Federal:** Utility owned by the federal government.

Next, the EPA used both the D&B Hoover’s online database and the Ventyx database to identify the ultimate owners of power plant owners identified in the Ventyx database. This was necessary, as many majority owners of power plants (listed in Ventyx) are themselves owned by other ultimate parent entities (listed in D&B Hoover’s).<sup>147</sup> In these cases, the ultimate parent entity was identified via D&B Hoover’s, whether domestically or internationally owned.

The EPA followed SBA size standards to determine which non-government ultimate parent entities should be considered small entities in this analysis. These SBA size standards are specific to each industry, each having a threshold level of either employees, revenue, or assets below which an entity is considered small.<sup>148</sup> SBA guidelines list all industries, along with their associated North American Industry Classification System (NAICS) code<sup>149</sup> and SBA size standard. Therefore, it was necessary to identify the specific NAICS code associated with each ultimate parent entity to understand the appropriate size standard to apply. Data from D&B Hoover’s was used to identify the NAICS codes for most of the ultimate parent entities. In many cases, an entity that is a majority owner of a power plant is itself owned by an ultimate parent entity with a primary business other than electric power generation. Therefore, it was necessary to consider SBA entity size guidelines for the range of NAICS codes listed in Table 6-1. This table represents the range of NAICS codes and areas of primary business of ultimate parent entities that are majority owners of potentially affected EGUs in EPA’s IPM base case.

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<sup>147</sup> The D&B Hoover’s online platform includes company records that can contain NAICS codes, number of employees, revenues, and assets. For more information, see: <https://www.dnb.com/products/marketing-sales/dnb-hoovers.html>.

<sup>148</sup> SBA’s table of size standards can be located here: <https://www.sba.gov/document/support--table-size-standards>.

<sup>149</sup> North American Industry Classification System can be accessed at the following link: <https://www.census.gov/naics/>

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**Table 6-1. SBA Size Standards by NAICS Code**

NAICS Codes	NAICS U.S. Industry Title	Size Standards (Millions of dollars)	Size Standards (Number of employees)
221111	Hydroelectric Power Generation		500
221112	Fossil Fuel Electric Power Generation		750
221113	Nuclear Electric Power Generation		750
221114	Solar Electric Power Generation		250
221115	Wind Electric Power Generation		250
221116	Geothermal Electric Power Generation		250
221117	Biomass Electric Power Generation		250
221118	Other Electric Power Generation		250
221121	Electric Bulk Power Transmission and Control		500
221122	Electric Power Distribution		1,000
221210	Natural Gas Distribution		1,000
221310	Water Supply and Irrigation Systems	\$41.0	
221320	Sewage Treatment Facilities	\$35.0	
221330	Steam and Air-Conditioning Supply	\$30.0	

Note: Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective December 19, 2022. Available at the following link: <https://www.sba.gov/document/support--table-size-standards>). Source: SBA, 2022

The EPA compared the relevant entity size criterion for each ultimate parent entity to the SBA size standard noted in Table 6-1. We used the following data sources and methodology to estimate the relevant size criterion values for each ultimate parent entity:

1. **Employment, Revenue, and Assets:** EPA used the D&B Hoover’s database as the primary source for information on ultimate parent entity employee numbers, revenue, and assets.<sup>150</sup> In parallel, EPA also considered estimated revenues from affected EGUs based on analysis of IPM parsed file<sup>151</sup> estimates for the baseline run for 2023 and 2026. EPA assumed that the ultimate parent entity revenue was the larger of the two revenue estimates. In limited instances, supplemental research was also conducted to estimate an ultimate parent entity’s number of employees, revenue, or assets.
2. **Population:** Municipal entities are defined as small if they serve populations of less than 50,000.<sup>152</sup> EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination.

<sup>150</sup> Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.

<sup>151</sup> IPM output files report aggregated results for "model" plants (i.e., aggregates of generating units with similar operating characteristics). Parsed files approximate the IPM results at the generating unit level.

<sup>152</sup> The Regulatory Flexibility Act defines a small government jurisdiction as the government of a city, county,

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Ultimate parent entities for which the relevant measure is less than the SBA size standard were identified as small entities and carried forward in this analysis.

In 2026, EPA identified 436 potentially affected EGUs, owned by 75 entities. Of these, the EPA identified 71 potentially affected EGUs owned by 19 small entities included in the power sector baseline.

In 2023, an entity can comply with the Final Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS) through some combination of the following: optimizing existing SCRs, optimizing existing SNCR controls, installing state-of-the-art combustion controls, using allocated allowances, purchasing allowances, or reducing emissions through a reduction in generation. Additionally, units with more allowances than needed can sell these allowances in the market. The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units. In addition to the 2023 compliance options, in 2026 an entity can comply with the Transport FIP for the 2015 ozone NAAQS by installing SCR or SNCR retrofits.

To attempt to account for each potential control strategy, EPA estimates compliance costs as follows:

$$C_{Compliance} = \Delta C_{Operating+Retrofit} + \Delta C_{Fuel} + \Delta C_{Allowances} + \Delta C_{Transaction} + \Delta R$$

where  $C$  represents a component of cost as labeled<sup>153</sup>, and  $\Delta R$  represents the change in revenues, calculated as the difference in value of electricity generation between the baseline case and the rule in in 2026.

Realistically, compliance choices and market conditions can combine such that an entity may actually experience a reduction in any of the individual components of cost. Under the rule, some units will forgo some level of electricity generation (and thus revenues) to comply, and this impact will be lessened on these entities by the projected increase in electricity prices under the

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town, township, village, school district, or special district with a population of less than 50,000 (5 U.S.C. section 601(5)). For the purposes of the RFA, States and tribal governments are not considered small governments. EPA's *Final Guidance for EPA Rulewriters: Regulatory Flexibility Act* is located here: <https://www.epa.gov/sites/default/files/2015-06/documents/guidance-regflexact.pdf>.

<sup>153</sup> Retrofit costs include the costs of fully operating existing controls, as well as the installation of state-of-the-art combustion controls, SCRs and SNCRs.



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rule. On the other hand, those units increasing generation levels will see an increase in electricity revenues and as a result, lower net compliance costs. If entities are able to increase revenue more than an increase in fuel cost and other operating costs, ultimately, they will have negative net compliance costs (or increased profit). Overall, small entities are not projected to install relatively costly emissions control retrofits if it can be avoided while still complying with the rule but may choose to do so in some instances. Because this analysis evaluates the total costs along each of the compliance strategies laid out above for each entity, it inevitably captures gains such as those described. As a result, what we describe as cost is actually a measure of the net economic impact of the rule on small entities.

For this analysis, the EPA used IPM-parsed output to estimate costs based on the parameters above, at the unit level. These impacts were then summed for each small entity, adjusting for ownership share. Net impact estimates were based on the following: operating and retrofit costs, sale or purchase of allowances, and the change in fuel costs or electricity generation revenues under the Transport FIP for the 2015 ozone NAAQS relative to the base case. These individual components of compliance costs were estimated as follows:

- (1) **Operating and retrofit costs** ( $\Delta C_{Operating+Retrofit}$ ): Using engineering analytics, EPA identified which compliance option would be selected by each EGU in 2023 (i.e., SCR/SNCR optimization and/or installing state-of-the-art combustion controls) and applied the appropriate cost to this choice (for details, please see Chapter 4 of this RIA). For 2026, IPM projected retrofit costs were also included in the calculation.
- (2) **Sale or purchase of allowances** ( $\Delta C_{Allowances}$ ): To estimate the value of allowance holdings, allocated allowances were subtracted from projected emissions, and the difference was then multiplied by model projected allowance costs. Units were assumed to purchase or sell allowances to exactly cover their projected emissions under the Transport FIP for the 2015 ozone NAAQS.
- (3) **Fuel costs** ( $\Delta C_{Fuel}$ ): The change in fuel expenditures under the Transport FIP for the 2015 ozone NAAQS was estimated by taking the difference in projected fuel expenditures between the IPM estimates for the Transport FIP for the 2015 ozone NAAQS and the baseline.

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- (4) **Value of electricity generated:** To estimate the value of electricity generated, the projected level of electricity generation is multiplied by the regional-adjusted retail electricity price (\$/MWh) estimate, for all entities except those categorized as private in Ventyx. See Chapter 4, Section 4.5.3 for a discussion of the Retail Price Model, which was used to estimate the change in the retail price of electricity. For private entities, EPA used the wholesale electricity price instead of the retail electricity price because most of the private entities are independent power producers (IPP). IPPs sell their electricity to wholesale purchasers and do not own transmission facilities. Thus, their revenue was estimated with wholesale electricity prices.
- (5) **Administrative costs ( $\Delta C_{Transaction}$ ):** Because most affected units are already monitored as a result of other regulatory requirements, EPA considered the primary administrative cost to be transaction costs related to purchasing or selling allowances. EPA assumed that transaction costs were equal to 1.5 percent of the total absolute value of the difference between a unit’s allocation and projected NOx emissions. This assumption is based on market research by ICF.

As indicated above, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by the EPA on compliance with the RFA and is consistent with guidance published by the SBA’s Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities. The potential impacts, including compliance costs, of the Transport FIP for the 2015 ozone NAAQS on small entities are summarized in Table 6-2. All costs are presented in 2016\$. EPA estimated the annual net compliance cost to small entities to be approximately \$18 million in 2026.

**Table 6-2. Projected Impact of the Transport FIP for the 2015 Ozone NAAQS on Small Entities in 2026**

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost (\$2016 millions)	Number of Small Entities with Compliance Costs >1% of Generation Revenues
Municipal	6	1.0	0
Private	5	0.5	0
Co-op	8	16.6	0
<b>Total</b>	<b>19</b>	<b>18.1</b>	<b>0</b>

Source: IPM analysis

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The EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Of the 19 entities considered in this analysis, none are projected to experience compliance costs greater than 1% of generation revenues in 2026.

6.1.2 Non-EGU Small Entity Impacts and Results

We identified 1,228 emissions units, discussed in Chapter 4, owned by 137 parent companies, using information from D&B Hoover’s,<sup>154</sup> that could be affected by the final rule. Of the parent companies, 10 companies, or seven percent, are small entities. We also used information from D&B Hoover’s for the parent company revenues. We identified the NAICS code for all parent companies and applied the most current version of SBA’s table of size standards to determine which of the companies were small entities. Table 6-3 below includes the ranges NAICS codes and SBA entity size guidelines for small entity parent companies.

**Table 6-3. Non-EGU SBA Size Standards by NAICS Code**

NAICS Codes	NAICS U.S. Industry Title	Size Standards (million\$)	Size Standards (Number of employees)
212290	Other Metal Ore Mining		750
327211	Flat Glass Manufacturing		1,000
327212	Other Pressed and Blown Glass and Glassware Manufacturing		1,250
327213	Glass Container Manufacturing		1,250
327310	Cement Manufacturing		1,000
331110	Iron and Steel Mills and Ferroalloy Manufacturing		1,500
486210	Pipeline Transportation of Natural Gas	\$36.5	
322110	Pulp Mills		750
322120	Paper (except Newsprint) Mills		1,250
322130	Paperboard Mills		1,250
324110	Petroleum Refineries		1,500
324199	All Other Petroleum and Coal Products Manufacturing		500
325110	Petrochemical Manufacturing		1,000
325180	Other Basic Inorganic Chemical Manufacturing		1,000
325199	All Other Basic Organic Chemical Manufacturing		1,250

<sup>154</sup> D&B Hoovers is a subscription-based database that compiles publicly available information and can be found at <https://www.dnb.com/products/marketing-sales/dnb-hoovers.html>.

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NAICS Codes	NAICS U.S. Industry Title	Size Standards (million\$)	Size Standards (Number of employees)
562213	Solid Waste Combustors and Incinerators	\$41.5	

In addition, we identified several waste combustors owned by government entities at the county or city level. When evaluating the small entity impact to a government-owned facility the size of the population served by that government should be used as the basis for the small entity screening. In our analysis we identified 17 emissions units owned by five separate jurisdictions. None of the populations served by those governments are below the threshold for inclusion as a small entity.

We calculated the cost-to-sales ratios for all of the affected entities to determine (i) the magnitude of the costs of the rule, and (ii) whether there would be a significant impact on small entities compared to large entities. Non-EGUs do not operate in a price-regulated environment, like EGUs, where they are able to recover expenses through rate increases. As presented in Table 6-4 for *all* firms the average cost-to-sales ratio is approximately 0.2 percent; the median cost-to-sales ratio is less than 0.1 percent; and the maximum cost-to-sales ratio is approximately 2.4 percent. For *large* firms, the average cost-to-sales ratio is approximately 0.1 percent; the median cost-to-sales ratio is less than 0.1 percent; and the maximum cost-to-sales ratio is approximately 1.1 percent. For *small* firms, the average cost-to-sales ratio is approximately 0.8 percent, the median cost-to-sales ratio is 0.7 percent, and the maximum cost-to-sales ratio is 2.4 percent.

**Table 6-4. Summary of Sales Test Ratios for 2026 for Firms Affected by Proposed Rule**

Firm Size	No. of Known Affected Firms	% of Total Known Affected Firms	Mean Cost-to-Sales Ratio	Median Cost-to-Sales Ratio	Min. Cost-to-Sales Ratio	Max. Cost-to-Sales Ratio
Small	10	7.3%	0.8%	0.7%	<0.0%	2.4%
Large	127	92.7%	0.1%	<0.0%	<0.0%	1.1%
All	137	100.0%	0.2%	<0.0%	<0.0%	2.4%

As mentioned above, we compare annual compliance costs to annual revenues at the ultimate parent company level. Table 6-5 below includes the small parent companies and their projected cost-to-sales ratio, NAICS code, and small business size standards. The costs for the small parent companies ranged from \$12 thousand to \$2.3 million annually (2016\$).

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**Table 6-5. Summary of Small Parent Company Small Business Size Standards**

Small Parent Company	NAICS	Cost to Sales Ratio	SBA Business Small Size Standards		
			Small Parent Number of Employees	Annual Revenue (million\$)	Number of Employees
ND Fairmont LLC	322110	0.96%	250		750
Cobra Pipeline Company <sup>a</sup>	486210	2.40%	13	36.5	
Angus Chemical Company	325199	1.76%	500		1,250
Cstn Holdings	325199	0.86%	600		1,250
Empire Pipeline Corp <sup>a</sup>	486210	0.22%	8	36.5	
FutureFuel Chemical	325199	0.51%	460		1,250
Bear Island Paper Wb LLC	322120	0.73%	190		1,250
Deltech LLC	325110	0.61%	100		1,000
American Eagle Paper Mills	322120	0.42%	240		1,250
Savant Inc.	327212	0.03%	927		1,250

<sup>a</sup> These small entity parent companies were evaluated using the size standard for annual revenues.

### 6.1.3 Conclusion

Making a no SISNOSE (significant economic impacts on a substantial number of small entities) determination reflects an assessment of whether an estimated economic impact is significant and whether that impact affects a substantial number of small entities. We prepared an analysis of small entity impacts for EGUs and non-EGUs in 2026 separately and combined the 2026 results for a SISNOSE determination for the rule.

For EGUs in 2026, the analysis indicates that 19 small entities see a +/- 1 percent change in either summer NOx emissions, summer generation or summer fuel use, and none of these are projected to have a cost impact of greater than 1 percent of their revenues.

In 2026, the EPA identified 71 possibly affected EGU entities. Of these, the EPA identified 19 small entities affected by the rule, and of these no small entities may experience costs of greater than 1 percent of revenues. The EPA’s decision to exclude units smaller than 25 MW capacity from the FIP, and exclusion of uncontrolled units smaller than 100 MW from the backstop emission rate has already 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 10 small entities, and two small entities are estimated to have a cost-to-sales impact of more than one percent of their revenues.

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Based on this analysis, for this rule overall we conclude that the estimated costs for the final rule will not have a significant economic impact on a substantial number of small entities (SISNOSE).

## **6.2 Labor Impacts**

This section discusses potential employment impacts of this regulation. As economic activity shifts in response to a regulation, typically there will be a mix of declines and gains in employment in different parts of the economy over time and across regions. To present a complete picture, an employment impact analysis will describe the potential positive and negative changes in employment levels. There are significant challenges when trying to evaluate the employment effects due to an environmental regulation due to a wide variety of other economic changes that can affect employment, including the impact of the coronavirus pandemic on labor markets and the state of the macroeconomy generally. Considering these challenges, we look to the economics literature to provide a constructive framework and empirical evidence. To simplify, we focus on impacts on labor demand related to compliance behavior. Environmental regulation may also affect labor supply through changes in worker health and productivity (Graff, Zivin and Neidell, 2018).

Economic theory of labor demand indicates that employers affected by environmental regulation may increase their demand for some types of labor, decrease demand for other types, or for still other types, not change it at all (Morgenstern et al. 2002, Deschênes 2018, Berman and Bui 2001). To study labor demand impacts empirically, a growing literature has compared employment levels at facilities subject to an environmental regulation to employment levels at similar facilities not subject to that environmental regulation; some studies find no employment effects, and others find significant differences. For example, see Berman and Bui (2001), Greenstone (2002), Ferris, Shadbegian and Wolverton (2014), and Curtis (2018, 2020).

A variety of conditions can affect employment impacts of environmental regulation, including baseline labor market conditions and employer and worker characteristics such as occupation and industry. Changes in employment may also occur in different sectors related to the regulated industry, both upstream and downstream, or in sectors producing substitute or complimentary products. Employment impacts in related sectors are often difficult to measure.

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Consequently, we focus our labor impacts analysis primarily on the directly regulated facilities and other EGUs and related fuel markets and in the different non-EGU industry sectors.

#### *6.2.1 EGU Labor Impacts*

This section discusses and projects potential employment impacts for the utility power, coal and natural gas production sectors that may result from the rule. EPA has a long history of analyzing the potential impacts of air pollution regulations on changes in the amount of labor needed in the power generation sector and directly related sectors. The analysis conducted for this RIA builds upon the approaches used in the past and takes advantage of newly available data to improve the assumptions and methodology.<sup>155</sup>

The results presented in this section are based on a methodology that estimates the impact on employment based on the differences in projections between two modeling scenarios: the baseline scenario, and a scenario that represents the implementation of the rule. The estimated employment difference between these scenarios can be interpreted as the incremental effect of the rule on employment in this sector. As discussed in Chapter 4, there is uncertainty related to the future baseline projections, in part due to unknown impacts of the Inflation Reduction Act. Because the incremental employment estimates presented in this section are based on projections discussed in Chapter 4, it is important to highlight the relevance of the Chapter 4 uncertainty discussion to the analysis presented in this section.

Like previous analyses, this analysis represents an evaluation of “first-order employment impacts” using a partial equilibrium modeling approach. It includes some of the potential ripple effects of these impacts on the broader economy. These ripple effects include the secondary job impacts in both upstream and downstream sectors. The analysis includes impacts on upstream sectors including coal, natural gas, and uranium. However, the approach does not analyze impacts on other fuel sectors, nor does it analyze potential impacts related to transmission, distribution, or storage. This approach excludes the economy-wide employment effects of changes to energy markets (such as higher or lower forecasted electricity prices). This approach also excludes labor impacts that are sometimes reflected in a benefits analysis for an

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<sup>155</sup> For a detailed overview of this methodology, including all underlying assumptions, see the U.S. EPA Methodology for Power Sector-Specific Employment Analysis, available in the docket.

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environmental policy, such as increased productivity from a healthier workforce and reduced absenteeism due to fewer sick days of employees and dependent family members (e.g., children).

### *6.2.2 Overview of Methodology*

The methodology includes the following two general approaches, based on the available data. The first approach utilizes the rich employment data that is available for several types of generation technologies in the 2020 U.S. Energy and Employment Report.<sup>156</sup> For employment related to other electric power sector generating and pollution control technologies, the second approach utilizes information available in the U.S. Economic Census.

Detailed employment inventory data is available regarding recent employment related to coal, hydro, natural gas, geothermal, wind, and solar generation technologies. The data enables the creation of technology-specific factors that can be applied to model projections of capacity (reported in megawatts, or MW) and generation (reported in megawatt-hours, or MWh) in order to estimate impacts on employment. Since employment data is only available in aggregate by fuel type, it is necessary to disaggregate by labor type in order to differentiate between types of jobs or tasks for categories of workers. For example, some types of employment remain constant throughout the year and are largely a function of the size of a generator, e.g., fixed operation and maintenance activities, while others are variable and are related to the amount of electricity produced by the generator, e.g., variable operation and maintenance activities.

The approach can be summarized in three basic steps:

- Quantify the total number of employees by fuel type in a given year;
- Estimate total fixed operating & maintenance (FOM), variable operating & maintenance (VOM), and capital expenditures by fuel type in that year; and
- Disaggregate total employees into three expenditure-based groups and develop factors for each group (FTE/MWh, FTE/MW-year, FTE/MW new capacity).

Where detailed employment data is unavailable, it is possible to estimate labor impacts using labor intensity ratios. These factors provide a relationship between employment and

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<sup>156</sup> <https://www.usenergyjobs.org/>



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economic output and are used to estimate employment impacts related to construction and operation of pollution control retrofits, as well as some types of electric generation technologies.

For a detailed overview of this methodology, including all underlying assumptions and the types of employment represented by this analysis, see the U.S. EPA Methodology for Power Sector-Specific Employment Analysis, available in the docket.

### *6.2.3 Overview of Power Sector Employment*

In this section we focus on employment related to electric power generation, as well as coal and natural gas extraction because these are the segments of the power sector that are most relevant to the projected impacts of the rule. Other segments not discussed here include other fuels, energy efficiency, and transmission, distribution, and storage. The statistics presented here are based on the 2020 USEER, which reports data from 2019.<sup>157</sup>

In 2019, the electric power generation sector employed nearly 900,000 people. Relative to 2018, this sector grew by over 2 percent, despite job losses related to nuclear and coal generation. These losses were offset by increases in employment related to other generating technologies, including natural gas, solar, and wind. The largest component of total 2019 employment in this sector is construction (33%). Other components of the electric power generation workforce include utility workers (20%), professional and business service employees (20%), manufacturing (13%), wholesale trade (8%), and other (5%). In 2019, jobs related to solar and wind generation represent 31% and 14% of total jobs, respectively, and jobs related to coal generation represent 10% of total employment.

In addition to generation-related employment we also look at employment related to coal and natural gas use in the electric power sector. In 2019, the coal industry employed about 75,000 workers. Mining and extraction jobs represent the vast majority of total coal-related employment in 2019 (74%). The natural gas fuel sector employed about 276,000 employees in 2019. About 60% of those jobs were related to mining and extraction.

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<sup>157</sup> While 2020 data is available in the 2021 version of this report, this section of the RIA utilizes 2019 data because this year does not reflect any short-term trends related to the COVID-19 pandemic. The annual report is available at: <https://www.usenergyjobs.org/>.

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6.2.4 Projected Sectoral Employment Changes due to the Final Rule

Affected EGUs may respond to the rule through a number of means including optimizing existing controls, upgrading to state-of-the-art combustion controls, shifting generation from higher emitting to lower emitting sources, and installing new SCRs and SNCRs. Under the modeling of the final rule, 8 GW of SCR installations are projected by the 2030 run year, and an incremental 14 GW of coal retirements are projected by 2030. Additionally, EPA’s modeling of this rule projects an incremental 3 GW of non-hydro renewable additions, by 2025, and an additional 1 GW of non-hydro renewable and 9 GW of natural gas capacity by the 2030 run year.

Based on these power sector modeling projections, we estimate an increase in construction-related job-years related to the installation of new pollution controls under the rule, as well as the construction of new generating capacity (largely natural gas and solar PV). In 2025 and 2030, we estimate an increase of over 15,000 and 20,000 construction-related job-years, respectively, consistent with the projected increase in construction of new renewable and natural gas capacity in those years. Construction-related job-year changes are one-time impacts, occurring during each year of the multi-year periods during which construction of new capacity is completed. Construction-related figures in Table 6-6 represent a point estimate of incremental changes in construction jobs for each year (for a three-year construction projection, this table presents one-third of the total jobs for that project).

**Table 6-6. Changes in Labor Utilization: Construction-Related (Number of Job-Years of Employment in a Single Year)**

	2023	2025	2030
New Pollution Controls	<100	<100	2,800
New Capacity	<100	15,400	20,500

Note: “<100” denotes an increase or decrease of less than 100 job-years

We also estimate changes in the number of job-years related to recurring non-construction employment. Recurring employment changes are job-years associated with annual recurring jobs including operating and maintenance activities and fuel extraction jobs. Newly built generating capacity creates a recurring stream of positive job-years, while retiring generating capacity, as well as avoided capacity builds, create a stream of negative job-years. The rule is projected to result, generally, in a replacement of relatively labor-intensive coal capacity with less labor-intensive capacity, which results in an overall decrease of non-

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construction jobs. The rule is also projected to result in a small increase in recurring employment related to fuel extraction. The total net estimated decrease in recurring employment is less than 4,000 job-years in 2030, which is a small percentage of total 2019 power sector employment reported in the 2020 USEER (approximately 900,000 generation-related jobs, 75,000 coal-related jobs, and 276,000 natural gas-related jobs). Note that the projected decreases related to operation of existing pollution controls is consistent with the projected retirements of existing capacity. Table 6-7 provide detailed estimates of recurring non-construction employment changes.

**Table 6-7. Changes in Labor Utilization: Recurring Non-Construction (Number of Job-Years of Employment in a Single Year)**

	2023	2025	2030
Pollution Controls	<100	<100	<100
Existing Capacity	<100	-1,000	-6,700
New Capacity	<100	1,000	2,600
Fuels (Coal, Natural Gas, Uranium)	<100	<100	200
<i>Coal</i>	<100	<100	-200
<i>Natural Gas</i>	<100	<100	400
<i>Uranium</i>	<100	<100	<100

Note: “<100” denotes an increase or decrease of less than 100 job-years; Numbers may not sum due to rounding

#### 6.2.5 Non-EGU Labor Impacts

This section begins with a description of baseline conditions in non-EGU industries affected by the rule, focusing on the directly regulated industries and groups of affected workers. Table 6-8 shows the industry definitions and the NAICS codes used to categorizes the data for the relevant industries. The cement and concrete product manufacturing industry (NAICS 3273) by far is the largest regulated industry in terms of the number of people employed. BLS Current Employment Statistics show that the industry employs 186,000 people nationally. The iron and steel mills and ferroalloy manufacturing industry (NAICS 3311) and glass and glass product manufacturing industry (NAICS 3772) are similarly sized with 81,400 and 79,900 people employed, respectively. Each of the non-EGU industries has seen different trends in employment over the past decade. Both the pipeline transportation of natural gas (NAICS 4862) and cement and concrete product manufacturing industries saw sizable increases in employment over the past decade, but cement and concrete product manufacturing contracted in 2020 from the COVID-19

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pandemic. The iron and steel mills and ferroalloy manufacturing industry has seen steady decline in total employment, while the glass and glass product manufacturing industry has remained relatively constant over the last decade.<sup>158</sup>

**Table 6-8. Relevant Industry Employment (2020)**

	NAICS	Employment (Thousands)	Percent Change 2011 - 2020
Pipeline Transportation of Natural Gas	4862	49.1	19%
Cement and Concrete Product Manufacturing	3273	186.4	17%
Iron and Steel Mills and Ferroalloy Manufacturing	3311	81.4	-10%
Glass and Glass Product Manufacturing	3772	79.9	-1%
Basic Chemical Manufacturing	3251	150.1	5%
Petroleum and Coal Products Manufacturing	3241	106.5	-5%
Pulp, Paper, and Paperboard Mills	3221	92.6	-15%
Waste Treatment and Disposal	5622	101	4%
Metal Ore Mining	2122	41.7	11%

Source: BLS

These industries are capital intensive. We rely on two public sources to get a range of estimates of employment per output by sector: the Economic Census (EC), and the Annual Survey of Manufacturers (ASM), both provided by the U.S. Census Bureau. The EC is conducted every 5 years, most recently in 2017. The ASM is an annual subset of the EC and is based on a sample of establishments. The latest set of data from the ASM is from 2019. Both sets of U.S. Census Bureau data provide detailed industry data, providing estimates at the 4-digit NAICS level. They provide separate estimates of the number of employees and the value of shipments at the 4-digit NAICS, which we convert to a ratio in this employment analysis.

Table 6-9 provides estimates of employment per \$1 million of products sold by the industry for each data source in 2017\$. While the ratios are not the same, they are similar across time for both surveys. Glass and glass product manufacturing seems to be the most labor-intensive industry followed by waste treatment and disposal.

**Table 6-9. Employment per \$1 million Output**

Sector	Economic Census	ASM 2019
Pipeline Transportation of Natural Gas	1.21	N/A
Cement and Concrete Product Manufacturing	2.80	3.05
Iron and Steel Mills and Ferroalloy Manufacturing	0.97	0.91

<sup>158</sup> Bureau of Labor Statistics. BLS Employment, Hours, and Earnings from the Current Employment Statistics survey (National), All-employees, May 2021

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Glass and Glass Product Manufacturing	3.34	3.35
Basic Chemical Manufacturing	0.68	0.75
Petroleum and Coal Products Manufacturing	0.20	0.18
Pulp, Paper, and Paperboard Mills	1.24	1.30
Waste Treatment and Disposal	3.25	N/A
Metal Ore Mining	1.33	N/A

### 6.2.6 Conclusions

Generally, there are significant challenges when trying to evaluate the employment effects due to an environmental regulation from employment effects due to a wide variety of other economic changes, including the impact of the coronavirus pandemic on labor markets and the state of the macroeconomy generally. For EGUs, the Transport FIP for the 2015 ozone NAAQS may result in a sizable increase in construction-related jobs related to the installation of new pollution controls, as well as the construction of new generating capacity. The rule is also projected to result, generally, in a replacement of relatively labor-intensive coal capacity with less labor-intensive capacity, which results in an overall decrease of non-construction jobs. Speaking generally, a variety of federal programs are available to invest in communities potentially affected by coal mine and coal power plant closures. An initial report by The Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (April 2021) identifies funding available to invest in such “energy communities” through existing programs from agencies including Department of Energy, Department of Treasury, Department of Labor and others.<sup>159</sup> The Inflation Reduction Act also provides incentives to encourage investment in communities affected by coal mine and coal power plant closures.<sup>160</sup>

For the non-EGU industries, the employment trends over the last decade vary by industry. Without more detailed information on the labor required for installing pollution controls in these specific industries and other potential compliance approaches, we are not able to determine the potential effect of employment changes in the non-EGU industries.

<sup>159</sup> See “Initial Report to the President on Empowering Workers Through Revitalizing Energy Communities” April 2021 at [https://energycommunities.gov/wp-content/uploads/2021/11/Initial-Report-on-Energy-Communities\\_Apr2021.pdf](https://energycommunities.gov/wp-content/uploads/2021/11/Initial-Report-on-Energy-Communities_Apr2021.pdf)

<sup>160</sup> For more details see Congressional Research Service. “Inflation Reduction Act of 2022 (IRA): Provisions Related to Climate Change” October 3, 2022 at <https://crsreports.congress.gov/product/pdf/R/R47262>

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## CHAPTER 7: ENVIRONMENTAL JUSTICE IMPACTS

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### 7.1 Introduction

Executive Order 12898 directs the EPA to “achiev[e] environmental justice (EJ) by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects” (59 FR 7629, February 16, 1994), termed disproportionate impacts in this chapter. Additionally, Executive Order 13985 was signed to advance racial equity and support underserved communities through Federal government actions (86 FR 7009, January 20, 2021). The EPA defines EJ 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”.<sup>161</sup> Meaningful involvement means that: (1) potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health; (2) the public’s contribution can influence the regulatory Agency’s decision; (3) the concerns of all participants involved will be considered in the decision-making process; and (4) the rule-writers and decision-makers seek out and facilitate the involvement of those potentially affected.

The term “disproportionate impacts” refers to differences in impacts or risks that are extensive enough that they may merit Agency action.<sup>162</sup> In general, the determination of whether a disproportionate impact exists is ultimately a policy judgment which, while informed by analysis, is the responsibility of the decision-maker. The terms “difference” or “differential” indicate an analytically discernible distinction in impacts or risks across population groups. It is the role of the analyst to assess and present differences in anticipated impacts across population

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<sup>161</sup> See, e.g., “Environmental Justice.” *Epa.gov*, U.S. Environmental Protection Agency, 4 Mar. 2021, <https://www.epa.gov/environmentaljustice>.

<sup>162</sup> See <https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis>.

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groups of concern for both the baseline and proposed regulatory options, using the best available information (both quantitative and qualitative) to inform the decision-maker and the public.

A regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples through the action under development.

The Presidential Memorandum on Modernizing Regulatory Review (86 FR 7223; January 20, 2021) calls for procedures to “take into account the distributional consequences of regulations, including as part of a quantitative or qualitative analysis of the costs and benefits of regulations, to ensure that regulatory initiatives appropriately benefit, and do not inappropriately burden disadvantaged, vulnerable, or marginalized communities.” Under Executive Order 13563, federal agencies may consider equity, human dignity, fairness, and distributional considerations, where appropriate and permitted by law. For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 “Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,”<sup>163</sup> which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance.

A reasonable starting point for assessing the need for a more detailed EJ analysis is to review the available evidence from the published literature and from community input on what factors may make population groups of concern more vulnerable to adverse effects (e.g., underlying risk factors that may contribute to higher exposures and/or impacts). It is also important to evaluate the data and methods available for conducting an EJ analysis. EJ analyses can be grouped into two types, both of which are informative, but not always feasible for a given rulemaking:

1. **Baseline:** Describes the current (pre-control) distribution of exposures and risk, identifying potential disparities.

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<sup>163</sup> See <https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis>.



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2. **Policy:** Describes the distribution of exposures and risk after the regulatory option(s) have been applied (post-control), identifying how potential disparities change in response to the rulemaking.

The EPA’s 2016 Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting EJ analyses, though a key consideration is consistency with the assumptions underlying other parts of the regulatory analysis when evaluating the baseline and regulatory options.

## **7.2 Analyzing EJ Impacts in This Final Rule**

In addition to the benefits assessment (Chapter 5), the EPA considers potential EJ concerns associated with this final rulemaking. A potential EJ concern is defined as “the actual or potential lack of fair treatment or meaningful involvement of minority populations, low-income populations, tribes, and indigenous peoples in the development, implementation and enforcement of environmental laws, regulations and policies” (U.S. EPA, 2015). For analytical purposes, this concept refers more specifically to “disproportionate impacts on minority populations, low-income populations, and/or indigenous peoples that may exist prior to or that may be created by the proposed regulatory action” (U.S. EPA, 2015). Although EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, the EPA’s EJ Technical Guidance (U.S. EPA, 2015) states that “[t]he 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 [, exacerbated,] or mitigated compared to the baseline?”

To address these questions, EPA developed an analytical approach that considers the purpose and specifics of the rulemaking, as well as the nature of known and potential exposures across various demographic groups. For example, while we recognize that the final rule is

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focused on reducing NO<sub>x</sub> emissions to implement obligations for 23 states under the “Good Neighbor” provision of the Clean Air Act to eliminate significant contribution to nonattainment and interference with maintenance of the 2015 ozone National Ambient Air Quality Standards (NAAQS) in other states, this rulemaking may also reduce other pollutant emissions, such as nitrogen dioxide (NO<sub>2</sub>).

Like other oxides of nitrogen, NO<sub>2</sub> can contribute to the formation of ozone and PM<sub>2.5</sub> downwind of sources; however, direct emissions of NO<sub>2</sub> can also lead to localized exposures that may be associated with respiratory effects in nearby populations at sufficiently high concentrations. In addition, people with asthma, children (especially ages 0–14 years), and older adults (especially ages 65 years and older) are identified as being at increased risk of NO<sub>2</sub>-related health effects (U.S. EPA 2016). While NO<sub>2</sub> exposures and concentrations were not evaluated as part of this rule, proximity analyses of affected EGU and non-EGU facilities were performed as local exposures may be relevant to the baseline and/or change due to this action (Section 7.3).<sup>164</sup> In contrast, proximity analyses should not be used to interpret ozone and PM<sub>2.5</sub> exposure impacts due to this rulemaking, as ozone is secondarily formed and both pollutants can undergo long-range transport.

To directly assess EJ ozone and PM<sub>2.5</sub> exposure impacts, [the](#) EPA conducts an analysis of reductions in modeled ozone and PM<sub>2.5</sub> concentrations nationwide resulting from the NO<sub>x</sub> emissions reductions projected to occur under the rule, characterizing aggregated and distributional exposures both prior to and following implementation of the three regulatory alternatives in 2023 and 2026 (Section 7.4).

Unique limitations and uncertainties are specific to each type of analysis, which are described prior to presentation of analytic results in the subsections below.

### **7.3 Demographic Proximity Analyses**

Demographic proximity analyses allow one to assess the potentially vulnerable populations residing nearby affected facilities as a proxy for exposure and the potential for adverse health impacts that may occur at a local scale due to economic activity at a given

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<sup>164</sup> EPA is considering if and how to incorporate NO<sub>2</sub> health benefits into rulemakings. The ISA states that a key uncertainty in understanding the relationship between non-respiratory health effects and short- or long-term exposure to NO<sub>2</sub> is co-pollutant confounding, particularly by other traffic pollutants.

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location including noise, odors, traffic, and emissions such as NO<sub>2</sub>, covered under this EPA action and not modeled elsewhere in this RIA.

Although baseline proximity analyses are presented here, several important caveats should be noted. In most areas, emissions are not expected to increase from the rulemaking, so most communities nearby affected facilities should experience decreases in exposure from directly emitted pollutants. However, facilities may vary widely in terms of the impacts on populations they already pose to nearby populations. In addition, proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur and should not be interpreted as a direct measure of exposure or impact. These points limit the usefulness of proximity analyses when attempting to answer question from EPA’s EJ Technical Guidance.

Demographic proximity analyses were performed for two subsets of affected facilities:

- *Electricity Generating Unit (EGU)*: Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living nearby covered EGU sources to average national levels.
- *Non-EGU (non-electric generating units, or other stationary emissions sources)*: Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living nearby covered non-EGU sources to average national levels.

### 7.3.1 EGU Proximity Assessments

The current analysis identified all census blocks with centroids within a 5 km, 10 km and 50 km radius of the latitude/longitude location of each facility, and then linked each block with census-based demographic data.<sup>165</sup> The total population within a specific radius around each facility is the sum of the population for every census block within that specified radius, based on

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<sup>165</sup> Five km and 50 km radii are the default distances currently used for proximity analyses. The 5 km distance is the shortest distance that should be chosen to avoid excessive demographic uncertainty and provides information on near-field populations. The 50 km distance offers a sub-regional perspective. The 10 km distance was added to this analysis as few to no people were within 5 km of some affected facilities.

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each block's population provided by the decennial Census.<sup>166</sup> Statistics on race, ethnicity, age, education level, poverty status and linguistic isolation were obtained from the Census' American Community Survey (ACS) 5-year averages for 2015-2019. These data are provided at the block group level. For the purposes of this analysis, the demographic characteristics of a given block group – that is, the percentage of people in different races/ethnicities, the percentage in different age groups (<18, 18-64, and >64), the percentage without a high school diploma, the percentage that are below the poverty level, and the percentage that are linguistically isolated – are presumed to also describe each census block located within that block group.

In addition to facility-specific demographics, the demographic composition of the total population within the specified radius (e.g., 50 km) for all facilities as a whole was also computed (e.g., all EGUs or all non-EQU facilities). In calculating the total populations, to avoid double-counting, each census block population was only counted once. That is, if a census block was located within the selected radius (i.e., 50 km) for multiple facilities, the population of that census block was only counted once in the total population. Finally, this analysis compares the demographics at each specified radius (i.e., 5 km, 10 km, and 50 km) to the demographic composition of the nationwide population.

For this action, a demographic analysis was conducted for 711 EGU facilities at the 5 km, 10 km, and 50 km radius distances (Table 7-1). Approximately 158 million people live within 50 km of the EGU facilities, representing roughly 48% of the 328 million total population of the U.S. The percent demographic make-up of the population within 50 km of the EGU facilities is very similar to the national average for each demographic investigated. Approximately 18.1 million and 48.1 million people live within 5 km and 10 km of the EGU facilities, respectively. The demographic make-up of the population within 5 km and 10 km of EGU facilities are very similar. Within 5 km and 10 km of EGU facilities, there is a higher Hispanic/Latino population (about 3 to 5% above national average) and a higher African American population (about 5 to 6% above national average). The age distribution for the population within 5 km and 10 km of EGU facilities is similar to the national average. The percent of people living below the poverty level is about 3% higher within 5 km and 10 km of the EGU facilities than the national average.

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<sup>166</sup> The location of the Census block centroid is used to determine if the entire population of the Census block is assumed to be within the specified radius. It is unknown how sensitive these results may be to different methods of population estimation, such as aerial apportionment.

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About 7% to 8% of the population within 5 km and 10 km of the EGU facilities is living in linguistic isolation, this is higher than the national average of 5%.

**Table 7-1. Population Demographics for EGU Facilities**

Demographic Group	Percent of Population Within Each Distance Compared to the National Average <sup>1</sup>				
	5km	10km	50km	National Average	
Race/ Ethnicity	White	49.6%	50.7%	62.7%	60.1%
	African American	17.0%	18.3%	14.6%	12.2%
	Native American	0.4%	0.4%	0.4%	0.7%
	Other and Multiracial	9.3%	8.6%	7.1%	8.2%
	Hispanic or Latino <sup>2</sup>	23.7%	21.9%	15.2%	18.8%
Age	0-17 Years Old	21.9%	22.5%	22.5%	22.6%
	18-64 Years Old	63.9%	62.9%	61.9%	61.7%
	>=65 Years Old	14.2%	14.6%	15.6%	15.7%
Income	People Living Below the Poverty Level	16.8%	15.9%	13.2%	13.4%
Education	>= 25 Years Old Without a High School Diploma	15.2%	14.3%	11.7%	12.1%
Language	People Living in Linguistic Isolation	8.1%	7.3%	4.5%	5.4%
<b>Total Population</b>		<b>18,094,722</b>	<b>48,062,338</b>	<b>157,740,319</b>	<b>328,016,242</b>

<sup>1</sup> Demographic percentage is based on the Census' 2015-2019 American Community Survey 5-year averages, at the block group level, and include the 50 states, District of Columbia, and Puerto Rico. Total population is based on block level data from the 2010 Decennial Census.

<sup>2</sup> To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census.

### 7.3.2 Non-EGU Proximity Analysis

For this action, a demographic analysis was also conducted for 482 non-EGU facilities at the 5 km, 10 km, and 50 km radius distances (Table 7-2). Approximately 130 million people live within 50 km of the non-EGU facilities, representing roughly 40% of the 328 million total population of the U.S. The percent demographic make-up of the population within 50 km of the non-EGU facilities is very similar to the national average for each demographic investigated. Approximately 5.7 million and 19.3 million people live within 5 km and 10 km of the non-EGU facilities, respectively. The demographic make-up of the population within 5 km and 10 km of non-EGU facilities are similar. Within 5 km and 10 km of non-EGU facilities, the African American population is 6% higher than the national average. The age distribution for the population within 5 km and 10 km of non-EGU facilities is similar to the national average. The

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percent of people living below the poverty level within 5 km and 10 km of the non-EGU facilities is about 2 to 4% higher than the national average. The percent of the population within 5 km and 10 km of the non-EGU facilities living in linguistic isolation is about the same as the national average (about 5%).

**Table 7-2. Population Demographics for Non-EGU Facilities**

Demographic Group		Percent of Population Within Each Distance Compared to the National Average <sup>1</sup>			
		5km	10km	50km	National Average
Race/ Ethnicity	White	55.6%	56.8%	59.0%	60.1%
	African American	18.2%	18.2%	14.1%	12.2%
	Native American	0.5%	0.4%	0.4%	0.7%
	Other and Multiracial	6.1%	7.1%	8.9%	8.2%
	Hispanic or Latino <sup>2</sup>	19.7%	17.4%	17.6%	18.8%
Age	0-17 Years Old	22.9%	22.2%	22.1%	22.6%
	18-64 Years Old	62.5%	62.4%	62.2%	61.7%
	>=65 Years Old	14.6%	15.3%	15.7%	15.7%
Income	People Living Below the Poverty Level	17.7%	15.3%	13.5%	13.4%
Education	>= 25 Years Old Without a High School Diploma	15.7%	13.5%	12.8%	12.1%
Language	People Living in Linguistic Isolation	5.4%	4.8%	5.4%	5.4%
<b>Total Population</b>		<b>5,743,473</b>	<b>19,284,115</b>	<b>130,446,759</b>	<b>328,016,242</b>

<sup>1</sup> Demographic percentage is based on the Census' 2015-2019 American Community Survey 5-year averages, at the block group level, and include the 50 states, District of Columbia, and Puerto Rico. Total population is based on block level data from the 2010 Decennial Census.

<sup>2</sup> To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census.

For additional information on the EGU or non-EGU proximity analyses, see the memorandum *Analysis of Demographic Factors For Populations Living Near EGU and Non-EGU Facilities*, in the rulemaking docket.

#### 7.4 EJ Ozone and PM<sub>2.5</sub> Exposure Impacts

This EJ air pollutant exposure<sup>167</sup> analysis aims to evaluate the potential for EJ concerns related to PM<sub>2.5</sub> and ozone exposures<sup>168</sup> among potentially vulnerable populations. To assess EJ ozone and PM<sub>2.5</sub> exposure impacts, we focus on the first and third of the three EJ questions from the EPA’s 2016 EJ Technical Guidance,<sup>169</sup> which ask if there are potential EJ concerns associated with stressors affected by the regulatory action for population groups of concern in the baseline and if those potential EJ concerns in the baseline are exacerbated, mitigated, or unchanged under the regulatory options being considered.<sup>170</sup>

To address these questions with respect to the air pollutants ozone and PM<sub>2.5</sub>, the EPA developed an analytical approach that considers the purpose and specifics of this final rulemaking, as well as the nature of known and potential exposures and impacts. Specifically, as 1) this final rule affects EGUs across the U.S., which typically have tall stacks that result in emissions from these sources being dispersed over large distances, and 2) both as ozone and PM<sub>2.5</sub> can undergo long-range transport, it is appropriate to conduct an EJ assessment of the contiguous U.S. Given the availability of modeled baseline and policy PM<sub>2.5</sub> and ozone air quality surfaces, we conduct an analysis of changes in PM<sub>2.5</sub> and ozone concentrations resulting from the emission changes projected by the Integrated Planning Model (IPM) to occur under the final rule as compared to the baseline scenario, characterizing average and distributional exposures following implementation of the regulatory alternatives in 2023 and 2026. However, several important caveats of this analysis are as follows:

<sup>167</sup> The term exposure is used here to describe estimated ozone and PM<sub>2.5</sub> concentrations and not individual dosage.

<sup>168</sup> Air quality surfaces used to estimate exposures are based on 12 km x 12 km grids. Additional information on air quality modeling can be found in the air quality modeling information section.

<sup>169</sup> U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions. <https://www.epa.gov/sites/default/files/2015-06/documents/considering-ej-in-rulemaking-guide-final.pdf>

<sup>170</sup> EJ question 2, which asks if there are potential EJ concerns (i.e., disproportionate burdens across population groups) associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory options under consideration, was not focused on for several reasons. Importantly, the total magnitude of differential exposure burdens with respect to ozone and PM<sub>2.5</sub> among population groups at the national scale has been fairly consistent pre- and post-policy implementation across recent rulemakings. As such, differences in nationally aggregated exposure burden averages between population groups before and after the rulemaking tend to be very similar. Therefore, as disparities in pre- and post-policy burden results appear virtually indistinguishable, the difference attributable to the rulemaking can be more easily observed when viewing the change in exposure impacts, and as we had limited available time and resources, we chose to provide quantitative results on the pre-policy baseline and policy-specific impacts only, which related to EJ questions 1 and 3. We do however use the results from questions 1 and 3 to gain insight into the answer to EJ question 2 in the summary (Section 7.6).

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- Modeling of post-policy air quality concentration changes are based on state-level emission data paired with facility-level baseline emissions. The air quality surfaces will capture expected air quality changes that result from state-to-state emissions change but will not capture heterogeneous changes in emissions from multiple facilities within a single state.
- Air quality simulation input information are at a 12km x 12km grid resolution and population information is either at the Census tract- or county-level, potentially masking impacts at geographic scales more highly resolved than the input information.
- The two specific air pollutant metrics evaluated in this assessment, warm season maximum daily 8-hour ozone average concentrations and average annual PM<sub>2.5</sub> concentrations, are focused on longer-term exposures that have been linked to adverse health effects. This assessment does not evaluate disparities in other potentially health-relevant metrics, such as shorter-term exposures to ozone and PM<sub>2.5</sub>.
- In the source apportionment modeling we aggregate emissions from point sources on all Tribal lands into a single nationwide source tag. Using a single nationwide Tribal tag will affect the spatial distribution pollutant impacts. In this respect, the NO<sub>x</sub> reductions at the Bonanza power plant in the 2026 final rule policy and more stringent alternatives impact pollutant concentrations in and around all Tribal lands. This is most evident in and around the Four Corners Generating Station in northwestern New Mexico where there are predicted pollutant reductions even though there are no controls applied to units at this facility.
- PM<sub>2.5</sub> EJ impacts were limited to exposures, and do not extend to health effects, given additional uncertainties associated with estimating health effects stratified by demographic population and the ability to predict differential PM<sub>2.5</sub>-attributable EJ health impacts.
- Relative to the proposed rule, the final rule defers the backstop daily NO<sub>x</sub> emission rate from 2027 to no later than 2030 for those EGUs that do not have an SCR. In this analysis, we capture ozone and PM<sub>2.5</sub> exposure impacts in 2026 across the final, less stringent, and more stringent alternative for EGUs, but do not account for impacts of projected exposure changes in 2030 due to the backstop. However, given the IPM modeling in Chapter 4, we expect exposure reductions to be greater in 2030 for the final rule relative to the more stringent alternative.

Population variables considered in this EJ exposure assessment include race, ethnicity, educational attainment, employment status, health insurance status, linguistic isolation, poverty status, age, and sex (Table 7-3).<sup>171</sup>

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<sup>171</sup> Population projections stratified by race/ethnicity, age, and sex are based on economic forecasting models developed by Woods and Poole (Woods and Poole, 2015). The Woods and Poole database contains county-level projections of population by age, sex, and race out to 2050, relative to a baseline using the 2010 Census data.



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**Table 7-3. Demographic Populations Included in the Ozone and PM<sub>2.5</sub> EJ Exposure Analyses**

Demographic	Groups	Ages	Spatial Scale of Population Data
Race	Asian; American Indian; Black; White	0-99	Census tract
Ethnicity	Hispanic; Non-Hispanic	0-99	Census tract
Educational Attainment	High school degree or more; No high school degree	25-99	Census tract
Employment Status	Employed; Unemployed; Not in the labor force	0-99	County
Health Insurance	Insured; Uninsured	0-64	County
Linguistic Isolation	Speaks English “very well” or better; Speaks English less than “very well” OR Speaks English “well” or better; Speaks English less than “well”	0-99	Census tract
Poverty Status	Above the poverty line; Below the poverty line OR Above 2x the poverty line; Below 2x the poverty line	0-99	Census tract
Age	Children	0-17	Census tract
	Adults	18-64	
	Older Adults	65-99	
Sex	Female; Male	0-99	Census tract

#### 7.4.1 Ozone Exposure Analysis

To evaluate the potential for EJ concerns among potentially vulnerable populations resulting from exposure to ozone under the baseline and regulatory control alternatives in this rule, we assess the impact of NOx emissions reductions on downwind ozone concentrations. EPA presents an analysis of ozone concentrations associated with upwind NOx emissions, characterizing the distribution of exposures both prior to and following implementation of the final rule, as well as of the more and less stringent regulatory alternatives, in 2023 and 2026. Under the final rule and more stringent regulatory alternative, the year of full compliance is 2026 for both EGUs and non-EGUs, except for the EGU backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls, which occurs in ~~2030~~[2030 in](#) the final rule (emissions budgets in 2026 are commensurate with a backstop rate in place). Under

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Population projections for each county are determined simultaneously with every other county in the U.S to consider patterns of economic growth and migration. County-level estimates of population percentages within the poverty status and educational attainment groups were derived from 2015-2019 5-year average ACS estimates. Additional information can be found in Appendix J of the BenMAP-CE User’s Manual (<https://www.epa.gov/benmap/benmap-ce-manual-and-appendices>).

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the less stringent scenario the year of full compliance is 2030 for EGUs and 2026 for non-EGUs.<sup>172</sup>

As this analysis is based on the same ozone spatial fields as the benefits assessment (see Chapter 3 for a discussion of the spatial fields), it is subject to similar types of uncertainty (see Chapter 5, Section 5.1.3 for a discussion of the uncertainty). A particularly germane limitation is that ozone, being a secondary pollutant, is the byproduct of complex atmospheric chemistry such that direct linkages cannot be made between specific affected facilities and downwind ozone concentration changes based on available air quality modeling (see Chapter 3, Section 3.4).

Ozone concentration and exposure metrics can take many forms, although only a small number are commonly used. The analysis presented here is based on the average April-September warm season maximum daily 8-hour average ozone concentrations (AS-MO3), consistent with the health impact functions used in the benefits assessment (Chapter 5). As developing spatial fields is time and resource intensive, the same spatial fields used for the benefits analysis were also used for the ozone exposure analysis performed here to assess EJ impacts.

The construct of the AS-MO3 ozone metric used for this analysis should be kept in mind when attempting to relate the results presented here to the ozone NAAQS and when interpreting the confidence in the association between exposures and health effects. Specifically, the seasonal average ozone metric used in this analysis is not constructed in a way that directly relates to NAAQS design values, which are based on daily maximum 8-hour concentrations.<sup>173</sup> Thus, AS-MO3 values reflecting seasonal *average* concentrations well below the level of the NAAQS at a particular location do not necessarily indicate that the location does not experience any *daily* (8-hour) exceedances of the ozone NAAQS. Relatedly, [the EPA](#) is confident that reducing the highest ambient ozone concentrations will result in substantial improvements in public health, including reducing the risk of ozone-associated mortality. However, the Agency is less certain about the public health implications of changes in relatively low ambient ozone concentrations.

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<sup>172</sup> We did not evaluate or bring in stratified baseline incidence rates or concentration-response functions relating to potentially evaluating at-risk populations. As results of a risk analysis lacking stratified concentration-response and/or baseline incidence rates would not provide additional information regarding population group impacts beyond exposure differences and age-related difference in baseline incidence, this EJ analysis was limited to exposure only.

<sup>173</sup> Level of 70 ppb with an annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years.

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Most health studies rely on a metric such as the warm-season average ozone concentration; as a result, the EPA typically utilizes air quality inputs such as the AS-MO3 spatial fields in the benefits assessment, and we judge them also to be the best available air quality inputs for this EJ ozone exposure assessment. To further support the use of the AS-MO3 spatial fields in this ozone analysis, we compared baseline AS-MO3 spatial fields with average baseline maximum daily 1-hour average (MDA1) ozone concentrations spatial fields in the proposal for this rulemaking, also over the April-September warm season, and found that average population ozone concentration trends within populations were similar when considering either the AS-MO3 or the MDA1 spatial fields. Therefore, in this final rulemaking, we performed ozone analyses using only the AS-MO3 metric over the April-September warm season.

The metric and averaging season are also relevant inputs to consider when interpreting the results as they can affect the sharpness of pollutant gradients, an important factor when associating exposure for different demographic populations. Figure 3-2 and Figure in Chapter 3 of this RIA show maps of the baseline 12 km gridded AS-MO3 concentrations in 2023 and 2026, respectively. As the AS-MO3 seasonal metric is based on the average of concentrations over more than 180 days in the spring and summer, the resulting spatial fields are relatively smooth and do not display sharp gradients, compared to what might be expected when looking at the spatial patterns of the average maximum daily 8-hour average ozone concentrations on individual high ozone episode days.

The ozone exposure analyses begin with heat maps of national- and state-level aggregated results (Section 7.4.1.1) and then examines spatially resolved distributional results via figures (Section 7.4.1.3).

#### *7.4.1.1 Aggregated Results*

Results aggregated to the national and state levels provide an overview of the average impacts within each population group. We provide baseline results in absolute terms (i.e., total AS-MO3 concentrations) and regulatory alternative results in relative terms (i.e., the change in AS-MO3 concentrations).

As inclusion of additional “on the books” regulations could impact the pre-policy scenario, it is important to begin by evaluating the baseline, or pre-regulatory, conditions.

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Average baseline AS-MO3 concentrations in parts per billion (ppb) in the two modeled future years, 2023 and 2026, are shown in the colored columns of the below heat maps (Figure 7-1 and Figure 7-2). Concentrations in the “baseline” column represent the total estimated ozone exposure burden averaged over the 6-month warm season each year and are colored to more easily visualize differences in average concentrations, with lighter green coloring representing lower average concentrations and darker green coloring representing higher average concentrations.

Average ozone concentrations are estimated to increase slightly across the overall reference population (top row) between 2023 and 2026 by approximately 0.5 ppb. While many of the average ozone concentrations within the individual population groups are estimated to be similar to or below average concentrations of the overall reference group (i.e., the total population of contiguous U.S.), certain populations are estimated to experience higher average ozone concentrations in the baseline in both future years. Populations with national average ozone concentrations higher than the reference population in both 2023 and 2026 ordered from most to least difference were: American Indians, Hispanics, linguistically isolated, Asians, the less educated, and children. These populations live in areas with seasonal average baseline ozone concentrations of up to 2.1 ppb higher than the national average concentrations.<sup>174</sup> In contrast, national average baseline ozone concentrations in the Black population are estimated to be about 1.2 ppb less than the reference group in both 2023 and 2026. However, it is important to note that these are aggregate results across broad areas and large numbers of people, which may underestimate the impact in individual locations where there is both an ozone nonattainment issue and a disproportionately large racial/ethnic population. Additionally, while average AS-MO3 exposures across all groups are relatively low (~40-43 ppb), these seasonal estimates do not necessarily indicate that individual locations do not experience exceedances of the NAAQS. Thus, it is difficult to draw conclusions from this analysis about whether some population subgroups experience hyperlocal higher daily maximum exposures than others in the baseline.

Overall, the national-level baseline assessment of ozone concentrations suggests that there may be potential EJ exposure concerns for certain population groups of concern in the

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<sup>174</sup> Differences in both 2023 and 2026 were calculated and averaged to generate these estimates, as differences between the air quality in the two future years were similar.

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baseline. Specifically, the data indicate that some population subgroups evaluated may experience slightly elevated seasonal average ozone concentrations in the baseline as compared to the reference group nationally.

The right sides of Figure 7-1 and Figure 7-2 provide information regarding how the final rulemaking will impact ozone concentrations across various populations.<sup>175</sup> Figure 7-3 shows how ozone concentrations may change in 2023 (from EGU controls only) and in 2026 (from EGUs controls, non-EGU controls, and EGU and non-EGU controls combined) under the rule, the less stringent alternative, and the more stringent alternative. Under the final rule, the population-weighted seasonal average ozone reduction in the overall reference group is approximately 0.03 ppb in 2023 and 0.3 ppb in 2026. The relative population-weighted AS-MO3 ozone concentration reduction contributions from EGUs and non-EGUs can be directly compared in 2026. 0.1 ppb of ozone concentration reductions are attributable to affected EGUs and 0.2 ppb are attributable to non-EGU affected facilities. Hispanics, Asians, American Indians, and linguistically isolated populations are estimated to experience reductions in AS-MO3 that are slightly less than the reference group in both 2023 and 2026. Pairing these results with the national baseline ozone concentrations suggests that although this rule lessens overall ozone concentrations within each population as compared with the baseline levels, reductions are smallest in populations with higher baseline ozone concentrations. However, the relative differences in the policy impacts are small (e.g., on the order of ~0.1 ppb less reduction in ozone among these subpopulations as compared to the reference group) and substantially smaller than the baseline differences across these subpopulations (~2 ppb). Conversely, Black and non-Hispanic individuals, who on average experience lower ozone concentrations than the reference group under the baseline, are estimated to experience average ozone concentration reductions

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<sup>175</sup> The final rule and less stringent scenario defer the backstop emission rate for certain EGUs until the 2030 run year, while the more stringent alternative imposes the backstop emission rate in the 2025 run year. Retirements that may be undertaken by EGU source owners/operators as a least-cost compliance strategy are therefore delayed in the final rule and less stringent alternative relative to the more stringent alternative. Since the power sector model is forward looking, it has an incentive to run units harder before they retire. This incentive is lower in the final rule and less stringent alternative relative to the more stringent alternative due to delayed retirements. As such, emissions are slightly lower in 2023 in some states in the less stringent alternative and final rule relative to the more stringent alternative, leading to slightly greater emissions reductions.

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slightly greater than the reference group in 2023 and 2026. Again, these differences are small relative to the overall reduction in ozone concentrations across all populations.<sup>176</sup>

Under the less stringent regulatory alternative in 2023 there are similar magnitudes of ozone concentration reductions in the reference group as in the rule, and a greater reduction in average ozone concentration in the more stringent regulatory alternative, within all population groups. In 2026 the less stringent and more stringent alternatives are estimated to result in smaller and larger reductions in ozone concentrations, respectively, as compared to the final rule. Notably, the less stringent alternative has smaller ozone concentration reductions from EGUs than from non-EGUs, whereas the more stringent alternative has slightly larger ozone concentration reductions from both EGUs and non-EGUs.

The national-level assessment of ozone before and after implementation of this final rulemaking suggests that while EJ exposure disparities are present in the pre-policy scenario, meaningful EJ exposure concerns are not likely created or exacerbated by the rule for the population groups evaluated. In other words, the data indicate that all population subgroups evaluated may experience similar seasonal average ozone concentration changes after implementation of this rule as compared to the reference group nationally.

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<sup>176</sup> We report average exposure results to the decimal place where difference between demographic populations become visible, as we cannot provide a quantitative estimate of the air quality modeling precision uncertainty. Using this approach allows for a qualitative consideration of uncertainties and the significance of the relatively small differences.

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Population	Group	Population Count	2023			
			Baseline	Final	Less	More
Reference	Reference (0-99)	343M	41.30	0.03	0.03	0.03
Race	White (0-99)	270M	41.39	0.03	0.03	0.03
	American Indian (0-99)	4M	43.41	0.04	0.04	0.04
	Asian (0-99)	22M	42.44	0.02	0.02	0.02
	Black (0-99)	47M	40.13	0.03	0.03	0.04
Ethnicity	Non-Hispanic (0-99)	275M	40.83	0.03	0.03	0.04
	Hispanic (0-99)	68M	43.22	0.02	0.02	0.02
Linguistic	English "well or better" (0-99)	327M	41.24	0.03	0.03	0.03
Isolation	English < "well" (0-99)	16M	42.55	0.02	0.02	0.02
Poverty	<Poverty line (0-99)	54M	41.31	0.03	0.03	0.03
Status	>Poverty line (0-99)	288M	41.30	0.03	0.03	0.03
Educational Attainment	More educated (>24: HS or more)	201M	41.13	0.03	0.03	0.03
	Less educated (>24; no HS)	33M	41.70	0.03	0.03	0.03
Employment Status	Employed (0-99)	9M	41.71	0.03	0.03	0.03
	Unemployed (0-99)	343M	41.30	0.03	0.03	0.03
	Not in the labor force (0-99)	174M	41.27	0.03	0.03	0.03
Insurance Status	Insured (0-64)	251M	41.44	0.03	0.03	0.03
	Uninsured (0-64)	30M	41.00	0.03	0.03	0.03
Age	Children (0-17)	78M	41.54	0.03	0.03	0.03
	Adults (18-64)	204M	41.34	0.03	0.03	0.03
	Older Adults (65-99)	61M	40.89	0.03	0.03	0.03
Sex	Females (0-99)	174M	41.29	0.03	0.03	0.03
	Males (0-99)	169M	41.31	0.03	0.03	0.03

Figure 7-1. Heat Map of the National Average AS-MO3 Ozone Concentrations in the Baseline and Reductions in Concentrations Due to this Rulemaking Across Demographic Groups in 2023 (ppb)

Population	Group	Population Count	Baseline	2026								
				EGU	NonEGU	EGU+NonEGU	EGU	NonEGU	EGU+NonEGU	EGU	NonEGU	EGU+NonEGU
Reference	Reference (0-99)	352M	41.8	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
Race	White (0-99)	276M	41.9	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.3	0.6
	American Indian (0-99)	4M	43.9	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.3	0.5
	Asian (0-99)	24M	42.8	0.1	0.2	0.3	0.0	0.1	0.1	0.1	0.3	0.5
	Black (0-99)	49M	40.6	0.1	0.3	0.4	0.0	0.1	0.1	0.2	0.4	0.6
Ethnicity	Non-Hispanic (0-99)	279M	41.3	0.1	0.2	0.4	0.0	0.1	0.1	0.2	0.4	0.6
	Hispanic (0-99)	73M	43.6	0.1	0.2	0.2	0.0	0.1	0.1	0.2	0.3	0.5
Linguistic	English "well or better" (0-99)	336M	41.7	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
Isolation	English < "well" (0-99)	16M	42.9	0.1	0.2	0.2	0.0	0.1	0.1	0.1	0.3	0.5
Poverty	<Poverty line (0-99)	55M	41.8	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
Status	>Poverty line (0-99)	296M	41.8	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
Educational Attainment	More educated (>24: HS or more)	207M	41.6	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.3	0.6
	Less educated (>24; no HS)	34M	42.2	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
Employment Status	Employed (0-99)	9M	42.2	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
	Unemployed (0-99)	352M	41.8	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
	Not in the labor force (0-99)	179M	41.8	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
Insurance Status	Insured (0-64)	255M	41.9	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
	Uninsured (0-64)	31M	41.5	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
Age	Children (0-17)	80M	42.0	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
	Adults (18-64)	206M	41.8	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
	Older Adults (65-99)	67M	41.4	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.3	0.5
Sex	Females (0-99)	178M	41.8	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6
	Males (0-99)	174M	41.8	0.1	0.2	0.3	0.0	0.1	0.1	0.2	0.4	0.6

Figure 7-2. Heat Map of the National Average AS-MO3 Ozone Concentrations in the Baseline and Reductions in Concentrations Due to this Rulemaking Across Demographic Groups in 2026 (ppb)

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#### *7.4.1.2 State Aggregated Results*

The goal of this action is to require NOx emissions reductions that will eliminate significant contribution to nonattainment or interference with maintenance of the 2015 ozone NAAQS in downwind areas.<sup>177</sup> As upwind emissions reductions necessary to achieve this goal will not affect ozone concentrations uniformly within each state, we provide AS-MO3 ozone concentration changes by state and demographic population for the two future years (Figure 7-3 and Figure 7-4). Figure 7-3 shows the EGU impacts in 2023 and Figure 7-4 shows the combined EGU and non-EGU impacts in 2026 for the 48 states in the contiguous U.S, for the policy scenario only. In these heat maps darker green indicates larger AS-MO3 reductions and red colors show AS-MO3 increases, although the demographic groups are now shown as columns and each state as a row. On average, the state-specific reference populations are projected to experience reductions in AS-MO3 concentrations by up to 0.16 ppb in Missouri in 2023 and 1.2 ppb in Arkansas in 2026. In 2023 there are also predicted to be AS-MO3 increases up to 0.06 ppb in West Virginia; these increases are very small, however, and by 2026, West Virginia is projected to experience substantially greater reductions in AS-MO3 concentrations, on the order of 0.8 ppb. In most states, populations potentially of concern are projected to experience similar AS-MO3 concentration changes as the state-level reference population.

An important limitation of this state-level analysis is that the influence of the number of people in the state is not reflected in the results, whereas the national-level results above weight air quality changes by population. For example, even though there is only a small reduction in AS-MO3 concentration from this action in California, the state's large population will contribute substantially to the national averages. Conversely, while the largest AS-MO3 concentration reductions in 2026 occur in Arkansas and Louisiana, as of 2022, they are the 34<sup>th</sup> and 25<sup>th</sup> most populated states, respectively, and will contribute less to the national population-weighted AS-MO3 information than more populated states, such as California.

Therefore, whereas ozone exposure impacts vary considerably across states, the small magnitude of differential impacts expected by the final rule is not likely to meaningfully exacerbate or mitigate EJ concerns within individual states.

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<sup>177</sup> See Section 1 of the rule preamble for a discussion of the states included in the rule and their requirements for EGUs and non-EGUs.



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State	2023 EGU																			
	Reference (0-99)	Race			Ethnicity		Linguistic Isolation		Poverty Status		Educational Attainment		Employment Status			Insurance Status		Age		
	White (0-99)	American Indian (0-99)	Asian (0-99)	Black (0-99)	Non-Hispanic (0-99)	Hispanic (0-99)	English "well or better" (0-99)	English < "well" (0-99)	<Poverty line (0-99)	>Poverty line (0-99)	More educated (>24, HS or more)	Less educated (<24, no HS)	Employed (0-99)	Unemployed (0-99)	Not in the labor force (0-99)	Insured (0-64)	Uninsured (0-64)	Children (0-17)	Adults (18-64)	Older Adults (65-99)
Alabama	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Arizona	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Arkansas	0.08	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
California	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Colorado	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Connecticut	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Delaware	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Florida	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Georgia	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Idaho	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Illinois	0.07	0.07	0.07	0.06	0.07	0.08	0.06	0.07	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Indiana	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Iowa	0.07	0.07	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Kansas	0.09	0.09	0.10	0.09	0.09	0.09	0.08	0.09	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Kentucky	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Louisiana	0.06	0.06	0.06	0.07	0.06	0.06	0.07	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Maine	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Maryland	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Massachusetts	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Michigan	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Minnesota	0.08	0.08	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.08	0.08	0.07	0.08	0.07	0.08	0.07	0.08	0.08	0.07
Mississippi	0.10	0.10	0.09	0.13	0.08	0.10	0.11	0.10	0.10	0.09	0.10	0.10	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.09
Missouri	0.14	0.14	0.12	0.16	0.15	0.14	0.13	0.14	0.14	0.13	0.14	0.13	0.14	0.14	0.14	0.14	0.13	0.14	0.14	0.14
Montana	0.01	0.01	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.00	0.01	0.01
Nebraska	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.05	0.04
Nevada	0.06	0.06	0.06	0.05	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05
New Hampshire	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
New Jersey	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
New Mexico	0.03	0.02	0.03	0.02	0.02	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02
New York	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
North Carolina	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
North Dakota	0.01	0.01	0.01	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Ohio	0.03	0.03	0.03	0.04	0.04	0.03	0.03	0.03	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.03
Oklahoma	0.14	0.14	0.13	0.15	0.14	0.14	0.14	0.15	0.14	0.14	0.14	0.13	0.14	0.14	0.13	0.14	0.13	0.14	0.14	0.13
Oregon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pennsylvania	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Rhode Island	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
South Carolina	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
South Dakota	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Tennessee	0.06	0.05	0.06	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05
Texas	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.05	0.04	0.04	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.04	0.05	0.05
Utah	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Vermont	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Virginia	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Washington	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West Virginia	-0.04	-0.04	-0.04	-0.06	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
Wisconsin	0.07	0.07	0.06	0.07	0.08	0.07	0.08	0.07	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Wyoming	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02

Figure 7-3. Heat Map of State Average AS-MO3 Ozone Concentration Reductions (Green) and Increases (Red) by Demographic Group for EGUs in 2023 (ppb)

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State	Ref. Reference (0-99)	2026 EGU+NonEGU																			
		Race			Ethnicity		Linguistic Isolation		Poverty Status		Educational Attainment		Employment Status		Insurance Status		Age				
		White (0-99)	American Indian (0-99)	Asian (0-99)	Black (0-99)	Non-Hispanic (0-99)	Hispanic (0-99)	English "well or better" (0-99)	English < "well" (0-99)	<Poverty line (0-99)	>Poverty line (0-99)	More educated (>24; HS or more) (0-99)	Less educated (>24; no HS) (0-99)	Employed (0-99)	Unemployed (0-99)	Not in the labor force (0-99)	Insured (0-64)	Uninsured (0-64)	Children (0-17)	Adults (18-64)	Older Adults (65-99)
Alabama	0.36	0.37	0.38	0.36	0.35	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Arizona	0.09	0.09	0.11	0.09	0.09	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Arkansas	1.02	0.99	0.89	0.92	1.20	1.03	0.91	1.02	0.92	1.03	1.02	1.03	1.00	1.04	1.02	1.02	1.03	0.98	1.02	1.02	1.02
California	0.11	0.11	0.11	0.11	0.11	0.10	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Colorado	0.15	0.15	0.16	0.15	0.15	0.16	0.15	0.15	0.15	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.15	0.15	0.16
Connecticut	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Delaware	0.35	0.35	0.35	0.36	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Florida	0.07	0.07	0.08	0.07	0.07	0.08	0.05	0.07	0.05	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Georgia	0.24	0.25	0.25	0.26	0.23	0.24	0.25	0.24	0.26	0.23	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Idaho	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Illinois	0.55	0.55	0.52	0.50	0.56	0.56	0.50	0.55	0.49	0.56	0.55	0.55	0.54	0.54	0.55	0.55	0.55	0.53	0.55	0.55	0.56
Indiana	0.64	0.64	0.62	0.63	0.61	0.64	0.60	0.64	0.60	0.63	0.64	0.64	0.63	0.63	0.64	0.63	0.64	0.63	0.63	0.64	0.64
Iowa	0.36	0.36	0.34	0.37	0.38	0.37	0.35	0.36	0.35	0.37	0.36	0.36	0.36	0.37	0.36	0.37	0.36	0.36	0.36	0.36	0.36
Kansas	0.53	0.53	0.58	0.54	0.55	0.54	0.51	0.53	0.50	0.54	0.53	0.54	0.53	0.55	0.53	0.54	0.53	0.53	0.53	0.53	0.53
Kentucky	0.83	0.82	0.84	0.86	0.89	0.83	0.85	0.83	0.87	0.80	0.84	0.84	0.80	0.83	0.83	0.82	0.83	0.81	0.83	0.83	0.83
Louisiana	1.02	1.02	0.90	1.03	1.04	1.02	1.03	1.02	1.02	1.01	1.03	1.03	1.00	1.03	1.02	1.02	1.03	1.01	1.02	1.03	1.02
Maine	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Maryland	0.41	0.42	0.41	0.42	0.40	0.42	0.41	0.41	0.41	0.41	0.41	0.42	0.41	0.41	0.41	0.42	0.41	0.41	0.41	0.41	0.42
Massachusetts	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16
Michigan	0.47	0.47	0.42	0.48	0.49	0.47	0.49	0.47	0.49	0.48	0.47	0.47	0.48	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Minnesota	0.22	0.22	0.17	0.23	0.23	0.22	0.23	0.22	0.23	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Mississippi	0.70	0.69	0.64	0.68	0.71	0.70	0.69	0.70	0.71	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Missouri	0.81	0.80	0.73	0.88	0.87	0.81	0.73	0.81	0.78	0.78	0.81	0.81	0.80	0.81	0.81	0.80	0.81	0.78	0.80	0.81	0.81
Montana	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Nebraska	0.26	0.26	0.24	0.28	0.28	0.26	0.26	0.26	0.27	0.27	0.26	0.26	0.26	0.27	0.26	0.26	0.27	0.26	0.26	0.27	0.26
Nevada	0.09	0.08	0.07	0.09	0.09	0.08	0.09	0.08	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.08	0.09	0.08
New Hampshire	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
New Jersey	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.30	0.29	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
New Mexico	0.17	0.16	0.24	0.16	0.16	0.18	0.16	0.17	0.15	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.18	0.17	0.17	0.17
New York	0.27	0.27	0.27	0.26	0.26	0.27	0.26	0.27	0.25	0.27	0.27	0.27	0.26	0.27	0.27	0.27	0.27	0.26	0.27	0.27	0.27
North Carolina	0.28	0.28	0.25	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
North Dakota	0.06	0.06	0.04	0.07	0.06	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.06	0.05	0.06	0.05	0.06	0.05	0.06
Ohio	0.69	0.69	0.69	0.70	0.68	0.69	0.66	0.69	0.67	0.69	0.69	0.69	0.69	0.68	0.69	0.69	0.69	0.69	0.69	0.69	0.68
Oklahoma	0.89	0.88	0.90	0.92	0.92	0.89	0.89	0.89	0.91	0.89	0.89	0.89	0.88	0.90	0.89	0.89	0.89	0.88	0.89	0.89	0.88
Oregon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pennsylvania	0.46	0.46	0.42	0.42	0.42	0.46	0.40	0.46	0.40	0.45	0.46	0.46	0.44	0.46	0.46	0.46	0.45	0.48	0.45	0.45	0.46
Rhode Island	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
South Carolina	0.20	0.20	0.20	0.20	0.19	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
South Dakota	0.14	0.14	0.10	0.15	0.16	0.14	0.14	0.14	0.17	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.13	0.14	0.14	0.13
Tennessee	0.52	0.50	0.52	0.54	0.62	0.52	0.54	0.52	0.53	0.54	0.52	0.52	0.52	0.53	0.52	0.52	0.53	0.53	0.53	0.52	0.51
Texas	0.44	0.43	0.45	0.48	0.50	0.48	0.38	0.44	0.40	0.41	0.44	0.45	0.42	0.44	0.44	0.43	0.44	0.42	0.43	0.44	0.44
Utah	0.28	0.28	0.28	0.29	0.29	0.28	0.29	0.28	0.29	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.27
Vermont	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Virginia	0.44	0.44	0.43	0.43	0.41	0.44	0.43	0.44	0.43	0.44	0.43	0.44	0.44	0.43	0.44	0.44	0.43	0.44	0.43	0.43	0.44
Washington	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West Virginia	0.83	0.84	0.83	0.85	0.80	0.84	0.77	0.83	0.76	0.84	0.83	0.83	0.82	0.84	0.83	0.83	0.84	0.82	0.83	0.83	0.83
Wisconsin	0.31	0.31	0.27	0.31	0.35	0.31	0.34	0.31	0.33	0.32	0.31	0.31	0.32	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Wyoming	0.08	0.08	0.07	0.09	0.10	0.08	0.09	0.08	0.08	0.08	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08

Figure 7-4. Heat Map of State Average AS-MO3 Ozone Concentration Reductions by Demographic Group for EGUs and Non-EGUs in 2026 (ppb)

#### 7.4.1.3 *Distributional Results*

While aggregated national- and state-level average ozone concentration results (Section 7.4.1.1) provide an overview of potential exposure differences across populations, detailed information on the distribution of AS-MO3 ozone exposures within populations, and specifically the portions of each population experiencing ozone concentration changes due to the rule, can provide a more comprehensive understanding of analytical results. Figures in this section present cumulative counts of each population exposed to ascending levels of AS-MO3 ozone concentrations across the contiguous U.S. Results allow evaluation of what percentage of each subpopulation (e.g., Hispanics) in the contiguous U.S. experience average baseline ozone concentrations at or below certain AS-MO3 ozone concentrations (e.g., 40 ppb) compared to what percentage of the overall reference group (i.e., the total population of contiguous U.S.) experiences ozone concentrations. More specifically, to permit the direct comparison of demographic populations with different absolute numbers (e.g., the large overall reference population with the much smaller number of Asians), we plot the running sum of each population as a percentage against the ozone concentration changes from NO<sub>x</sub> emissions reductions under the regulatory alternatives.

This distributional EJ analysis is also subject to additional uncertainties related to more highly resolved input parameters and additional assumptions (U.S. EPA 2021d, Section 6). For example, this analysis does not account for potential difference in underlying susceptibility, vulnerability, or risk factors across populations expected to experience post-policy AS-MO3 exposure changes. We also did not evaluate whether concentration reductions/increases occurred in areas of higher/lower baseline burden exposures. Nor could we include information about differences in other factors that could affect the likelihood of adverse impacts (e.g., exercise patterns) across groups. Therefore, this analysis should not be used to conclusively assert that there are meaningful differences in ozone exposure impacts in either the baseline or the rule across population groups.

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As the baseline scenario is similar to that of the rule, we focus on the policy-specific ozone changes of this final rulemaking.<sup>178</sup> Distributions of 12 km gridded ozone concentration reductions from NOx emissions reductions of affected facilities under the three regulatory alternatives analyzed in this final rulemaking in 2023 (EGU controls only) and 2026 (EGU and non-EGU controls, combined) are shown in Figure 7-5 and Figure 7-6, respectively. For clarity, only above/below the poverty line and those who speak English “well or better”/“less than well” are shown and sex and the overall reference group are excluded from the cumulative distribution figures.

The vast majority of ozone concentration changes are less than 0.1 ppb in 2023 and less than 1 ppb in 2026. As was observed in the national average ozone concentration analysis (Section 7.4.1.1), there are slight differences in the ozone concentration changes across population demographics and regulatory alternatives in 2023 and 2026 (Figure 7-5 and Figure 7-6, respectively). Proportionally, Hispanics, Asians, American Indians, and those linguistically isolated populations experience smaller ozone concentration reductions under the regulatory alternatives than the overall reference population in 2023, by a very small amount. Alternatively, the distribution of ozone concentration reductions for Black populations is greater than the reference population only in the smallest half of ozone concentration reductions.

The magnitude of ozone concentration reductions from affected EGU sources is estimated to be roughly 10-fold greater in 2026 compared to 2023. Approximately 90% of the overall reference population experiences a fairly linear distribution of ozone concentration reductions, although the steepness of the distribution varies by regulatory alternative and facility type.

Distributions of ozone concentration changes across population demographics and affected facility types are reasonably similar across the three regulatory alternatives, although to differing magnitudes. Individuals who identify as Hispanic, Asian, American Indian, and those linguistically isolated experience proportionally smaller ozone concentration reductions from

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<sup>178</sup> Briefly, the rule concluded that approximately 80% of the overall reference population resides in areas of AS-MO3 ozone concentrations at or less than about 45 ppb in 2023 and 2026. Most of this population experiences AS-MO3 ozone concentrations between 30-44 ppb. In contrast, the 20% of the overall reference population residing in areas of the highest baseline ozone concentrations experiences concentrations of between about 45-70 ppb.

EGU and non-EGU NOx emissions reductions under the regulatory alternatives than the overall reference population in 2026.

As such, the very small difference shown in the distributional analyses of ozone concentration changes under the various regulatory alternatives in 2023 and 2026 provides additional evidence that the final rule is not likely to meaningfully exacerbate or mitigate EJ concerns for population groups evaluated.

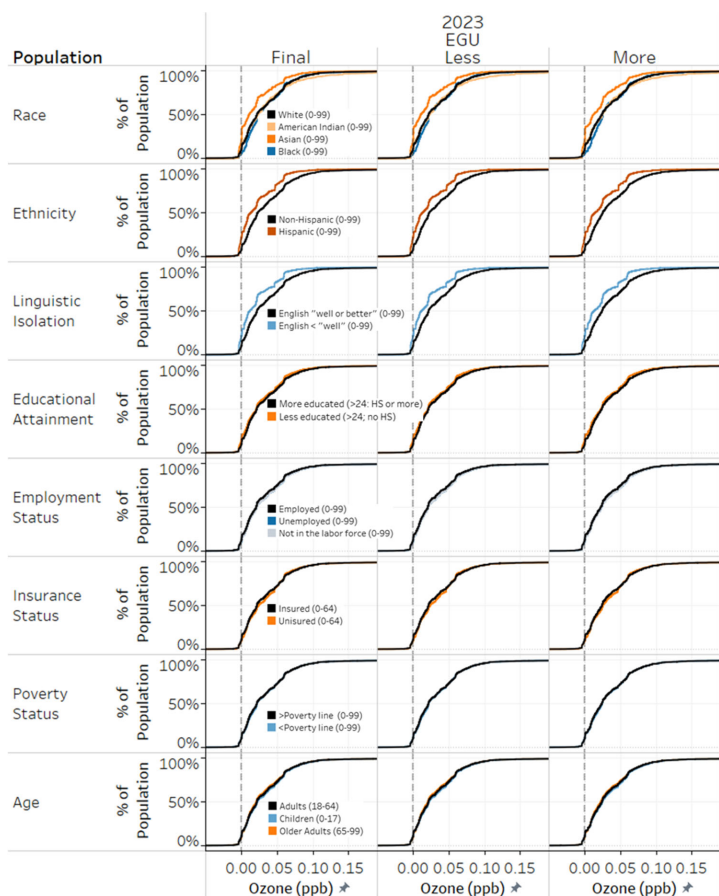
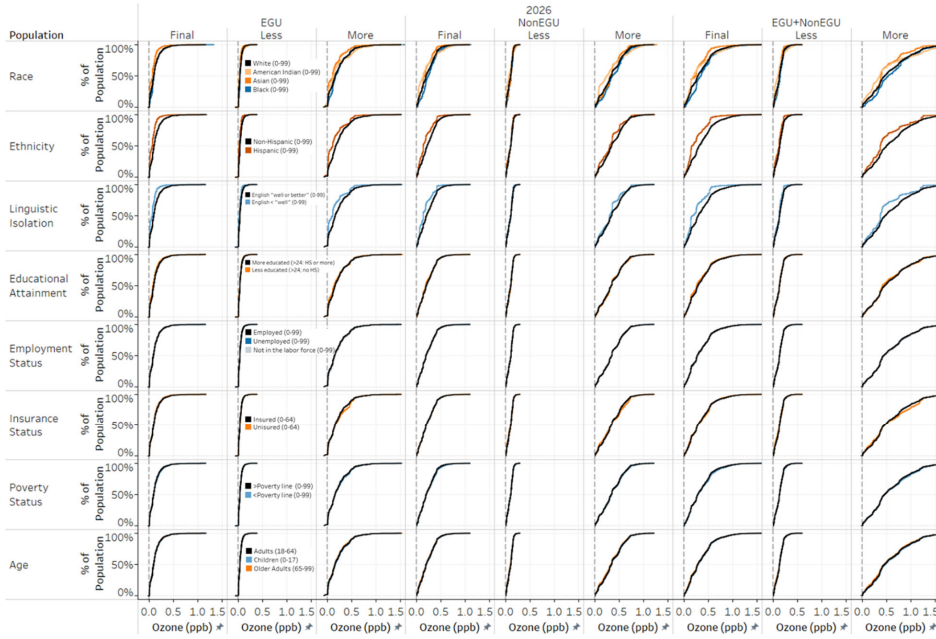


Figure 7-5. Distributions of Ozone Concentration Changes Across Populations and Regulatory Alternatives in 2023

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**Figure 7-6. Distributions of Ozone Concentration Changes Across Populations, Affected Facilities, and Regulatory Alternatives in 2026**

7.4.2 PM<sub>2.5</sub> Exposure Analysis

7.4.2.1 National Aggregated Results

While ozone is the targeted air pollutant of this final rulemaking, PM<sub>2.5</sub> reductions are a predicted co-pollutant reduction. PM<sub>2.5</sub> EJ exposure impacts of the policy options were not evaluated in the rule proposal as air quality spatial fields were unavailable. However, surfaces were developed for this final rulemaking, so PM<sub>2.5</sub> EJ impacts are provided here for EGU emission reductions in 2026.<sup>179</sup>

National average baseline PM<sub>2.5</sub> concentrations in micrograms per cubic meter (µg/m<sup>3</sup>) in 2026 are shown in the colored column labelled “baseline” the heat map in Figure 7-7.<sup>180</sup>

<sup>179</sup> Spatial fields of PM<sub>2.5</sub> concentration changes are predicted only from affected EGU sources in 2026.  
<sup>180</sup> The 2026 baseline EGU SO<sub>2</sub> and, to some extent, PM<sub>2.5</sub> emissions were notably higher in the final case compared to the proposal, especially for units in Oklahoma. In Oklahoma, annual total EGU SO<sub>2</sub> emissions in the final 2026 baseline scenario were 14,595 tons per year compared to only 2 tons per year in the proposal 2026 baseline scenario which produced unrealistically high PM<sub>2.5</sub> concentrations in Oklahoma. The unrealistic PM<sub>2.5</sub> concentrations were

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Concentrations in the “baseline” column represent the total estimated PM<sub>2.5</sub> exposure burden averaged over the 12-month calendar year and is colored to more easily visualize differences in average concentrations, with lighter blue coloring representing smaller average concentrations and darker blue coloring representing larger average concentrations. Average national disparities observed in the baseline of this rule are similar to those described by recent rules (e.g., the PM NAAQS Proposal), that is, populations with national average PM<sub>2.5</sub> concentrations higher than the reference population in 2026 ordered from most to least difference were: individuals who are linguistically isolated, Hispanic individuals, Asian individuals, Black individuals, the less educated, and children.

The three columns on the right side of Figure 7-7 provide information regarding how the final rulemaking will impact PM<sub>2.5</sub> concentrations across various populations from EGU controls under the rule, the less stringent alternative, and the more stringent alternative. Under the final rule in 2026, the difference in population-weighted seasonal average PM<sub>2.5</sub> reductions across demographic groups are relatively small and consistent.

The national-level assessment of PM<sub>2.5</sub> before and after implementation of this final rulemaking suggests that while EJ exposure disparities are present in the pre-policy scenario, meaningful EJ exposure concerns are not likely created or exacerbated by the rule for the population groups evaluated.

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removed from the spatial fields for the final rule 2026 alternatives by replacing the final rule EGU SO<sub>2</sub> and PM<sub>2.5</sub> emissions in Oklahoma with the corresponding 2026 baseline SO<sub>2</sub> and PM<sub>2.5</sub> emissions from the proposal. This impacts the magnitude of baseline PM<sub>2.5</sub> concentrations but should not impact changes due to the policy alternatives.

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Population	Group	Population Count	2026				
			-	EGU			
			Baseline	Final	Less	More	
Reference	Reference (0-99)	352M	7.34	0.01	0.00	0.04	
Race	White (0-99)	276M	7.24	0.01	0.00	0.04	
	American Indian (0-99)	4M	6.83	0.01	0.00	0.03	
	Asian (0-99)	24M	7.91	0.01	0.00	0.03	
	Black (0-99)	49M	7.64	0.02	0.00	0.04	
Ethnicity	Non-Hispanic (0-99)	279M	7.13	0.01	0.00	0.04	
	Hispanic (0-99)	73M	8.13	0.01	0.00	0.03	
Linguistic	English "well or better" (0-99)	336M	7.30	0.01	0.00	0.04	
Isolation	English < "well" (0-99)	16M	8.26	0.01	0.00	0.03	
Poverty	>Poverty line (0-99)	296M	7.31	0.01	0.00	0.04	
Status	<Poverty line (0-99)	55M	7.52	0.01	0.00	0.04	
Educational	More educated (>24: HS or more)	207M	7.24	0.01	0.00	0.04	
	Less educated (>24; no HS)	34M	7.67	0.01	0.00	0.04	
Employment	Employed (0-99)	9M	7.49	0.01	0.00	0.04	
	Status	Unemployed (0-99)	352M	7.34	0.01	0.00	0.04
		Not in the labor force (0-99)	179M	7.34	0.01	0.00	0.04
Insurance	Insured (0-64)	255M	7.38	0.01	0.00	0.04	
	Status	Uninsured (0-64)	31M	7.47	0.01	0.00	0.04
Age	Children (0-17)	80M	7.41	0.01	0.00	0.04	
	Adults (18-64)	206M	7.38	0.01	0.00	0.04	
	Older Adults (65-99)	67M	7.12	0.01	0.00	0.04	
Sex	Females (0-99)	178M	7.35	0.01	0.00	0.04	
	Males (0-99)	174M	7.33	0.01	0.00	0.04	

**Figure 7-7. Heat Map of the National Average PM<sub>2.5</sub> Concentrations in the Baseline and Reductions in Concentrations Due to this Rulemaking Across Demographic Groups in 2026 (µg/m<sup>3</sup>)**

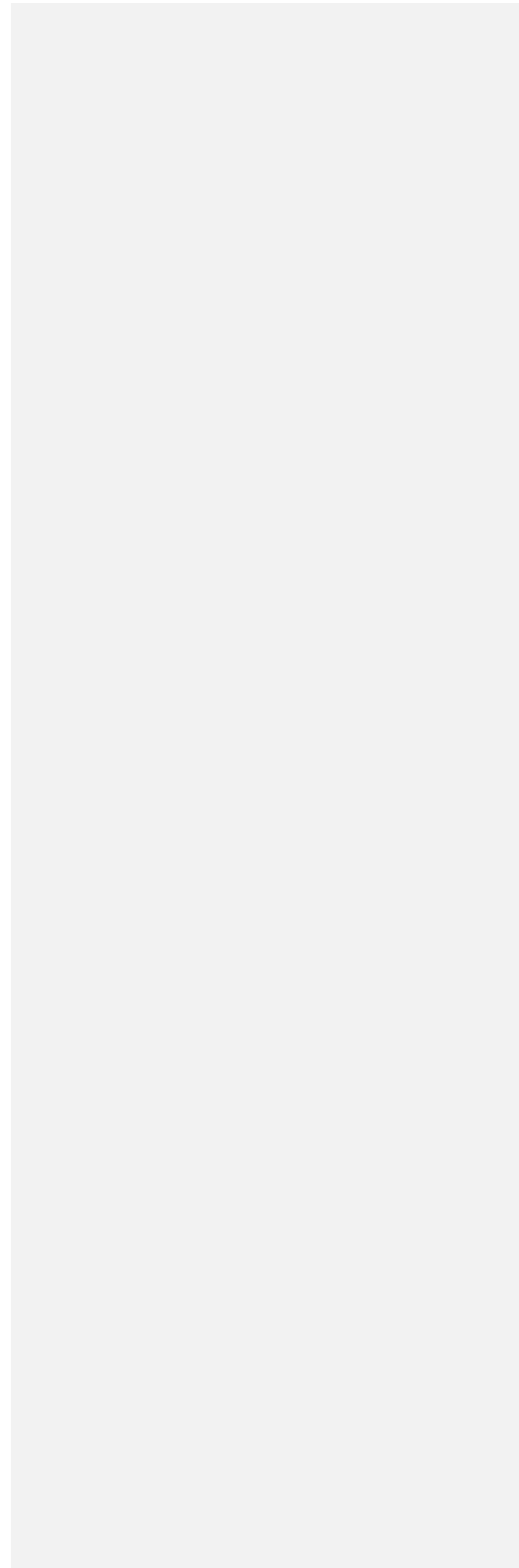
#### 7.4.2.2 State Aggregated Results

We also provide PM<sub>2.5</sub> concentration reductions by state and demographic population in 2026 for the 48 states in the contiguous U.S, for the policy scenario only. In this heat map darker blue again indicates larger PM<sub>2.5</sub> reductions, with demographic groups shown as columns and each state as a row. On average, the state-specific reference populations are projected to experience reductions in PM<sub>2.5</sub> concentrations by up to 0.07 µg/m<sup>3</sup> in Arkansas and Louisiana. In all 48 states, populations potentially of concern are projected to experience similar PM<sub>2.5</sub> concentration reductions as the state-level reference population. Please note that population counts vary greatly by state, and that averaging results of the 48 states shown here will not reflect national population-weighted exposure estimates.



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Therefore, whereas PM<sub>2.5</sub> exposure impacts vary considerably across states, the small magnitude of differential impacts expected by the final rule is not likely to meaningfully exacerbate or mitigate EJ concerns within individual states.



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State	EGU 2026																					
	Ref..	Race				Ethnicity		Linguistic Isolation	Poverty Status		Educational Attainment		Employment Status		Insurance Status		Age					
	Reference (0-99)	White (0-99)	American Indian (0-99)	Asian (0-99)	Black (0-99)	Non-Hispanic (0-99)	Hispanic (0-99)	English "well or better" (0-99)	English < "well" (0-99)	<Poverty line (0-99)	>Poverty line (0-99)	More educated (>24, HS or more)	Less educated (<24, no HS)	Employed	Unemployed	Not in the labor force	Insured	Uninsured	Children (0-17)	Adults (18-64)	Older Adults (65-99)	
Alabama	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Arizona	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Arkansas	0.06	0.06	0.06	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
California	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Colorado	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Connecticut	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delaware	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Florida	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Georgia	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Idaho	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Illinois	0.02	0.02	0.02	0.01	0.02	0.02	0.01	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Indiana	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Iowa	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Kansas	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Kentucky	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Louisiana	0.06	0.06	0.06	0.06	0.07	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Maine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maryland	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Massachusetts	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Michigan	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Minnesota	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Mississippi	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Missouri	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Montana	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nebraska	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Nevada	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New Hampshire	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New Jersey	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New Mexico	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New York	0.01	0.01	0.00	0.00	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01
North Carolina	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
North Dakota	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ohio	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Oklahoma	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Oregon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pennsylvania	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Rhode Island	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
South Carolina	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
South Dakota	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tennessee	0.03	0.02	0.02	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02
Texas	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Utah	0.02	0.02	0.01	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.02	0.02	0.02	0.01
Vermont	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Virginia	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Washington	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
West Virginia	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Wisconsin	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Wyoming	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 7-8. Heat Map of State Average PM<sub>2.5</sub> Concentration Reductions by Demographic Group for EGUs and Non-EGUs in 2026 (µg/m<sup>3</sup>)

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#### 7.4.2.3 Distributional Results

We also present cumulative counts of each population exposed to ascending levels of PM<sub>2.5</sub> concentration changes across the contiguous U.S. Results allow evaluation of what percentage of each subpopulation (e.g., Hispanics) in the contiguous U.S. experience what change in PM<sub>2.5</sub> concentrations compared to what percentage of the overall reference group (i.e., the total population of contiguous U.S.) experiences similar concentration changes from EGU emission reductions under the three regulatory alternatives in 2026.

This distributional EJ analysis is also subject to additional uncertainties related to more highly resolved input parameters and additional assumptions (U.S. EPA 2021d, Section 6). For example, this analysis does not account for potential difference in underlying susceptibility, vulnerability, or risk factors across populations to PM<sub>2.5</sub> exposure. Nor could we include information about differences in other factors that could affect the likelihood of adverse impacts (e.g., exercise patterns) across groups. Therefore, this analysis should not be used to assert that there are meaningful differences in PM<sub>2.5</sub> exposures associated with either the baseline or the rule.

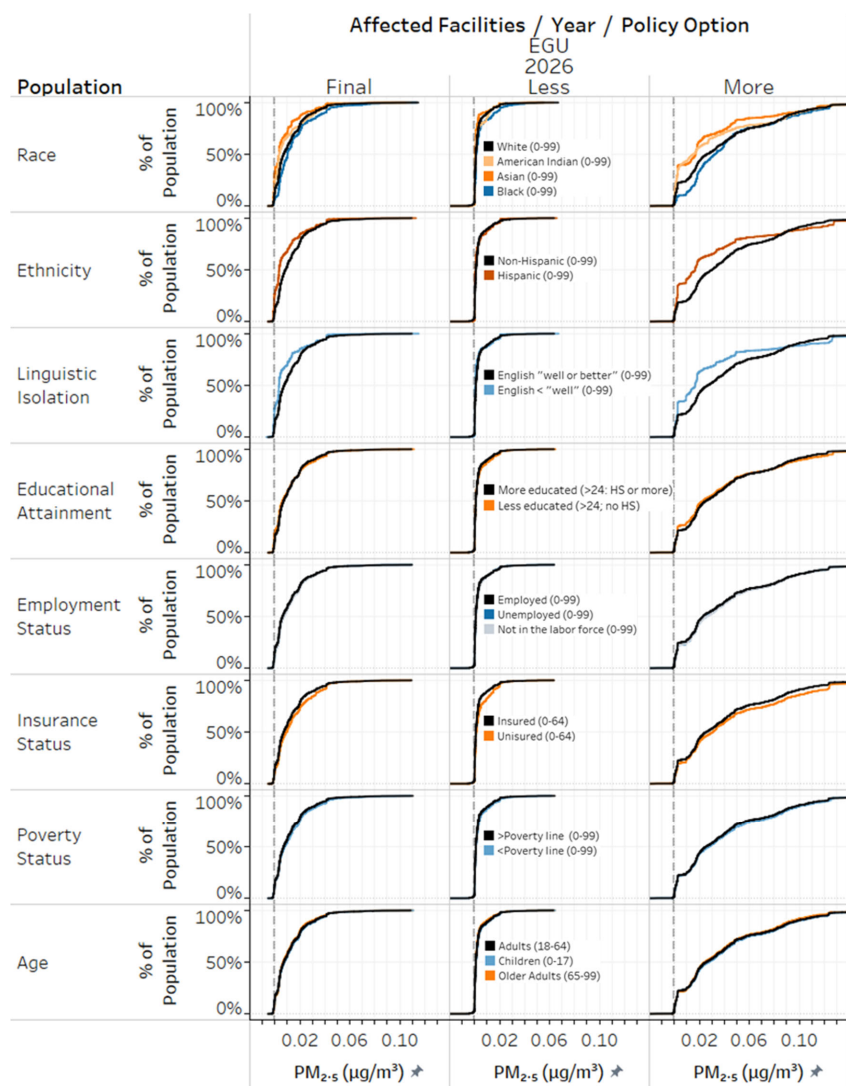
As the baseline scenario is similar to that described by other RIAs, we focus on the PM<sub>2.5</sub> changes due to this final rulemaking. Distributions of 12 km gridded PM<sub>2.5</sub> concentration reductions from EGU control strategies of affected facilities under the three regulatory alternatives analyzed in this final rulemaking in 2026 are shown in Figure 7-9. For clarity, only above/below the poverty line and those who speak English “well or better”/“less than well” are shown and sex and the overall reference group are excluded from the cumulative distribution figures.

The vast majority of PM<sub>2.5</sub> concentration changes are less than 0.1 µg/m<sup>3</sup> in 2026. As was observed in the national average PM<sub>2.5</sub> concentration analysis (Section 7.4.2.1), there are slight differences in the PM<sub>2.5</sub> concentration changes across population demographics and regulatory alternatives in 2026 (Figure 7-9).

Distributions of PM<sub>2.5</sub> concentration changes across population demographics are reasonably similar across the three regulatory alternatives, although to differing magnitudes. As such, the very small difference shown in the distributional analyses of PM<sub>2.5</sub> concentration changes under the various regulatory alternatives in 2026 provides additional evidence that the

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final rule is not likely to meaningfully exacerbate or mitigate EJ concerns for population groups evaluated.



**Figure 7-9. Distributions of PM<sub>2.5</sub> Concentration Changes Across Populations, Affected Facilities, and Regulatory Alternatives in 2026**

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#### 7.4.2.4 Qualitative Assessment of PM<sub>2.5</sub> Health Impacts

Health studies have shown a significant association between exposure to particle pollution and health risks, including premature death (U.S. EPA 2019 and Chapter 5). PM<sub>2.5</sub> reductions are expected from this action, but demographic-specific health impacts were not assessed for baseline or regulatory alternatives under this rulemaking, due to the small magnitude of predicted changes. However, in general, both recent publications and analyses by the EPA suggest that the burden of PM<sub>2.5</sub> exposures and impacts may disproportionately affect certain groups, such as Black and Hispanic populations (e.g., Bell 2012, Bravo 2016, Kelly 2021, U.S. EPA 2020, U.S. EPA 2021a, U.S. EPA 2021c).

### 7.5 Qualitative Assessment of CO<sub>2</sub>

In 2009, under the *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act* (“Endangerment Finding”), the Administrator considered how climate change threatens the health and welfare of the U.S. population. As part of that consideration, she also considered risks to minority and low-income individuals and communities, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially disadvantaged communities; individuals at vulnerable lifestages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; the disabled; those experiencing homelessness, mental illness, or substance abuse; and/or Indigenous or minority populations dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the U.S. Global Change Research Program (USGCRP),<sup>181,182</sup> the Intergovernmental Panel on Climate Change

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<sup>181</sup> 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.

<sup>182</sup> 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. <http://dx.doi.org/10.7930/J0R49NQX>

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(IPCC),<sup>183,184,185,186</sup> and the National Academies of Science, Engineering, and Medicine<sup>187,188</sup> add more evidence that the impacts of climate change raise potential environmental justice concerns. These reports conclude that poorer or predominantly non-White communities can be especially vulnerable to climate change impacts because they tend to have limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the United States. In particular, the 2016 scientific assessment on the *Impacts of Climate Change on Human Health*<sup>189</sup> found with high confidence that vulnerabilities are place- and time-specific, lifestages and ages are linked to immediate and future health impacts, and social determinants of health are linked to greater extent and severity of climate change-related health impacts.

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<sup>183</sup> Oppenheimer, M., M. Campos, R. Warren, J. Birkmann, G. Luber, B. O'Neill, and K. Takahashi, 2014: Emergent risks and key vulnerabilities. In: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1039-1099.

<sup>184</sup> Porter, J.R., L. Xie, A.J. Challinor, K. Cochrane, S.M. Howden, M.M. Iqbal, D.B. Lobell, and M.I. Travasso, 2014: Food security and food production systems. In: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 485-533.

<sup>185</sup> Smith, K.R., A. Woodward, D. Campbell-Lendrum, D.D. Chadee, Y. Honda, Q. Liu, J.M. Olwoch, B. Revich, and R. Sauerborn, 2014: Human health: impacts, adaptation, and co-benefits. In: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 709-754.

<sup>186</sup> IPCC, 2018: Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. In Press.

<sup>187</sup> National Research Council. 2011. *America's Climate Choices*. Washington, DC: The National Academies Press. <https://doi.org/10.17226/12781>.

<sup>188</sup> National Academies of Sciences, Engineering, and Medicine. 2017. *Communities in Action: Pathways to Health Equity*. Washington, DC: The National Academies Press. <https://doi.org/10.17226/24624>.

<sup>189</sup> USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*

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In a 2021 report, EPA considered the degree to which four socially vulnerable populations—defined based on income, educational attainment, race and ethnicity, and age—may be more exposed to the highest impacts of climate change.<sup>190</sup> The report found that Black and African American populations are approximately 40% more likely to live in areas of the U.S. projected to experience the highest increases in mortality rates due to changes in extreme temperatures. Additionally, Hispanic and Latino individuals in weather-exposed industries were found to be 43% more likely to currently live in areas with the highest projected labor hour losses due to extreme temperatures. American Indian and Alaska Native individuals are projected to be 48% more likely to currently live in areas where the highest percentage of land may be inundated by sea level rise. Overall, the report confirmed findings of broader climate science assessments that Americans identifying as people of color, those with low-income, and those without a high school diploma face disproportionate risks of experiencing the most damaging impacts of climate change.

These findings suggest that CO<sub>2</sub> reductions may benefit disproportionately impacted populations. However, as we have not conducted the wide-ranging analyses that would be needed to assess the specific impacts of this rule on the multiple climate-EJ interactions described above, we cannot analyze the potential impacts of the final rule quantitatively.

## **7.6 Summary**

As with all EJ analyses, data limitations make it quite possible that disparities may exist that our analysis did not identify. This is especially relevant for potential EJ characteristics, environmental impacts, and more granular spatial resolutions that were not evaluated. For example, here we provide a quantitative EJ assessment of ozone and PM<sub>2.5</sub> concentration changes from this rule but can only qualitatively discuss EJ impacts of CO<sub>2</sub> emission reductions. Therefore, this analysis is only a partial representation of the distributions of potential impacts. Additionally, EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, so results similar to those presented here should not be assumed for other rulemakings.

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<sup>190</sup> [U.S. EPA 2021c, EPA](#)– Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430-R-21-003.

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For the rule, we quantitatively evaluate the proximity of affected facilities to potentially disadvantaged populations for consideration of local pollutants impacted by this rule but not modeled here (Section 7.3). We also quantitatively evaluate the potential for disproportionate pre- and policy-policy ozone and PM<sub>2.5</sub> exposures 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 provide information as to whether there may be potential EJ concerns associated with environmental stressors, in this case, local NO<sub>2</sub> emitted from sources affected by the regulatory action for certain population groups of (Section 7.3). The baseline demographic proximity analyses suggest that larger percentages of Hispanic individuals, African American individuals, 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 American individuals, 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, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (e.g., NO<sub>2</sub>) for certain population groups of concern in the baseline (question 1). 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 should not be interpreted as a direct measure of exposure or impact.

While the demographic proximity analyses may appear to parallel the baseline analysis of nationwide ozone and PM<sub>2.5</sub> exposures in certain ways, the two should not be directly compared. The baseline ozone and PM<sub>2.5</sub> exposure assessments are in effect an analysis of total burden in the contiguous U.S., and include various assumptions, such as the implementation of promulgated regulations. It serves as a starting point for both the estimated ozone and PM<sub>2.5</sub> changes due to this rule as well as a snapshot of air pollution concentrations in the near future.

The baseline ozone and PM<sub>2.5</sub> exposure analyses respond to question 1 from EPA's EJ Technical Guidance document more directly than the proximity analyses, as they evaluate a form of the environmental stressor primarily affected by the regulatory action (Section 7.4). Baseline



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ozone and PM<sub>2.5</sub> exposure analyses show that certain populations, such as Hispanic individuals, Asian individuals, those linguistically isolated, those less educated, and children may experience disproportionately higher ozone and PM<sub>2.5</sub> exposures as compared to the national average. Individuals who identify as American Indian may also experience disproportionately higher ozone concentrations than the reference group. Therefore, there likely are potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline.

Finally, we evaluate how post-policy regulatory alternatives of this final rulemaking are expected to differentially impact demographic populations, informing questions 2 and 3 from EPA’s EJ Technical Guidance with regard to ozone and PM<sub>2.5</sub> exposure changes. We infer that disparities in the ozone and PM<sub>2.5</sub> concentration burdens are likely to remain after implementation of the regulatory action or alternatives under consideration due to the small magnitude of the concentration changes associated with this rulemaking across demographic populations relative to baseline burden disparities (question 2). Also, due to the very small differences observed in the distributional analyses of post-policy ozone and PM<sub>2.5</sub> exposure impacts across populations, we do not find evidence that potential EJ concerns related to ozone or PM<sub>2.5</sub> exposures will be meaningfully exacerbated or mitigated in the regulatory alternatives under consideration, compared to the baseline (question 3). Importantly, the action described in this rule is expected to lower ozone and PM<sub>2.5</sub> in many areas, including those areas that struggle to attain or maintain the ozone NAAQS, and thus mitigate some pre-existing health risks across all populations evaluated.

This EJ air quality analysis concludes that there are disparities across various populations in the pre-policy baseline scenario (EJ question 1) and infer that these disparities are likely to persist after promulgation of this final rulemaking (EJ question 2). This EJ assessment also suggests that this action will neither mitigate nor exacerbate disparities across populations of EJ concern analyzed (EJ question 3) at the national scale in a meaningful way.

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## **CHAPTER 8: COMPARISON OF BENEFITS AND COSTS**

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### **Overview**

The EPA performed an analysis to estimate the costs and benefits of compliance with the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS) and more and less stringent alternatives.

Consistent with OMB Circular A-4 and EPA’s *Guidelines for Preparing Economic Analyses* (2010), this RIA presents the benefits and costs of the final rule from 2023 through 2042. The estimated health benefits are expected to arise from reduced PM<sub>2.5</sub> and ozone concentrations, and the estimated climate benefits are from reduced greenhouse gas (GHG) emissions. The estimated costs for EGUs are the costs of installing and operating controls and the increased costs of producing electricity. The estimated costs for non-EGUs are the costs of installing and operating controls to meet the ozone season emissions limits. The estimated costs for non-EGUs do not include monitoring, recordkeeping, reporting, or testing costs. Unquantified benefits and costs are described qualitatively.

The more and less stringent alternatives differ from the final rule in that they set different NO<sub>x</sub> ozone season emission budgets for the affected EGUs and different dates for compliance with the backstop emission rate. All three scenarios use emission budgets that were developed using uniform control stringency represented by \$1,800 per ton of NO<sub>x</sub> (2016\$) in 2023 and \$11,000 per ton of NO<sub>x</sub> (2016\$) in 2026. The final rule and less-stringent alternative defer the backstop emission rate for certain EGUs until the 2030 run year,<sup>191</sup> while the more stringent alternative imposes the backstop emission rate in the 2025 run year (reflective of imposition in the 2026 calendar year). The backstop emission rate is imposed beginning in the relevant run

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<sup>191</sup> IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. For this analysis, IPM maps the calendar year 2023 to run year 2023, calendar years 2024-2026 to run year 2025 and calendar years 2027-2029 to run year 2028. For model details, please see Chapter 2 of the IPM documentation, available at: <https://www.epa.gov/system/files/documents/2021-09/epa-platform-v6-summer-2021-reference-case-09-11-21-v6.pdf>

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year (2025 or 2030, depending on scenario), on all coal units within the 19-state region that are greater than 100 MW and lack SCR controls (excepting circulating fluidized bed (CFB) units).<sup>192</sup>

The rule also includes NO<sub>x</sub> emissions limitations with an initial compliance date of 2026 applicable to certain non-EGU stationary sources in 20 states. The rule establishes NO<sub>x</sub> emissions limitations during the ozone season for the following unit types: 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 or incinerators in Solid Waste Combustors or Incinerators.

In order to implement the OMB Circular A-4 guidance for fulfilling Executive Order (E.O.) 12866 to assess one less stringent and one more stringent alternative to the rule, we analyzed a less stringent non-EGU alternative that would require less stringent control technologies for the reciprocating internal combustion engines in Pipeline Transportation of Natural Gas and 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. We analyzed a more stringent non-EGU alternative that would require more stringent control technologies for the kilns in Cement and Concrete Products Manufacturing, the furnaces in Glass and Glass Products Manufacturing, and the natural gas-fired 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. A summary of the emissions limits can be found in Section I.B. of the preamble.

## **8.1 Results**

This RIA evaluates how EGUs and non-EGUs covered by the rule are expected to reduce their emissions in response to the requirements and flexibilities provided by the remedy implemented by the Transport FIP for the 2015 ozone NAAQS and the benefits, costs, and

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<sup>192</sup> The 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.

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impacts of their expected compliance behavior. This chapter summarizes these results. Table 8-1 shows the ozone season NO<sub>x</sub> emissions reductions expected from the rule as well as the more and less stringent alternatives analyzed from 2023 through 2030, and for 2035 and 2042. In addition, Table 8-1 shows the ozone season and annual NO<sub>x</sub>, as well as annual SO<sub>2</sub>, PM<sub>2.5</sub>, and CO<sub>2</sub> emissions reductions expected nationwide from the rule as well as the more and less stringent alternatives analyzed from 2023 through 2027, and for 2030, 2035 and 2042.

Table 8-2 below provides a summary of the 2019 ozone season emissions for non-EGUs for the 20 states subject to the Transport FIP for the 2015 ozone NAAQS in 2026, along with the estimated ozone season reductions for the rule and the less and more stringent alternatives.

For 2023, total ozone season NO<sub>x</sub> emissions reductions of 10,000 tons are from EGUs; for 2026 total ozone season NO<sub>x</sub> emissions reductions of 720,000 tons are from EGUs and non-EGUs, and for 2030 total ozone season NO<sub>x</sub> emissions reductions of 8179,000 tons are from EGUs and non-EGUs.

**Table 8-1. EGU Ozone Season NO<sub>x</sub> Emissions Changes and Annual Emissions Changes for NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, and CO<sub>2</sub> for the Regulatory Control Alternatives from 2023 - 2042**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>2023</b>			
NO <sub>x</sub> (ozone season)	10,000	10,000	10,000
NO <sub>x</sub> (annual)	15,000	15,000	15,000
SO <sub>2</sub> (annual)*	1,000	3,000	1,000
CO <sub>2</sub> (annual, thousand metric)	-	-	-
PM <sub>2.5</sub> (annual)	-	-	-
<b>2024</b>			
NO <sub>x</sub> (ozone season)	21,000	10,000	33,000
NO <sub>x</sub> (annual)	25,000	15,000	57,000
SO <sub>2</sub> (annual)	19,000	5,000	59,000
CO <sub>2</sub> (annual, thousand metric)	10,000	4,000	20,000
PM <sub>2.5</sub> (annual)	1,000	-	1,000
<b>2025</b>			
NO <sub>x</sub> (ozone season)	32,000	10,000	56,000
NO <sub>x</sub> (annual)	35,000	15,000	99,000
SO <sub>2</sub> (annual)	38,000	7,000	118,000
CO <sub>2</sub> (annual, thousand metric)	21,000	8,000	40,000
PM <sub>2.5</sub> (annual)	2,000	1,000	2,000
<b>2026</b>			
NO <sub>x</sub> (ozone season)	25,000	8,000	49,000
NO <sub>x</sub> (annual)	29,000	12,000	88,000
SO <sub>2</sub> (annual)	29,000	5,000	104,000

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	Final Rule	Less Stringent Alternative	More Stringent Alternative
CO <sub>2</sub> (annual, thousand metric)	16,000	6,000	34,000
PM <sub>2.5</sub> (annual)	1,000	-	2,000
<b>2027</b>			
NOx (ozone season)	19,000	6,000	43,000
NOx (annual)	22,000	9,000	78,000
SO <sub>2</sub> (annual)	21,000	4,000	91,000
CO <sub>2</sub> (annual, thousand metric)	10,000	3,000	28,000
PM <sub>2.5</sub> (annual)	1,000	-	2,000
<b>2030</b>			
NOx (ozone season)	34,000	33,000	31,000
NOx (annual)	62,000	59,000	50,000
SO <sub>2</sub> (annual)	93,000	98,000	51,000
CO <sub>2</sub> (annual, thousand metric)	26,000	23,000	8,000
PM <sub>2.5</sub> (annual)	1,000	1,000	-
<b>2035</b>			
NOx (ozone season)	29,000	30,000	27,000
NOx (annual)	46,000	46,000	41,000
SO <sub>2</sub> (annual)	21,000	19,000	15,000
CO <sub>2</sub> (annual, thousand metric)	16,000	15,000	8,000
PM <sub>2.5</sub> (annual)	1,000	1,000	-
<b>2042</b>			
NOx (ozone season)	22,000	22,000	22,000
NOx (annual)	23,000	22,000	21,000
SO <sub>2</sub> (annual)	15,000	15,000	7,000
CO <sub>2</sub> (annual, thousand metric)	9,000	8,000	4,000
PM <sub>2.5</sub> (annual)	-	-	-

**Table 8-2. Non-EGU Ozone Season NO<sub>x</sub> Emissions and Emissions Reductions for the Final Rule and the Less and More Stringent Alternatives**

State	2019 Ozone Season Emissions <sup>a</sup>	Final Rule – Ozone Season NO <sub>x</sub> Reductions	Less Stringent – Ozone Season NO <sub>x</sub> Reductions	More Stringent – Ozone Season NO <sub>x</sub> 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
NJ	2,078	242	242	258
NV	2,544	0	0	0

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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
<b>Totals</b>	<b>302,425</b>	<b>44,616</b>	<b>16,786</b>	<b>67,728</b>

<sup>a</sup> 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.

As shown in Chapter 4, the estimated annual compliance costs to implement the rule, as described in this RIA, are approximately \$57 million in 2023 and \$570 million in 2026 (2016\$). This RIA uses compliance costs as a proxy for social costs as mentioned in Chapter 4. As shown in Chapter 5, the estimated monetized health benefits from reduced PM<sub>2.5</sub> and ozone concentrations from implementation of the rule are approximately \$100 and \$820 million in 2023 (2016\$, based on a real discount rate of 3 percent). As shown in Chapter 5, the estimated monetized climate benefits from reduced GHG emissions are approximately \$5 million in 2023 (2016\$, based on a real discount rate of 3 percent). For 2026, the estimated monetized health benefits from implementation of the rule are approximately \$3,200 and \$14,000 million (2016\$, based on a real discount rate of 3 percent). The estimated monetized climate benefits from reduced GHG emissions are approximately \$830 million in 2026 (2016\$, based on a real discount rate of 3 percent).

The EPA calculates the monetized net benefits of the rule by subtracting the estimated monetized compliance costs from the estimated monetized health and climate benefits in 2023, 2026, and 2030. The benefits include those to public health associated with reductions in PM<sub>2.5</sub> and ozone concentrations, as well as those to climate associated with reductions in GHG emissions. The annual monetized net benefits of the rule in 2023 (in 2016\$) are approximately \$48 and \$760 million using a 3 percent real discount rate. The annual monetized net benefits of the rule in 2026 are approximately \$3,700 and \$14,000 million using a 3 percent real discount rate. The annual monetized net benefits of the rule in 2030 are approximately \$3,600 and \$15,000 million using a 3 percent real discount rate. Table 8-3 presents a summary of the monetized health and climate benefits, costs, and net benefits of the rule and the more and less



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stringent alternatives for 2023. Table 8-4 presents a summary of these impacts for the rule and the more and less stringent alternatives for 2026.

Table 8-5 presents a summary of these impacts for the rule and the more and less stringent alternatives for 2030. 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 8-3. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2023 for the U.S. (millions of 2016\$)** <sup>a,b,c</sup>

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>Health Benefits<sup>c</sup></b>	\$100 and \$820	\$100 and \$810	\$110 and \$840
<b>Climate Benefits</b>	\$5	\$4	\$5
<b>Total Benefits</b>	\$100 and \$820	\$100 and \$820	\$110 and \$840
<b>Costs<sup>d</sup></b>	\$57	\$56	\$49
<b>Net Benefits</b>	<b>\$48 and \$760</b>	<b>\$48 and \$760</b>	<b>\$66 and \$800</b>

<sup>a</sup> 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.

<sup>b</sup> Rows may not appear to add correctly due to rounding.

<sup>c</sup> The 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%.

<sup>d</sup> The costs presented in this table are 2023 annual estimates for each alternative analyzed. For EGU's, an NPV of costs was calculated using a 3.76% 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.](#)

**Table 8-4. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2026 for the U.S. (millions of 2016\$)** <sup>a,b,c</sup>

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>Health Benefits<sup>c</sup></b>	\$3,200 and \$14,000	\$950 and \$4,600	\$8,300 and \$29,000
<b>Climate Benefits</b>	\$1,100	\$420	\$2,100
<b>Total Benefits</b>	\$4,300 and \$15,000	\$1,400 and \$5,000	\$10,000 and \$31,000
<b>Costs<sup>d</sup></b>	\$570	\$110	\$2,100
<b>Net Benefits</b>	<b>\$3,700 and \$14,000</b>	<b>\$1,300 and \$4,900</b>	<b>\$8,300 and \$29,000</b>

<sup>a</sup> 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.

<sup>b</sup> Rows may not appear to add correctly due to rounding.

<sup>c</sup> The 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%.

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<sup>d</sup> 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% 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.](#)

**Table 8-5. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2030 for the U.S. (millions of 2016\$) <sup>a,b,c</sup>**

	Final Rule	Less Stringent Alternative	More Stringent Alternative
<b>Health Benefits<sup>c</sup></b>	\$3,400 and \$15,000	\$1,000 and \$4,900	\$9,000 and \$31,000
<b>Climate Benefits</b>	\$1,500	\$1,300	\$500
<b>Total Benefits</b>	\$4,900 and \$16,000	\$2,300 and \$6,200	\$9,500 and \$31,000
<b>Costs<sup>d</sup></b>	\$1,300	\$920	\$2,100
<b>Net Benefits</b>	<b>\$3,600 and \$15,000</b>	<b>\$1,400 and \$5,300</b>	<b>\$7,400 and \$29,000</b>

<sup>a</sup> 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.

<sup>b</sup> Rows may not appear to add correctly due to rounding.

<sup>c</sup> The 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%.

<sup>d</sup> 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% 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.](#)

As part of fulfilling analytical guidance with respect to E.O. 12866, the EPA presents estimates of the present value (PV) of the monetized benefits and costs over the twenty-year period 2023 to 2042. To calculate the present value of the social net-benefits of the rule, annual benefits and costs are discounted to 2023 at 3 percent and 7 discount rates as recommended by OMB’s Circular A-4. The EPA also presents the equivalent annualized value (EAV), which represents a flow of constant annual values that, had they occurred in each year from 2023 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates mentioned earlier in the RIA. Table 8-6 below includes the undiscounted streams of health benefits, climate benefits, costs, and net benefits from 2023 to 2042. Table 8-7 below provides the comparison of benefits and costs in PV and EAV terms for the rule. Estimates in the table are presented as rounded values. For the twenty-year period of 2023 to 2042, the PV of the net benefits, in 2016\$ and discounted to 2023, is \$200,000 million when using a 3 percent discount rate and \$1430,000 million when using a 7 percent discount rate. The EAV is \$13,000 million per year when using a 3 percent discount rate and \$12,000 million when using a 7 percent discount rate.

**Commented [EPA77]:** Added table note to tables 8-3, 8-4, and 8-5 to be consistent with the Executive Summary above and with the preamble.

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**Table 8-6. Undiscounted Streams Health Benefits, Climate Benefits, Costs, and Net Benefits for 2023 – 2042 (millions of 2016\$)**

	Health Benefits <sup>a</sup>		Climate Benefits <sup>b</sup>	Costs	Net Benefits	
	3%	7%	3%		3%	7%
2023	\$820	\$730	\$5	\$57	\$770	\$680
2024	\$840	\$750	\$1,100	(\$5)	\$1,400	\$1,300
2025	\$9,100	\$8,100	\$1,100	(\$5)	\$10,000	\$9,200
2026	\$14,000	\$12,000	\$1,100	\$570	\$14,000	\$12,000
2027	\$14,000	\$13,000	\$260	\$600	\$14,000	\$13,000
2028	\$14,000	\$12,000	\$270	\$600	\$14,000	\$12,000
2029	\$14,000	\$13,000	\$270	\$600	\$14,000	\$13,000
2030	\$15,000	\$13,000	\$1,500	\$1,300	\$15,000	\$13,000
2031	\$15,000	\$13,000	\$1,500	\$1,300	\$15,000	\$13,000
2032	\$15,000	\$14,000	\$960	\$1,400	\$15,000	\$14,000
2033	\$15,000	\$14,000	\$980	\$1,400	\$15,000	\$14,000
2034	\$16,000	\$14,000	\$1,000	\$1,400	\$16,000	\$14,000
2035	\$16,000	\$14,000	\$1,000	\$1,400	\$16,000	\$14,000
2036	\$16,000	\$15,000	\$1,000	\$1,400	\$16,000	\$15,000
2037	\$17,000	\$15,000	\$1,000	\$1,400	\$17,000	\$15,000
2038	\$17,000	\$15,000	\$1,300	\$1,400	\$17,000	\$15,000
2039	\$17,000	\$15,000	\$1,400	\$1,400	\$17,000	\$15,000
2040	\$17,000	\$15,000	\$1,400	\$1,400	\$17,000	\$15,000
2041	\$17,000	\$16,000	\$1,400	\$1,400	\$17,000	\$16,000
2042	\$18,000	\$16,000	\$1,400	\$1,400	\$18,000	\$16,000

<sup>a</sup> We assume that there is a cessation lag between the change in exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to exposures occur in a distributed fashion over the 20 years following exposure, which affects the valuation of mortality benefits at different discount rates. The table reflects the benefits associated with the higher of the two point estimates from two different epidemiologic studies. We present the benefits calculated at real discount rates of 3 and 7 percent.

<sup>b</sup> We include the climate benefits calculated at a 3 percent discount rate.

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**Table 8-7. Summary of Present Values and Equivalent Annualized Values for the 2023-2042 Timeframe for Estimated Monetized Compliance Costs, Benefits, and Net Benefits for the Final Rule (millions of 2016\$, discounted to 2023)<sup>a,b</sup>**

	Health Benefits		Climate Benefits		Cost <sup>c</sup>		Net Benefits	
	3%	7%	3%	3%	7%	3%	7%	
2023	\$820	\$730	\$5	\$57	\$57	\$770	\$680	
2024	\$810	\$700	\$1,000	(\$5)	(\$5)	\$1,300	\$1,200	
2025	\$8,600	\$7,100	\$1,000	(\$5)	(\$4)	\$9,600	\$8,100	
2026	\$13,000	\$10,000	\$1,000	\$520	\$460	\$13,000	\$10,000	
2027	\$13,000	\$9,700	\$230	\$530	\$450	\$13,000	\$9,700	
2028	\$12,000	\$8,900	\$230	\$510	\$420	\$12,000	\$8,700	
2029	\$12,000	\$8,500	\$230	\$500	\$400	\$12,000	\$8,800	
2030	\$12,000	\$8,200	\$1,200	\$1,000	\$800	\$12,000	\$8,600	
2031	\$12,000	\$7,800	\$1,200	\$1,000	\$740	\$12,000	\$8,200	
2032	\$12,000	\$7,500	\$740	\$1,100	\$760	\$12,000	\$7,700	
2033	\$11,000	\$7,000	\$730	\$1,000	\$710	\$11,000	\$7,200	
2034	\$11,000	\$6,700	\$720	\$1,000	\$660	\$11,000	\$6,900	
2035	\$11,000	\$6,400	\$710	\$970	\$620	\$11,000	\$6,500	
2036	\$11,000	\$6,100	\$700	\$950	\$580	\$11,000	\$6,300	
2037	\$11,000	\$5,800	\$690	\$920	\$540	\$11,000	\$6,000	
2038	\$11,000	\$5,400	\$860	\$890	\$500	\$11,000	\$5,700	
2039	\$10,000	\$5,100	\$850	\$870	\$470	\$9,900	\$5,400	
2040	\$10,000	\$4,900	\$830	\$840	\$440	\$10,000	\$5,300	
2041	\$10,000	\$4,600	\$820	\$820	\$410	\$9,900	\$4,900	
2042	\$10,000	\$4,400	\$810	\$790	\$380	\$9,800	\$4,600	
<b>PV 2023-2042</b>	<b>\$200,000</b>	<b>\$130,000</b>	<b>\$15,000</b>	<b>\$14,000</b>	<b>\$9,400</b>	<b>\$200,000</b>	<b>\$143,000</b>	
<b>EAV 2023-2042</b>	<b>\$13,000</b>	<b>\$12,000</b>	<b>\$970</b>	<b>\$910</b>	<b>\$770</b>	<b>\$13,000</b>	<b>\$12,000</b>	

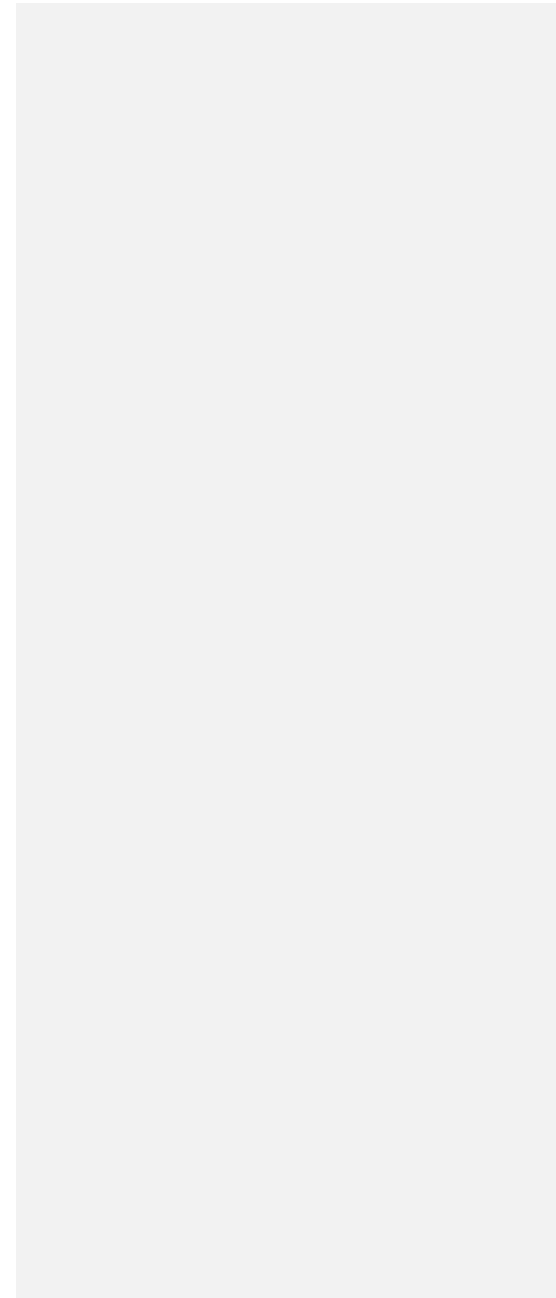
<sup>a</sup> Rows may not appear to add correctly due to rounding.

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United States Environmental Protection Agency	Office of Air Quality Planning and Standards Health and Environmental Impacts Division Research Triangle Park, NC	Publication No. EPA-452/R-23- 001 March 2023
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The EPA received a few comments/estimates for monitoring, recordkeeping, reporting, or testing costs for non-EGUs sources; these estimates were not sufficient information to present these categories of costs.

The EPA will submit an information collection request (ICR) to OMB associated with the monitoring, calibrating, recordkeeping, reporting and testing activities required for non-EGU emissions units -- *ICR for the Final Rule, Federal Good Neighbor 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 X.B.2 of the final rule preamble. The ICR includes estimated monitoring, recordkeeping, reporting, and testing costs of approximately \$3.8 million per year on average for the first three years (estimated annual compliance costs are \$570 million).

3/10/2023: It sounds like EPA already has a cost estimate for purposes of the ICR submission; why can't EPA use those estimates as an input to the total estimated compliance costs reported here? While we note that the costs are small relative to the overall compliance costs it seems incomplete to omit them from the cumulative total

The ICR for the non-EGU portion of the rule is submitted to OMB separately from the *rule preamble, RIA, and technical support documents* (rule package) that are part of the interagency review. As such, the schedules for the ICR preparation and rule package were on different timelines.

We proceeded with the RIA submittal for interagency review ~February 10. The ICR cost estimate for monitoring, recordkeeping, and reporting for non-EGUs was not completed until late February, which was later than feasible for EPA to include these non-EGU costs estimates in the RIA. In Chapter 4 at the end of Section 4.4 we later included a footnote that reflects the current cost estimate from the ICR. Given their magnitude, we addressed these costs in the same manner in the proposal RIA and in this final RIA.