Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

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Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

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Overview

This regulatory impact analysis (RIA) supports the proposed rule, the Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (FIP for the 2015 ozone NAAQS). In the proposal, in accordance with the *Wisconsin* decision, EPA proposes implementation mechanisms to achieve enforceable emissions reductions required to eliminate significant contribution of ozone precursor emissions prior to the 2023 ozone season. The initial phase of proposed emissions reductions will therefore be achieved prior to the August 2, 2024, attainment date for areas classified as Moderate nonattainment for the 2015 ozone NAAQS.[1]

EPA is proposing to promulgate new or revised FIPs for 25 states that include new NO_X ozone season emission budgets for electric generating units (EGU) sources, with implementation of these emission budgets beginning in the 2023 ozone season.[2] EPA is also proposing to adjust these states' emission budgets for each ozone season thereafter to maintain the initial stringency of the emissions budget, accounting for retirements and other changes to the EGU fleet over time. EPA is also proposing to extend the Cross-State Air Pollution Rule (CSAPR) NOx Ozone Season Group 3 Trading Program beginning in the 2023 ozone season through the 2025 ozone season. Further, EPA is proposing to establish new emissions budgets for the CSAPR NOx Ozone Season Group 3 Trading Program beginning in the 2026 ozone season, as discussed in Section VII.B.1. of the preamble. EPA is also proposing to retain two states, Iowa, and Kansas, in the CSAPR NOx Ozone Season Group 2 Trading Program.

[1] 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).

[2] In 2023, the 25 states with EGU reduction requirements include AL, AR, DE, IL, IN, KY, LA, MD, MI, MN, MS, MO, NV, NJ, NY, OH, OK, PA, TN, TX, UT, VA, WV, WI, and WY. There are no EGU reductions being required from California, and Oregon's SIP was previously approved.

For non-electric generating units (non-EGUs), EPA is proposing to promulgate new FIPs for 23 states that include new NO_X emissions limitations, with initial compliance dates for these emissions limitations beginning in 2026.[3]

Consistent with OMB Circular A-4 and EPA's *Guidelines for Preparing Economic Analyses* (2010), this RIA presents the benefits and costs of the proposed rule from 2023 through 2042. The estimated benefits are those health benefits expected to arise from reduced $PM_{2.5}$ and ozone concentrations. 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.[4] 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 estimates of other impacts of the proposed rule including its effect on retail electricity prices and fuel production.

ES.1 Identifying Needed Emissions Reductions

To reduce interstate emission transport under the authority provided in CAA section 110(a)(2)(D)(i)(I), the proposed rule further limits ozone season NO_X emissions from EGUs and non-EGUs using the same framework used by EPA in developing the CSAPR. The Interstate Transport Framework provides a 4-step process to address the requirements of the good neighbor provision for ground-level ozone and fine particulate matter ($PM_{2.5}$) 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

[3] In 2026, the 23 states with non-EGU reduction requirements include AR, CA, IL, IN, KY, LA, MD, MI, MN, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, WV, WI, and WY. AL, DE, and TN are not linked in 2026, and Oregon's SIP was previously approved.

[4] We prepared a non-EGU screening assessment (for more details on the screening assessment, see memorandum titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* in the docket), which includes estimated emissions reductions and costs. These estimates are proxies for (1) non-EGU emissions units that have emission reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs.

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, EPA applies this 4-step Interstate Transport Framework for the proposed FIP for the 2015 ozone NAAQS.

For EGUs, in identifying levels of uniform control stringency EPA assessed the same NO_X emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available for EGUs: (1) fully operating existing SCR, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing SNCRs, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting (i.e., emission reductions anticipated to occur from generation shifting from higher to lower emitting units). Levels of uniform control stringency were represented by $1,800 per ton of NO_X (2016$) in 2023 and $11,000 per ton of NO_X (2016$) in 2026.[5]

For non-EGUs, in identifying appropriate control strategies EPA developed an analytical framework[6] to evaluate the air quality impacts of potential emissions reductions from non-EGU sources located in the linked upwind states. EPA incorporated air quality modeling information, annual emissions, and information about potential controls to estimate the NO_X emissions reduction potential from non-EGU sources to determine which non-EGU industries, if subject to further control requirements, would have the greatest impact in providing air quality improvements at the downwind receptors. The evaluation in the analytical framework was subject to a marginal cost threshold of up to $7,500 per ton (2016$), which EPA determined based on information available to the Agency about existing control device efficiency and cost

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[5] EGU NO_X Mitigation Strategies Proposed Rule TSD, in the docket for this proposed rule (Docket ID No. EPA-HQ-OAR-2021-0688).

[6] Additional information on the analytical framework is presented in the memorandum titled *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 proposed rulemaking.

information. In the framework, EPA identified emissions unit types in seven industries that provide opportunities for NO_X emissions reductions that result in meaningful impacts on air quality at the downwind receptors. Because EPA determined that 2026 was the earliest potential date by which controls on non-EGU emissions units could be installed, EPA used the analytical framework with air quality modeling information for 2026 to prepare a non-EGU screening assessment for 2026 that provided estimates of emissions reductions and compliance costs. Additional information on the results of the screening assessment for 2026 is presented in the memorandum titled *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 proposed rulemaking.

ES.2 Baseline and Analysis Years

The proposed 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 year of 2023, taking into account currently on-the-books Federal regulations, substantial Federal regulatory proposals, 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 the proposed 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. It is also the first year in which state-of-the-art combustion controls can be installed on some EGUs. In addition, impacts for 2026 are important because it is in this period that additional NOx control technologies for EGUs and non-EGUs are expected to be installed where upwind linkage to downwind receptors persists. Costs and benefits from control installations may persist beyond 2026, and the RIA provides costs and benefits through 2042.

ES.3 Air Quality Modeling

The air quality modeling for the proposed FIP for the 2015 ozone NAAQS used a 2016-based modeling platform that included meteorology and base year emissions from 2016 and projected emissions for 2023 and 2026. The air quality modeling included photochemical model simulations for a 2016 base year and 2023 and 2026 future years to provide hourly concentrations of ozone nationwide. In addition, source apportionment modeling was performed for 2026 to quantify the contributions to ozone from NO_X emissions from EGUs and from point sources other than EGUs (i.e., non-EGUs) on a state-by-state basis. The modeling results for 2016, 2023, and 2026, in conjunction with emissions data for the 2023 and 2026 baseline, the proposal, and more and less stringent alternatives (regulatory control alternatives), were used to construct the air quality spatial fields that reflect the influence of emissions changes between the baseline and the regulatory control alternatives.

The air quality model simulations (i.e., model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx) version 7.10 (Ramboll Environ, 2021). Our 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.

Spatial fields provide the air quality inputs to potentially calculate health benefits for the proposed FIP for the 2015 ozone NAAQS. The spatial fields were constructed based on a method that utilizes ozone 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 concentrations. This method, as described in Appendix 3A, was originally developed to support the RIA for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units and, most recently, the RIA for the Revised CSAPR Update final rule.

We generated spatial fields of seasonal ozone concentrations associated with the regulatory control alternatives. The data for creating spatial fields for each scenario include: (1) EGU and non-EGU ozone season NO_x emissions for the 2023 and 2026 baseline scenarios and the regulatory control alternatives, (2) spatial fields of April through September MDA8[7] (AS-MO3) average ozone for the 2023 and 2026 baseline scenarios, and (3) the spatial field of mean AS-MO3 ozone contributions for the hours that correspond to the time periods of MDA8 concentrations. To calculate ozone-related benefits in 2023 and 2026 we used the ozone season EGU and non-EGU NOx emissions for the 2023 and 2026 baseline scenarios along with emissions for the regulatory control alternatives.

ES.4 Control Strategies and Emissions Reductions

The RIA analyzes emission budgets for EGUs and ozone season emissions limits for non-EGUs, as well as a more and a less stringent alternative to the proposed rule. The more and less stringent alternatives differ from the proposed FIP for the 2015 ozone NAAQS in that they set different EGU NO_X ozone season emission budgets and different dates for compliance with unit-specific emission rate limits for the affected EGUs and cover different industries or emissions units for non-EGUs. Table ES-1 below presents the less stringent alternatives, proposed 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 ES-1. Regulatory Control Alternatives for EGUs and Non-EGUs

Regulatory Control Alternative	NO_X Controls Implemented for EGUs within IPM
Less Stringent Alternative	1) 2023 onwards: Shift generation to minimize costs 2) 2023 onwards: Fully operate existing SCRs during ozone season 3) 2023 onwards: Fully operate existing SNCRs during ozone season 4) In 2023 install state-of-the-art combustion controls 5) In 2028 model run year, impose backstop emission rate limits on coal units greater than 100 MW within the 23-state region that lack SCR controls, forcing units to retrofit or retire. 6) In 2028 model run year, impose backstop emission rate limits on oil/gas steam units greater than 100 MW that operated at a greater than 20% capacity factor historically within the 23-state region that lack SCR controls, forcing units to retrofit or retire.[8]

[7] MDA8 is defined as maximum daily 8-hour average ozone concentration, and MDA1 is defined as the maximum daily 1-hour ozone concentration.
[8] The 20% capacity factor cutoff applied is representative of the fleet of O/G steam units assumed to have SCR retrofit potential in its state budgets. In the proposal, EPA defined this segment using 150 tons per season cutoff, which provides a similar size of the O/G steam fleet as the 20% capacity factor value used in this analysis.

Regulatory Control Alternative	NO_X Controls Implemented for EGUs within IPM
Proposed Rule	(All Controls above and) 7) In 2026, impose backstop emission rate limits on coal units greater than 100 MW within the 23-state region that lack SCR controls, forcing units to retrofit or retire. 8) In 2026, impose backstop emission rate limits on oil/gas steam units greater than 100 MW that operated at a greater than 20% capacity factor historically within the 23-state region that lack SCR controls, forcing units to retrofit or retire.
More Stringent Alternative	(Controls 1 – 4, 7 and 8 above and) 9) In 2026, impose backstop emission rate limits on all oil/gas steam units greater than 100 MW within the 23-state region that lack SCR controls, forcing units to retrofit or retire.
	NO_X Emissions Limits for Non-EGUs – Emissions Unit Types and Industries
Less Stringent Alternative	1) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas, 2) Kilns in Cement and Cement Product Manufacturing, 3) Boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing, 4) Furnaces in Glass and Glass Product Manufacturing, and
Proposed Rule	(All emissions unit types and industries above and) 5) *Impactful* boilers* in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.
More Stringent Alternative	(All emissions unit types and industries above and) 6) *All* boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

*Impactful boilers are boilers with design capacity of 100 mmBtu/hr or greater.

ES.4.1 EGUs

The proposal establishes NO_X emissions budgets requiring fossil fuel-fired power plants (EGUs) in 25 states to participate in an allowance-based ozone season (May 1 through September 30) trading program beginning in 2023. The EGUs covered by the proposed 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 VI.C. of the preamble.

The proposed FIP requirements establish ozone season NO_X emissions budgets for EGUs in 25 states starting in 2023 and require EGUs in these states to participate in a revised version of the CSAPR NO_X Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.[9] In addition, beginning in the 2027 ozone season, coal facilities greater than 100 MW lacking SCR controls and certain oil/gas steam facilities greater than 100 MW that

[9] As explained in Section VI.C.1 of the preamble, EPA proposes finding that EGU sources within the State of California are sufficiently controlled such that no further emission reductions are needed from them to eliminate significant contribution to downwind states.

lack existing SCR controls located in these 23 states must meet daily emission rate limits, effectively forcing affected units to install new SCR controls, find other means of compliance, or retire. The 36-month timeframe allows for design, permitting, and installation. EPA used a third-party global engineering consulting firm in the summer of 2021 to further validate its timing assumptions. While all those stages can occur within 36 months, the point from capital investment to completion can be well under 36 months. This timeframe has been demonstrated in prior installations and is consistent with prior EPA rules. The timing is also consistent with EPA's legal authorities and obligations as discussed in Section VII in the preamble. States that do not have additional mitigation measures assumed in 2026 continue to remain part of the revised group 3 Trading Program.

In the proposal, we introduce additional features to the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets over time and backstop daily emission rate limits for most coal-fired units, that were not included in previous CSAPR NO_X 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. The 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. For affected uncontrolled units in the 23 states, starting in 2026, the analysis imposes an emission rate constraint that forces affected units to either install new SCR retrofits, find other means of compliance, or retire.[10] The analysis does not explicitly capture the dynamic budget adjustments over time, 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. Any new fossil fuel-fired EGU serving a generator with a nameplate capacity exceeding 25 MW capacity that meets the applicability criteria and is deployed in any of the states covered by this proposal's EGU ozone-season NO_X program would be subject to the same requirements as other

[10] The proposed rule assumes SCR retrofit potential starting in 2026 and it is reflected in the 2026 state emissions budgets. The daily backstop emission rate does not apply until 2027, but the majority of units retrofitting are anticipated to do so by 2026 to assist with the 2026 state emissions budget compliance. EPA's IPM model run years are 2026 and 2028. The SCR compliance behavior is generally expected to occur no later than 2027, and in 2026 in many cases. Therefore, EPA models this daily backstop emission rate in 2026 (when choosing between model run year 2026 and 2028) to conservatively reflect compliance cost in the first year in which the technology is in place for some units.

covered EGUs. Reported heat input data from any new covered EGUs would be factored into dynamic budgets through the computational process outlined in the proposal.

For the NO_X controls for EGUs identified in Table ES-1, under the proposed rule and the less stringent and the more stringent alternatives, 248 EGUs not already doing so in 2019 are projected to fully operate existing SCRs.[11] Under the proposed rule and the less stringent and more stringent alternatives, 27 units are projected to fully operate existing SNCRs. Under the proposed rule and the less stringent and the more stringent alternatives, 23 units are projected to install state-of-the-art combustion controls. The book-life of the new combustion controls is assumed to be 15 years.

Under the proposed rule an incremental 18 GW of coal and 4 GW of oil/gas retirements are projected by 2030. Under the more stringent alternative 20 GW of coal and 7 GW of oil/gas retirements are projected by 2030. Under the less stringent alternative 13 GW of coal and 4 GW of oil/gas retirements are projected by 2030. For additional details, see the EGU NO_X Mitigation Strategies Proposed Rule TSD.

Table ES-2 shows the ozone season NO_X emissions reductions expected from the proposed rule as well as the more and less stringent alternatives analyzed from 2023 through 2030, and for 2035 and 2042. In addition, Table ES-2 shows the annual NO_X, SO_2, $PM_{2.5}$, and CO_2 emissions reductions expected from the proposed rule as well as the more and less stringent alternatives analyzed from 2023 through 2030, and for 2035 and 2042.

Table ES-2. EGU Ozone Season NO_X Emissions Changes and Annual Emissions Changes for NO_X, SO_2, $PM_{2.5}$, and CO_2 for the Regulatory Control Alternatives from 2023 - 2042[12]

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
2023			
NOx (ozone season)	6,000	6,000	7,000
NOx (annual)	10,000	10,000	10,000
SO_2 (annual)*	--	1,000	2,000
CO_2 (annual, thousand metric)	--	--	--
$PM_{2.5}$ (annual)	--	--	--
2024			
NOx (ozone season)	26,000	14,000	29,000
NOx (annual)	42,000	22,000	45,000
SO_2 (annual)	42,000	20,000	43,000

[11] The engineering analysis used to develop the illustrative budgets in the RIA relied on 2019 historical data.
[12] This analysis is limited to the geographically contiguous lower 48 states.

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
CO_2 (annual, thousand metric)	18,000	10,000	19,000
$PM_{2.5}$ (annual)	4,000	1,000	4,000
2025			
NOx (ozone season)	46,000	22,000	51,000
NOx (annual)	73,000	33,000	80,000
SO_2 (annual)	83,000	39,000	84,000
CO_2 (annual, thousand metric)	37,000	19,000	38,000
$PM_{2.5}$ (annual)	9,000	2,000	9,000
2026			
NOx (ozone season)	47,000	32,000	53,000
NOx (annual)	81,000	55,000	87,000
SO_2 (annual)	106,000	76,000	108,000
CO_2 (annual, thousand metric)	40,000	26,000	42,000
$PM_{2.5}$ (annual)	9,000	5,000	9,000
2027			
NOx (ozone season)	49,000	42,000	54,000
NOx (annual)	88,000	76,000	95,000
SO_2 (annual)	129,000	113,000	131,000
CO_2 (annual, thousand metric)	43,000	34,000	46,000
$PM_{2.5}$ (annual)	10,000	7,000	10,000
2030			
NOx (ozone season)	52,000	52,000	57,000
NOx (annual)	96,000	98,000	100,000
SO_2 (annual)	104,000	100,000	103,000
CO_2 (annual, thousand metric)	50,000	45,000	50,000
$PM_{2.5}$ (annual)	9,000	9,000	9,000
2035			
NOx (ozone season)	49,000	50,000	52,000
NOx (annual)	90,000	93,000	93,000
SO_2 (annual)	96,000	93,000	98,000
CO_2 (annual, thousand metric)	38,000	36,000	38,000
$PM_{2.5}$ (annual)	11,000	12,000	10,000
2042			
NOx (ozone season)	47,000	47,000	48,000
NOx (annual)	70,000	75,000	71,000
SO_2 (annual)	54,000	50,000	54,000
CO_2 (annual, thousand metric)	25,000	23,000	24,000
$PM_{2.5}$ (annual)	8,000	9,000	8,000

Emissions changes for NO_x, SO_2, and $PM_{2.5}$ are tons.
* SO2 emissions reductions under the proposed rule are 350 tons and rounded to zero. SO2 emissions reductions under the less stringent alternative are 507 tons and rounded to 1000 tons. SO2 emissions reductions are 1,699 tons under the more stringent alternative and rounded to 2,000 tons. Given the rounding, the difference between the reductions under the proposed rule and the less stringent alternative is approximately 160 tons.

ES.4.2 Non-EGUs

The proposal includes ozone season NO_X emissions limitations for non-EGUs with an initial compliance date of 2026 for the 23 states.[13] A summary of the non-EGU emissions unit types, emissions limits, and industries is presented below in Table ES-3. A more detailed summary of the proposed emissions limits can be found in Section I.B. of the preamble.

Table ES-3. Non-EGU Emissions Unit Types, Emissions Limits, and Industries

Emissions Unit Type	Emissions Limit	Industry	NAICS
Reciprocating internal combustion engines	g/hp-hr	Pipeline Transportation of Natural Gas	4862
Kilns	lb/ton of clinker	Cement and Concrete Product Manufacturing	3273
Boilers and furnaces	Depending on equipment type - lb/mmBtu, lb/ton of steel, lb/ton, lb/ton coal pushed, lb/ton coal charged, work practice standards	Iron and Steel Mills and Ferroalloy Manufacturing	3311
Furnaces	lb/ton glass produced	Glass and Glass Product Manufacturing	3272
Impactful boilers*	lbs NOx/mmBtu	Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills	3251, 3241, 3221

North American Industry Classification System (NAICS)
*Impactful boilers are boilers with design capacity of 100 mmBtu/hr or greater.

Table ES-4 below provides a summary of the 2019 ozone season emissions for non-EGUs for the 23 states subject to the proposed FIP in 2026, along with the estimated ozone season reductions for the proposal and the less and more stringent alternatives for 2026.[14] The estimated emissions reductions by state for the proposed alternative are from the non-EGU screening assessment, and the estimated reductions by state for the less and more stringent alternatives were estimated for the RIA using the same methodology. Table ES-5 below shows the industries, number and type of emissions units expected to install controls, and the total estimated ozone season emissions reductions, based on the results of the 2026 screening assessment. Additional results from the screening assessment for 2026 are presented in the memorandum titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026.*

[13] If an emissions unit installs SCR or SNCR to meet an emissions limit in response to the proposed FIP that would be a physical change under new source review (NSR) and lead to an assessment of potential emissions changes. If the installation of SCR results in an emissions increase that exceeds the thresholds in the NSR regulations for one or more regulated NSR pollutants, including the netting analysis, the changes would trigger the applicability of NSR.
[14] 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.

Table ES-4. Ozone Season (OS) NO_X Emissions and Emissions Reductions (tons) for the Proposed Rule and the Less and More Stringent Alternatives*

State	2019 OS NOx Emissions	Proposed Rule - OS NOx Reductions	Less Stringent Alternative - OS NOx Reductions	More Stringent Alternative - OS NOx Reductions
AR	8,265	1,654	922	1,654
CA	14,579	1,666	1,598	1,777
IL	16,870	2,452	2,452	2,553
IN	19,604	3,175	2,787	3,175
KY	11,934	2,291	2,291	2,291
LA	35,831	6,769	4,121	6,955
MD	2,365	45	45	45
MI	18,996	2,731	2,731	3,093
MN	17,591	673	673	789
MO	9,109	3,103	3,103	3,103
MS	12,284	1,761	1,577	1,761
NJ	2,025	0	0	29
NV	2,418	0	0	0
NY	6,003	500	389	613
OH	19,729	2,790	2,611	2,814
OK	22,146	3,575	3,575	3,871
PA	15,861	3,284	3,132	3,340
TX	47,135	4,440	4,440	6,596
UT	6,276	757	757	757
VA	7,041	1,563	1,465	1,660
WI	6,571	2,150	677	2,234
WV	9,825	982	982	982
WY	10,335	826	826	826
Totals	322,793	47,186	41,153	50,918

* In the non-EGU screening assessment for 2026, EPA estimated emissions reduction potential from the non-EGU industries and emissions units. In the screening assessment, EPA used CoST to identify emissions units, emissions reductions, and associated compliance costs to evaluate the effects of potential non-EGU emissions control measures and technologies. CoST is designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. The estimates from CoST identify proxies for (1) non-EGU emissions units that have 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. The control cost estimates do not include monitoring, recordkeeping, reporting, or testing costs. This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. For more information on CoST, go to the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

Table ES-5. By Industry, Number and Type of Emissions Units and Total Estimated Emissions Reductions (ozone season tons)

Industry	Region	Number of Units by Type			Ozone Season Emission Reductions (tons) by Type of Unit		
		Boilers	Internal	Industrial	Boilers	Internal	Industrial
Glass and Glass Product Manufacturing	East	-	-	41	-	-	6,367
	West	-	-	3	-	-	299
Cement and Concrete Product Manufacturing	East	1	-	39	16	-	5,948
	West	-	-	8	-	-	2,128
Iron and Steel Mills and Ferroalloy	East	25	-	15	2,044	-	1,207
Pipeline Transportation of Natural Gas	East	-	296	-	-	22,390	-
	West	-	11	-	-	754	-
Basic Chemical Manufacturing	East	17	-	-	1,698	-	-
Petroleum and Coal Products Manufacturing	East	9	-	-	962	-	-
	West	1	-	-	68	-	-
Pulp, Paper, and Paperboard Mills	East	25	-	-	3,305	-	-

Blue highlights reflect western state information

ES.5 Cost Impacts

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 proposed rule 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 ES-6. Total National Compliance Cost Estimates (millions of 2016$) for the Proposed Rule and the Less and More Stringent Alternatives

	Proposed Rule		**Less Stringent Alternative**		**More Stringent Alternative**	
	3 Percent	**7 Percent**	**3 Percent**	**7 Percent**	**3 Percent**	**7 Percent**
Present Value EGU 2023-2042	$17,000	$11,000	$16,000	$9,400	$23,000	$15,000
Present Value Non-EGU 2026-2042	$4,800	$3,100	$4,200	$2,700	$5,200	$3,300
Present Value Total 2023-2042	**$22,000**	**$14,000**	**$20,000**	**$12,000**	**$28,000**	**$18,000**
EGU Equivalent Annualized Value	$1,100	$1,000	$1,100	$890	$1,500	$1,400
Non-EGU Equivalent Annualized Value	$320	$290	$280	$250	$350	$310
Total Equivalent Annualized Value	**$1,500**	**$1,300**	**$1,300**	**$1,100**	**$1,900**	**$1,700**

Note: Values have been rounded to two significant figures

ES.6 Benefits

ES.6.1 Benefits Estimates

The proposed rule is expected to reduce ozone season and annual NO_X emissions. In the presence of sunlight, NO_X, and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X 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 NOx, the proposed rule is also expected to reduce emissions of direct $PM_{2.5}$ and SO_2 throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects.

In this RIA for the proposed FIP for the 2015 ozone NAAQS, EPA uses both full-form and reduced-form techniques to quantify benefits. Both approaches rely on the same methods for quantifying the number and value of air pollution-attributable premature deaths and illnesses, which is described in the Technical Support Document for the Final Revised CSAPR Update for the 2008 Ozone NAAQS titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*. Methods used to estimate $PM_{2.5}$ benefits are described in the TSD titled *Estimating the Benefit per Ton of Reducing Directly-Emitted $PM_{2.5}$, $PM_{2.5}$ Precursors and Ozone Precursors from 21 Sectors*. Both methods incorporate evidence reported in the most recent completed PM and Ozone Integrated Science Assessments (ISAs) and accounts 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 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 in Chapter 5.

Table ES-7 and Table ES-8 report the estimated number of reduced premature deaths and illnesses in 2023 and 2026 relative to the baseline along with the 95% confidence interval. The number of reduced estimated deaths and illnesses from the proposed rule and more and less stringent alternatives is calculated from the sum of individual reduced mortality and illness risk across the population. Table ES-9 and Table ES-10 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. In each of these tables, for each discount rate and regulatory control alternative, multiple benefits estimates are presented reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates.

Table ES-7. Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Proposal and More and Less Stringent Alternatives for 2023 (95% Confidence Interval) [a,b]

		Proposal	More Stringent Alternative	Less Stringent Alternative[h]
Avoided premature respiratory mortalities				
Long-term exposure	Turner *et al*. (2016)[c]	44 (31 to 57)	51 (36 to 66)	44 (31 to 57)
Short-term exposure	Katsouyanni *et al.* (2009)[c,d] and Zanobetti *et al*. (2008)[d]pooled	2 (0.8 to 3.1)	2.3 (0.94 to 3.7)	2 (0.81 to 3.2)
Morbidity effects				
Long-term exposure	Asthma onset[e]	350 (300 to 390)	400 (340 to 450)	350 (300 to 400)
	Allergic rhinitis symptoms[g]	2,000 (1,000 to 2,900)	2,200 (1,200 to 3,300)	2,000 (1,000 to 2,900)
Short-term exposure	Hospital admissions—respiratory[d]	5.3 (-1.4 to 12)	6.1 (-1.6 to 14)	5.3 (-1.4 to 12)
	ED visits—respiratory[f]	110 (30 to 230)	120 (34 to 260)	110 (30 to 230)
	Asthma symptoms	62,000 (-7,700 to 130,000)	71,000 (-8,800 to 150,000)	62,000 (-7,700 to 130,000)
	Minor restricted-activity days[d,f]	30,000 (12,000 to 47,000)	34,000 (14,000 to 54,000)	30,000 (12,000 to 48,000)
	School absence days	22,000 (-3,100 to 47,000)	26,000 (-3,600 to 54,000)	22,000 (-3,200 to 47,000)

[a] Values rounded to two significant figures.

[b] We estimated ozone benefits for changes in NOx for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors 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 proposed standards would become effective.

[c] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.

[d] Converted ozone risk estimate metric from MDA1 to MDA8.

[e] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.

[f] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.

[g] Converted ozone risk estimate metric from DA24 to MDA8.

[h] The proposed rule imposes unit level emission rate limits on EGUs in the 2026, which are imposed in the 2025 IPM run year, while the less stringent alternative assumes these are imposed in 2028, and in IPM are applied in the 2028 run year. The unit level emission rate limits drive much of the EGU retirement activity, and retirements are delayed in the less stringent alternative relative to the proposed rule. 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 less stringent alternative relative to the proposed rule due to delayed retirements. As such, emissions are slightly lower in 2023 in some states in the less stringent alternative relative to the proposed rule.

Table ES-8. Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Proposal and More and Less Stringent Alternatives for 2026 (95% Confidence Interval) [a,b,h]

Exposure Duration	Study	Affected Facility	Proposal	More Stringent Alternative	Less Stringent Alternative
			Avoided premature respiratory mortalities		
Long-term exposure	Turner *et al*. (2016)[c]	EGUs	450 (310 to 580)	520 (360 to 670)	210 (140 to 270)
		Non-EGUs	510 (350 to 660)	550 (380 to 710)	450 (310 to 580)
		EGUs + Non-EGUs	960 (660 to 1,200)	1,100 (740 to 1,400)	650 (450 to 850)
Short-term exposure	Katsouyanni *et al.* (2009)[c,d] and Zanobetti *et al.* (2008)[d]pooled	EGUs	20 (8.2 to 32)	24 (9.5 to 37)	9.4 (3.8 to 15)
		Non-EGUs	23 (9.3 to 36)	25 (10 to 39)	20 (8.2 to 32)
		EGUs + Non-EGUs	43 (18 to 68)	48 (19 to 76)	30 (12 to 47)
	Morbidity effects				
Long-term exposure	Asthma onset[e]	EGUs	3,300 (2,800 to 3,700)	3,800 (3,300 to 4,300)	1,600 (1,300 to 1,800)
		Non-EGUs	3,800 (3,300 to 4,400)	4,200 (3,600 to 4,700)	3,400 (2,900 to 3,800)
		EGUs + Non-EGUs	7,100 (6,100 to 8,100)	7,900 (6,800 to 9,000)	4,900 (4,200 to 5,600)
	Allergic rhinitis symptoms[g]	EGUs	19,000 (9,900 to 27,000)	22,000 (11,000 to 32,000)	8,900 (4,700 to 13,000)
		Non-EGUs	22,000 (12,000 to 32,000)	24,000 (13,000 to 35,000)	19,000 (10,000 to 28,000)
		EGUs + Non-EGUs	41,000 (22,000 to 59,000)	46,000 (24,000 to 66,000)	28,000 (15,000 to 41,000)
Short-term exposure	Hospital admissions—respiratory[d]	EGUs	55 (-14 to 120)	63 (-17 to 140)	25 (-6.5 to 55)
		Non-EGUs	61 (-16 to 140)	66 (-17 to 150)	54 (-14 to 120)
		EGUs + Non-EGUs	120 (-30 to 260)	130 (-34 to 290)	79 (-21 to 170)
	ED visits—respiratory[f]	EGUs	1,100 (290 to 2,200)	1,200 (340 to 2600)	500 (140 to 1,100)
		Non-EGUs	1,200 (340 to 2,600)	1,300 (360 to 2,800)	1,100 (300 to 2,300)
		EGUs + Non-EGUs	2,300 (630 to 4,800)	2,600 (700 to 5,400)	1,600 (430 to 3,300)
	Asthma symptoms	EGUs	610,000 (-75,000 to 1,300,000)	700,000 (-86,000 to 1,500,000)	290,000 (-35,000 to 590,000)

	Non-EGUs	710,000 (-87,000 to 1,500,000)	770,000 (-94,000 to 1,600,000)	620,000 (-77,000 to 1,300,000)
	EGUs + Non-EGUs	1,300,000 (-160,000 to 2,700,000)	1,500,000 (-180,000 to 3,000,000)	910,000 (-110,000 to 1,900,000)
Minor restricted-activity days[d,f]	EGUs	280,000 (110,000 to 440,000)	330,000 (13,000 to 520,000)	130,000 (53,000 to 210,000)
	Non-EGUs	330,000 (130,000 to 520,000)	360,000 (140,000 to 560,000)	290,000 (120,000 to 460,000)
	EGUs + Non-EGUs	610,000 (240,000 to 970,000)	680,000 (270,000 to 1,100,000)	420,000 (170,000 to 670,000)
School absence days	EGUs	220,000 (-30,000 to 450,000)	250,000 (-35,000 to 520,000)	100,000 (-14,000 to 210,000)
	Non-EGUs	250,000 (-35,000 to 530,000)	270,000 (-38,000 to 570,000)	220,000 (-31,000 to 460,000)
	EGUs + Non-EGUs	470,000 (-66,000 to 980,000)	520,000 (-74,000 to 1,100,000)	320,000 (-46,000 to 670,000)

[a] Values rounded to two significant figures.
[b] We estimated ozone benefits for changes in NOx for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors for EGUs in 2026.
[c] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.
[d] Converted ozone risk estimate metric from MDA1 to MDA8.
[e] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.
[f] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.
[g] Converted ozone risk estimate metric from DA24 to MDA8.
[h] Non-EGU benefits estimates are ozone-related only. An illustrative analysis of non-EGU PM benefits estimates is presented in Chapter 5, Table 5-8.

Table ES-9. Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Proposed Policy Scenarios in 2023 (95% Confidence Interval; millions of 2016$)[a,b]

Disc. Rate	Pollutant	Proposal			More Stringent Alternative			Less Stringent Alternative		
3%	Ozone Benefits	$57 ($15 to $120)[c]	*and*	$460 ($51 to $1,200)[d]	$65 ($17 to $140)[c]	*and*	$530 ($59 to $1,400)[d]	$57 ($15 to $120)[c]	*and*	$460 ($51 to $1,200)[d]
	PM BPTs	$44	*and*	$45	$190	*and*	$190	$59	*and*	$60
	Ozone Benefits plus PM BPTs	$100 ($59 to $160)[c]	*and*	$500 ($96 to $1,200)[d]	$250 ($200 to $330)[c]	*and*	$720 ($250 to $1,600)[d]	$120 ($74 to $180)[c]	*and*	$520 ($110 to $1,300)[d]
7%	Ozone Benefits	$51 ($9.6 to 110)[c]	*and*	$410 ($42 to $1,100)[d]	$58 ($11 to $130)[c]	*and*	$480 ($49 to $1,300)[d]	$51 ($9.6 to $110)[c]	*and*	$410 ($42 to $1,100)[d]
	PM BPTs	$40	*and*	$41	$170	*and*	$170	$53	*and*	$54
	Ozone Benefits plus PM BPTs	$90 ($49 to $150)[c]	*and*	$450 ($83 to $1,100)[d]	$230 ($180 to $300)[c]	*and*	$650 ($220 to $1,400)[d]	$100 ($63 to $170)[c]	*and*	$470 ($97 to $1,100)[d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated ozone benefits for changes in NOx for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors 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 proposed standards would become effective.
[c] Using the pooled short-term ozone exposure mortality risk estimate.
[d] Using the long-term ozone exposure mortality risk estimate.

Table ES-10. Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Proposed Policy Scenario in 2026 (95% Confidence Interval; millions of 2016$)[a,b]

Disc Rate	Pollutant	Proposal			More Stringent Alternative			Less Stringent Alternative		
3%	Ozone Benefits	$1,200 ($310 to $2,600) [c]	*and*	$10,000 ($1,100 to $26,000) [d]	$1,300 (340 to $2,900) [c]	*and*	$11,000 ($1,200 to $29,000) [d]	$830 ($210 to $1,800) [c]	*and*	$6,900 ($760 to $18,000) [d]
	PM BPTs	$8,100	*and*	$8,300	$7,800	*and*	$7,900	$3,400	*and*	$3,500
	Ozone Benefits plus PM BPTs	$9,300 ($8,400 to $11,000)[c]	*and*	$18,000 ($9,400 to $35,000)[d]	$9,100 ($8,100 to $11,000)[c]	*and*	$19,000 ($9,200 to $37,000)[d]	$4,300 ($3,700 to $5,200)[c]	*and*	$10,000 ($4,300 to $22,000)[d]
7%	Ozone Benefits	$1,100 ($200 to $2,400) [c]	*and*	$9,000 ($920 to $24,000) [d]	$1,200 ($220 to $2,700) [c]	*and*	$10,000 ($1,000 to $26,000) [d]	$740 ($140 to $1,700) [c]	*and*	$6,200 ($630 to $16,000) [d]
	PM BPTs	$7,300	*and*	$7,400	$7,000	*and*	$7,100	$3,100	*and*	$3,200
	Ozone Benefits plus PM BPTs	$8,400 ($7,500 to $9,700)[c]	*and*	$16,000 ($8,300 to $31,000)[d]	$8,200 ($7,200 to $9,700)[c]	*and*	$17,000 ($8,200 to $34,000)[d]	$3,800 ($3,200 to $4,800)[c]	*and*	$9,300 ($3,800 to $19,000)[d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in NOx for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2026. This table represents changes in EGU and non-EGU ozone season and annual controls.
[c] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.
[d] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.

ES.6.2 Climate Benefits

Elevated concentrations of greenhouse gases (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_2 emissions reductions expected from this proposed rule. Climate benefits from reducing emissions of CO_2 can be monetized using estimates of the social cost of carbon (SC-CO_2). However, due to a court order, EPA cannot present these monetized estimates in the analysis of this proposed rule at this time. On February 11, 2022, the U.S. District Court for the Western District of Louisiana issued an injunction concerning the monetization of benefits of greenhouse gas emission reductions by EPA and other defendants. *See Louisiana v. Biden*, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Accordingly, monetized climate benefits are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. See Chapter 5, Section 5.2 for more discussion.

ES.6.3 Additional Unquantified Benefits

Data, time, and resource limitations prevented EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with direct exposure to NO_2 and SO_2 (independent of the role NO_2 and SO_2 play as precursors to $PM_{2.5}$ and ozone), 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, $PM_{2.5}$, NO_2 or SO_2. For a qualitative description of these and water quality benefits, please see Chapter 5, Section 5.3, Table 5-9.

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 EPA's EJ Technical Guidance[15] 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?

[15] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

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, EPA developed an analytical approach that considers the purpose and specifics of the proposed rulemaking, as well as the nature of known and potential exposures and impacts. For the proposal, we quantitatively evaluate 1) the proximity of affected facilities to potentially disadvantaged populations (Chapter 7, Section 7.3.1), 2) the distribution of total ozone concentrations in the baseline across different demographic groups (Chapter 7, Sections 7.4.1.1 and 7.4.2.1), and 3) how regulatory alternatives differentially impact the ozone concentration changes experienced by different demographic populations (Chapter 7, Sections 7.4.1.2 and 7.4.2.2). Each of these analyses depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Because the pollution impacts that are the focus of this proposal are substantially downwind from affected facilities, the proximity analysis cannot be used to demonstrate disproportionate pollution impacts in the baseline. However, the analysis indicates that certain demographic subgroups living near affected facilities could potentially experience differential effects in terms of local environmental stressors such as noise and traffic.

The baseline analysis of the average April-September warm season maximum daily 8-hour average ozone concentrations (AS-MO3) addresses EJ concerns more directly than the proximity analyses, as it evaluates the environmental stressor (ozone) primarily affected by the regulatory action. Results of this baseline analysis suggest that there likely are potential EJ concerns associated with small average differences in ozone exposure across demographic groups in the baseline. However, when we consider how the regulatory alternatives will affect ozone concentrations, and the distribution of those concentrations across different demographic groups, we see that overall, reductions in AS-MO3 concentrations under the proposal, as well as the more stringent and less stringent alternatives, are predicted to result in very similar ozone reductions across different demographic groups in future years across both EGUs and non-

EGUs. Importantly, this proposal is expected to lower ozone in many areas, including residual ozone nonattainment areas, and thus mitigate some pre-existing health risks of ozone across all populations evaluated.

ES.8 Results of Benefit-Cost Analysis

Below in Table ES-11 through

Table ES-13, 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 net benefits of the proposed rule and more and less stringent alternatives reflect the benefits of implementing EGU and non-EGU emissions reductions strategies for the affected states via the FIPs minus the costs of those emissions reductions. The estimated social costs to implement the proposed rule, as described in this document, are approximately -$210 million in 2023 and $1,100 million in 2026 (2016$). Compliance costs are negative because in 2023 the EGU compliance costs are negative. 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.

The estimated monetized benefits associated with reductions in $PM_{2.5}$ and ozone concentrations from implementation of the proposed rule are approximately $100 and $500 million in 2023 (2016$, based on a real discount rate of 3 percent). For 2026, the estimated monetized benefits from implementation of the proposed rule are approximately $9,300 and $18,000 million (2016$, based on a real discount rate of 3 percent). The monetized benefits estimates do not include important climate benefits that were not monetized in this RIA. In addition, there are important water quality benefits and health benefits associated with reductions in concentrations of air pollutants other than $PM_{2.5}$ and ozone that are not quantified.

EPA calculates the monetized net benefits of the proposal by subtracting the estimated monetized compliance costs from the estimated monetized benefits in 2023, 2026, and 2030.

The annual monetized net benefits of the proposed rule in 2023 (in 2016$) are approximately $310 and $710 million using a 3 percent discount rate. The annual monetized net benefits of the proposal in 2026 are approximately $8,200 and $17,000 million using a 3 percent real discount rate. The annual monetized net benefits of the proposal in 2030 are approximately $7,700 and $18,000 million using a 3 percent real discount rate. Table ES-11 presents a summary of the monetized benefits, costs, and net benefits of the proposed rule and the more and less stringent alternatives for 2023. Table ES-12 presents a summary of these impacts for the proposed rule and the more and less stringent alternatives for 2026, and

Table ES-13 presents a summary of these impacts for the proposed rule and the more and less stringent alternatives for 2030. These results present an incomplete overview of the effects of the proposal, because important categories of benefits -- including benefits from reducing climate pollution, 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 proposal to be more net beneficial than this table reflects.

Table ES-11. Monetized Benefits, Costs, and Net Benefits of the Proposed Rule and Less and More Stringent Alternatives for 2023 for the U.S. (millions of 2016$)[a,b]

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
Benefits[c]	$100 and $500	$120 and $520	$250 and $720
Costs[d]	-$210	-$170	-$180
Net Benefits	**$310 and $710**	**$290 and $690**	**$430 and $900**

[a] We focus results to provide a snapshot of costs and benefits in 2023, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.
[d] The costs presented in this table are 2023 annual estimates for each alternative analyzed. 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.

Table ES-12. Monetized Benefits, Costs, and Net Benefits of the Proposed Rule and Less and More Stringent Alternatives for 2026 for the U.S. (millions of 2016$)[a,b]

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
Benefits[c]	$9,300 and $18,000	$4,300 and $10,000	$9,100 and $19,000
Costs[d]	$1,100	-$49	$1,600
Net Benefits	**$8,200 and $17,000**	**$4,300 and $10,000**	**$7,500 and $17,000**

[a] We focus results to provide a snapshot of costs and benefits in 2026, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.
[d] The costs presented in this table are 2026 annual estimates for each alternative analyzed. 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.

Table ES-13. Monetized Benefits, Costs, and Net Benefits of the Proposed Rule and Less and More Stringent Alternatives for 2030 for the U.S. (millions of 2016$)[a,b]

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
Benefits[c]	$9,400 and $20,000	$4,300 and $11,000	$9,200 and $21,000
Costs[d]	$1,600	$1,600	$2,200
Net Benefits	**$7,700 and $18,000**	**$2,800 and $9,700**	**$7,000 and $19,000**

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.
[d] The costs presented in this table are 2030 annual estimates for each alternative analyzed. 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.

As part of fulfilling analytical guidance with respect to E.O. 12866, 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 proposed rule, annual benefits and costs are discounted to 2022 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.

For the twenty-year period of 2023 to 2042, the PV of the net benefits, in 2016$ and discounted to 2022, is $220,000 million when using a 3 percent discount rate and $130,000 when using a 7 percent discount rate. The EAV is $15,000 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 proposed rule can be found in Table ES-14. Estimates in the table are presented as rounded values.

Table ES-14. Summary of Present Values and Equivalent Annualized Values for the 2023-2042 Timeframe for Estimated Monetized Compliance Costs, Benefits, and Net Benefits for the Proposed Rule (millions of 2016$, discounted to 2022)[a,b]

	Benefits		Cost[c]		Net Benefits	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2023	$500	$450	($210)		$710	$660
2024	$520	$460	$710		-$190	-$240
2025	$530	$470	$710		-$180	-$230
2026	$18,000	$16,000	$1,100		$17,000	$15,000
2027	$19,000	$17,000	$2,000		$17,000	$15,000
2028	$18,000	$16,000	$2,000		$16,000	$14,000
2029	$19,000	$17,000	$2,000		$17,000	$15,000
2030	$20,000	$18,000	$1,600		$18,000	$16,000
2031	$20,000	$18,000	$1,600		$19,000	$16,000
2032	$21,000	$18,000	$2,100		$18,000	$16,000
2033	$20,000	$18,000	$2,100		$18,000	$16,000
2034	$21,000	$18,000	$2,100		$19,000	$16,000
2035	$21,000	$19,000	$2,100		$19,000	$16,000
2036	$21,000	$19,000	$2,100		$19,000	$17,000
2037	$22,000	$19,000	$2,100		$19,000	$17,000
2038	$21,000	$19,000	$1,300		$20,000	$18,000
2039	$22,000	$19,000	$1,300		$20,000	$18,000
2040	$22,000	$19,000	$1,300		$21,000	$18,000
2041	$22,000	$19,000	$1,300		$21,000	$18,000
2042	$22,000	$20,000	$1,300		$21,000	$18,000
PV 2023-2042	**$250,000**	**$150,000**	**$22,000**	**$14,000**	**$220,000**	**$130,000**
EAV 2023-2042	**$17,000**	**$14,000**	**$1,500**	**$1,300**	**$15,000**	**$12,000**

[a] Rows may not appear to add correctly due to rounding.
[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2023 to 2042. The benefits values use the larger of the two benefits estimates presented in Table ES-9 and Table ES-10, as well as for all other years. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court

for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.
[c] The costs presented in this table are consistent with the costs presented in Chapter 4. To estimate these annualized costs, 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% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

CHAPTER 1: INTRODUCTION AND BACKGROUND

Overview

In this proposed rule, the Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (FIP for the 2015 ozone NAAQS), in accordance with the *Wisconsin* decision, EPA proposes implementation mechanisms to achieve enforceable emissions reductions required to eliminate significant contribution of ozone precursor emissions prior to the 2023 ozone season. The initial phase of proposed emissions reductions will therefore be achieved prior to the August 2, 2024, attainment date for areas classified as Moderate nonattainment for the 2015 ozone NAAQS.[1]

EPA is proposing to promulgate new or revised FIPs for 25 states that include new NO_X ozone season emission budgets for EGU sources, with implementation of these emission budgets beginning in the 2023 ozone season.[2] EPA is also proposing to adjust these states' emission budgets for each ozone season thereafter to maintain the initial stringency of the emissions budget, accounting for retirements and other changes to the fleet over time. EPA is also proposing to extend the Cross-State Air Pollution Rule (CSAPR) NOx Ozone Season Group 3 Trading Program beginning in the 2023 ozone season through the 2025 ozone season. EPA is proposing to establish new emissions budgets for the CSAPR NOx Ozone Season Group 3 Trading Program beginning in the 2026 ozone season, as discussed in Section VII.B.1. of the preamble. EPA is also proposing to retain two states, Iowa and Kansas, in the CSAPR NOx Ozone Season Group 2 Trading Program.

EPA is proposing to promulgate new FIPs for 23 states that include new NO_X emissions limitations for non-electric generating unit (non-EGU) sources, with initial compliance dates for these emissions limitations beginning in 2026.[3]

[1] 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).
[2] In 2023, the 25 states with EGU reduction requirements include AL, AR, DE, IL, IN, KY, LA, MD, MI, MN, MS, MO, NV, NJ, NY, OH, OK, PA, TN, TX, UT, VA, WV, WI, and WY. There are no EGU reductions being required from California, and Oregon's SIP was previously approved.
[3] In 2026, the 23 states with non-EGU reduction requirements include AR, CA, IL, IN, KY, LA, MD, MI, MN, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, WV, WI, and WY. AL, DE, and TN are not linked in 2026, and Oregon's SIP was previously approved.

Consistent with OMB Circular A-4 and EPA's *Guidelines for Preparing Economic Analyses* (2010), this regulatory impact analysis (RIA) presents the benefits and costs of the proposed rule from 2023 through 2042. The estimated monetized benefits are those health benefits expected to arise from reduced $PM_{2.5}$ and ozone concentrations. The estimated monetized costs for EGUs are the costs of installing and operating controls and the increased costs of producing electricity. The estimated monetized costs for non-EGUs are the costs of installing and operating controls to meet the ozone season emissions limits.[4] 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 and (ii) an assessment of how expected compliance with the proposed rule will affect concentrations at nonattainment and maintenance receptors. This chapter contains background information relevant to the proposed 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), which are one component of larger SIP submittals typically required three years after 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).

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

[4] We prepared a non-EGU screening assessment (for more details on the screening assessment, see memorandum titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* in the docket), which includes estimated emissions reductions and costs. These estimates are proxies for (1) non-EGU emissions units that have emission reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs.

Quality Standards (NAAQS).[5] On October 26, 2016, EPA published the CSAPR Update, which finalized Federal Implementation Plans (FIPs) for 22 states that EPA found failed to submit a complete good neighbor State Implementation Plan (SIP) (15 states)[6] or for which EPA issued a final rule disapproving their good neighbor SIP (7 states).[7] The FIPs promulgated for these states included new electric generating unit (EGU) oxides of nitrogen (NO_X) ozone season emission budgets to reduce interstate transport for the 2008 ozone NAAQS.[8] These emission 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. 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.[9]

On March 31, 2021 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.[10] 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.

As described in the preamble of the proposed rule, to reduce interstate emission transport under the authority provided in CAA section 110(a)(2)(D)(i)(I), this rule further limits ozone season (May 1 through September 30) NOx emissions from EGUs in 25 states beginning in 2023 and non-EGUs in 23 states beginning in 2026 using the Interstate Transport Framework. The

[5] CSAPR also addressed interstate transport of fine particulate matter ($PM_{2.5}$) under the 1997 and 2006 $PM_{2.5}$ NAAQS.
[6] Alabama, Arkansas, Illinois, Iowa, Kansas, Maryland, Michigan, Mississippi, Missouri, New Jersey, Oklahoma, Pennsylvania, Tennessee, Virginia, and West Virginia.
[7] Indiana, Kentucky, Louisiana, New York, Ohio, Texas, and Wisconsin.
[8] 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).
[9] In the CSAPR Update, 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.
[10] EPA took the action to address the remand of the CSAPR Update in *Wisconsin v. EPA*, 938 F.3d 303 (D.C. Cir. 2019). The court remanded but did not vacate the CSAPR Update, finding that vacatur of the rule could cause harm to public health and the environment or disrupt the trading program EPA had established and that the obligations imposed by the rule may be appropriate and sustained on remand.

Interstate Transport Framework, the framework developed by 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 ($PM_{2.5}$) 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. The analyses required by these statutes, along with a brief discussion of several executive orders, are presented in Chapter 9. Below we briefly discuss the requirements of Executive Orders 12866 and 13563 and the guidelines of the Office of Management and Budget (OMB) Circular A-4 (U.S. OMB, 2003).

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 proposed rule. OMB Circular A-4 requires analysis of one potential regulatory control alternative more stringent than the proposed rule and one less stringent than the proposed rule. This RIA evaluates the benefits, costs, and certain impacts of a more and a less stringent alternative to the selected alternative in this proposal.

1.1.2 Alternatives Analyzed

For EGUs, the FIP for the 2015 ozone NAAQS would require power plants in the 25 states to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. For non-EGUs, the FIP for the 2015 ozone NAAQS would require units subject to the proposal to meet ozone season emissions limits.

In response to OMB Circular A-4, this RIA analyzes the 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 proposed rule. The more and less stringent alternatives differ from the FIP for the 2015 ozone NAAQS in that they set different EGU NO_X ozone season emission budgets and different dates for compliance with unit-specific emission rate limits for the affected EGUs and cover different industries or emissions units for non-EGUs. Table 1-1 below presents the less stringent alternatives, proposed rule requirements, and more stringent alternatives for EGUs and non-EGUs.

Table 1-1. Regulatory Control Alternatives for EGUs and Non-EGUs

Regulatory Control Alternative	**NO_X Controls Implemented for EGUs within IPM**
Less Stringent Alternative	1) 2023 onwards: Shift generation to minimize costs 2) 2023 onwards: Fully operate existing SCRs during ozone season 3) 2023 onwards: Fully operate existing SNCRs during ozone season 4) In 2023 install state-of-the-art combustion controls 5) In 2028 model run year, impose backstop emission rate limits on coal units greater than 100 MW within the 23-state region that lack SCR controls, forcing units to retrofit or retire. 6) In 2028 model run year, impose backstop emission rate limits on oil/gas steam units greater than 100 MW that operated at a greater than 20% capacity factor historically within the 23-state region that lack SCR controls, forcing units to retrofit or retire.[11]
Proposed Rule	(All Controls above and) 7) In 2026, impose backstop emission rate limits on coal units greater than 100 MW within the 23-state region that lack SCR controls, forcing units to retrofit or retire. 8) In 2026, impose backstop emission rate limits on oil/gas steam units greater than 100 MW that operated at a greater than 20% capacity factor historically within the 23-state region that lack SCR controls, forcing units to retrofit or retire.
More Stringent Alternative	(Controls 1 – 4, 7 and 8 above and) 9) In 2026, impose backstop emission rate limits on all oil/gas steam units greater than 100 MW within the 23-state region that lack SCR controls, forcing units to retrofit or retire.
	NO_X Emissions Limits for Non-EGUs – Emissions Unit Types and Industries
Less Stringent Alternative	1) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas, 2) Kilns in Cement and Cement Product Manufacturing, 3) Boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing, 4) Furnaces in Glass and Glass Product Manufacturing, and
Proposed Rule	(All emissions unit types and industries above and) 5) *Impactful* boilers* in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

[11] The 20% capacity factor cutoff applied is representative of the fleet of O/G steam units assumed to have SCR retrofit potential in its state budgets. In the proposal, EPA defined this segment using 150 tons per season cutoff, which provides a similar size of the O/G steam fleet as the 20% capacity factor value used in this analysis.

Regulatory Control Alternative	NO_X Controls Implemented for EGUs within IPM
More Stringent Alternative	6) (All emissions unit types and industries above and) *All* boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

*Impactful boilers are boilers with design capacity of 100 mmBtu/hr or greater.

For the EGUs, all three alternatives use emission budgets that were developed using uniform control stringency represented by $1,800 per ton of NO_X (2016$) in 2023 and $11,000 per ton of NO_x (2016$) in 2026. The less-stringent alternative imposes unit-specific emission rate limits in the 2028 run year, while the proposed rule and more stringent alternative impose unit-specific emission rate limits in the 2025 run year. For the proposed rule and more stringent alternative, unit-specific emission rate limits are imposed on all coal units within the linked states that are greater than 100 MW and lack SCR controls. Emission rate limits are also imposed on all oil/gas steam units within the linked states that are greater than 100 MW and lack SCR controls that operated at a greater than 20 percent historical capacity factor. In addition to the unit-specific rate limits present in the proposed rule and the less stringent alternative, the more stringent alternative also imposes unit-specific emission rate limits on all oil/gas steam units in the affected states that are greater than 100 MW, lack SCR controls and have operated at below a 20 percent capacity factor historically. See section VII.B. of the preamble, and the EGU NO_X Mitigation Strategies Proposed Rule TSD, in the docket for this rule[12] for further details of these emission budgets.

For non-EGUs, a less stringent alternative would require the emissions limits for all emission units from the proposed policy alternative except for impactful boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. A more stringent alternative would require the emissions limits for all emission units from the proposed policy alternative and all boilers, not just impactful boilers, in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. The emissions limits for the emissions units are the same for each alternative, while the anticipated total number of emissions units to which the limits apply is different between alternatives. See Section VII.C. of the preamble for details on the proposed

[12] Docket ID No. EPA-HQ-OAR-2021-0668

emissions limits. See Chapter 4, Section 4.1.2 of this RIA for more details on the less-stringent and more-stringent alternatives for non-EGUs.

1.1.3 The Need for Air Quality or Emissions 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 soil the property in nearby neighborhoods. Pollution emitted in one state may be transported across state lines and affect air quality in a neighboring state. If bargaining were costless and all property rights were well defined, people would eliminate externalities through bargaining without the need for government regulation.

From an economics perspective, achieving emissions reductions (i.e., by establishing the EGU NO_X ozone-season emissions budgets in this proposal) 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.

1.2 Overview and Design of the RIA

1.2.1 Methodology for Identifying Needed Reductions

In order to apply the first and second steps of the CSAPR 4-step Interstate Transport Framework to interstate transport for the 2015 ozone NAAQS, EPA performed air quality modeling to project ozone concentrations at air quality monitoring sites in 2023, 2026, and 2032. 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 was then repeated using projected ozone concentrations for 2026 and 2032. 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.

To apply the second step of the Interstate Transport Framework, EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2023 and 2026 at downwind receptors. Once quantified, 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.[13] 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, EPA applied a multi-factor test to evaluate cost, available emission reductions, and downwind air quality impacts to determine the appropriate level of NOx control stringency that addresses the impacts of interstate transport on downwind nonattainment or maintenance receptors. EPA used this multi-factor assessment to gauge the extent to which emission reductions are needed, and to ensure any required reductions do not result in over-control.

For EGUs, in identifying levels of uniform control stringency EPA assessed the same NO_X emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available in for EGUs: (1) fully operating existing SCR, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing SNCRs, including both optimizing NO_X

[13] 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, 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.

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). Levels of uniform control stringency were represented by $1,800 per ton of NO_X (2016$) in 2023 and $11,000 per ton of NO_x (2016$) in 2026.[14]

For non-EGUs, in identifying appropriate control strategies EPA developed an analytical framework[15] to evaluate the air quality impacts of potential emissions reductions from non-EGU sources located in the linked upwind states. EPA incorporated air quality modeling information, annual emissions, and information about potential controls to estimate the NO_X emissions reduction potential from non-EGU sources to determine which non-EGU industries, if subject to further control requirements, would have the greatest impact in providing air quality improvements at the downwind receptors. The evaluation was subject to a marginal cost threshold of up to $7,500 per ton (2016$), which EPA determined based on information available to the Agency about existing control device efficiency and cost information. EPA identified emissions unit types in seven industries (see Chapter 4, Section 4.4 for discussion of the approach used to identify the industries) that provide opportunities for NO_X emissions reductions that result in meaningful impacts on air quality at the downwind receptors.

1.2.2 States Covered by the Rule

For EGUs, the FIP for the 2015 ozone NAAQS would require power plants in the 25 states to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update.[16]

- 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 proposed rule: Illinois, Indiana, Kentucky, Louisiana, Maryland,

[14] EGU NO_X Mitigation Strategies Proposed Rule TSD, in the docket for this proposed rule (Docket ID No. EPA-HQ-OAR-2021-0688).
[15] Additional information on the analytical framework is presented in the memorandum titled *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 proposed rulemaking.
[16] As explained in Section VI.C.1 of the preamble, EPA proposes finding that EGU sources within the State of California are sufficiently controlled such that no further emission reductions are needed from them to eliminate significant contribution to downwind states.

Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia.

- Affected EGUs in eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program – Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, 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 five states not currently covered by any CSAPR trading program for seasonal NO_X emissions – Delaware, Minnesota, Nevada, Utah, and Wyoming – would enter the Group 3 trading program in the 2023 control period following the effective date of a final rule.

In addition, EPA is proposing to revise other aspects of the Group 3 trading program to provide improved environmental outcomes and increase compliance, as described in Section VII of the preamble. The proposed rule does not revise the budget stringency and geography of the existing CSAPR NO_X Ozone Season Group 1 trading program.

Aside from the eight states moving from the Group 2 trading program to the Group 3 trading program under the proposed rule, this proposal otherwise leaves unchanged the budget stringency of the existing CSAPR NO_X Ozone Season Group 2 trading program.

For non-EGUs, the proposal also includes NO_X emissions limitations with an initial compliance date of 2026 applicable to certain non-EGU stationary sources in 23 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.

1.2.3 Regulated Entities

The proposal affects EGUs in 26 states and regulates utilities (electric, natural gas, other systems) classified as code 221112 by the North American Industry Classification System (NAICS) and have a nameplate capacity of greater than 25 megawatts (MWe). In addition, the rule affects certain non-EGUs in 23 states in the following industries, as defined by 4-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; Basic Chemical Manufacturing, 3251; Petroleum and Coal Products Manufacturing, 3241; Pulp, Paper, and Paperboard Mills, 3221. For additional discussion of the non-EGUs affected, see Section VII.C. of the preamble.

1.2.4 Baseline and Analysis Years

As described in the preamble, EPA aligns implementation of this proposal with relevant attainment dates for the 2015 ozone NAAQS. The initial phase of proposed emissions reductions will therefore be achieved prior to the August 2, 2024 attainment date for areas classified as Moderate nonattainment for 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 year of 2023, taking into account currently on-the-books Federal regulations, substantial Federal regulatory proposals, enforcement actions, state regulations, population, and where possible, economic growth.[17] 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 the proposal.

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 in 2026 are important because it is in this period that additional NOx control technologies are expected to be installed where upwind linkage to downwind receptors persists.

[17] 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. For this proposal, the future-year emissions estimates for onroad mobile sources represent all national control programs known at the time of modeling including rules newly added in MOVES3: the Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (HDGHG) – Phase 2 and the Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule. Other finalized rules incorporated into the onroad mobile source emissions estimates include: Tier 3 Standards (March 2014), the Light-Duty Greenhouse Gas Rule (March 2013), Heavy (and Medium)-Duty Greenhouse Gas Rule (August 2011), the Renewable Fuel Standard (February 2010), the Light Duty Greenhouse Gas Rule (April 2010), the Corporate-Average Fuel Economy standards for 2008-2011 (April 2010), the 2007 Onroad Heavy-Duty Rule (February 2009), and the Final Mobile Source Air Toxics Rule (MSAT2) (February 2007).

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 of $11,000 for EGUs and a marginal cost threshold of $7,500 for non-EGUs) includes additional EGU controls and estimated non-EGU emissions reductions. See Section VI.D.4 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.

1.2.5 Emissions Controls, Emissions, and Cost Analysis Approach

EPA estimated the control strategies and compliance costs of the rule 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_X 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_X emissions changes during the May through September ozone season and year-round, as well as annual emissions changes in $PM_{2.5}$, SO_2, and carbon dioxide (CO_2) due to changes in power sector operation.

In addition, to identify appropriate control strategies for non-EGU sources to achieve NO_X emissions reductions that would result in meaningful air quality improvements in downwind areas, EPA developed an analytical framework to evaluate the air quality impacts of potential emissions reductions from non-EGU sources located in the linked upwind states. EPA incorporated air quality modeling information, annual emissions, and available information about potential to determine which industries, if subject to further control requirements, would have the greatest impact in providing air quality improvements at the downwind receptors. This evaluation was subject to a marginal cost threshold of up to $7,500 per ton, which EPA determined based on information available to the Agency about existing control device efficiency and cost information. EPA used the control strategy tool (CoST)[18], the control measures database[19], and the 2019 emissions inventory with the analytical framework to prepare a screening assessment for 2026. Additional information on the analytical framework is included in the memorandum titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026*.[20] This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. We used CoST to identify emissions units, emissions reductions, and costs to include in a proposed FIP; however, CoST was designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. The estimates from CoST identify proxies for (1) non-EGU emissions units that have emission reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units.

1.2.6 Benefits Analysis Approach

Implementing the FIP for the 2015 ozone NAAQS proposal is expected to reduce emissions of $PM_{2.5}$, NO_X and SO_2 throughout the year. Because NO_X and SO_2 are also precursors to formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects. For more details on associated estimated benefits, see Chapter 5.

1.3 Organization of the Regulatory Impact Analysis

This RIA is organized into the following remaining chapters:

- *Chapter 2: 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.

[18] Further information on CoST can be found at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.
[19] The control measures database is available at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.
[20] The costs did not include monitoring, recordkeeping, report, or testing 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 screening assessment used to estimate costs for the non-EGU industries.
- *Chapter 5: Benefits*. The chapter presents the health-related benefits of the ozone-related air quality improvements.
- *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 potential environmental justice populations.
- *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

Overview

This chapter discusses important aspects of the regulated industries that relate to the proposed rule with respect to the interstate transport of emissions of nitrogen oxides (NO_X) 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 proposed 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 proposal.

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 2020. 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 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 in 2014 and 2020.

In 2020 the power sector consisted of over 23,417 generating units with a total capacity[1] of 1,116 GW, an increase of 47 GW (or 4 percent) from the capacity in 2014 (1,068 GW). The 47 GW increase consisted primarily of natural gas fired EGUs (54 GW), and wind (54 GW) and solar generators (38 GW), and the retirement/re-rating of 84 GW of coal capacity. Substantially smaller net increases and decreases in other types of generating units also occurred.

Table 2-1. Total Net Summer Electricity Generating Capacity by Energy Source, 2014 and 2020

	2014		2020		Change Between 2014 and 2020	
Energy Source	**Net Summer Capacity (MW)**	**% Total Capacity**	**Net Summer Capacity (MW)**	**% Total Capacity**	**% Increase**	**Capacity Change (MW)**
Coal	299,094	28%	215,554	19%	-28%	-83,540
Natural Gas	432,150	40%	485,807	44%	12%	53,657
Nuclear	98,569	9%	96,501	9%	-2.1%	-2,069
Hydro	102,162	9.56%	102,941	9.23%	0.8%	778
Petroleum	41,135	3.85%	27,569	2.47%	-33%	-13,566
Wind	64,232	6.01%	118,379	10.61%	84%	54,147
Solar	10,323	0.97%	48,054	4.31%	365%	37,731
Other Renewable	16,049	2%	15,522	1%	-3%	-527
Misc	4,707	0.44%	5,355	0.48%	14%	648
Total	1,068,422	100%	1,115,681	100%	4%	47,259

Note: This table presents generation capacity. Actual net generation is presented in Table 2-2.
Source: EIA. Electric Power Annual 2014 and 2020, Table 4.3

The 4 percent increase in generating capacity is the net impact of newly built generating units, retirements of generating units, and a variety of increases and decreases to the nameplate

[1] 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).

capacity of individual existing units due to changes in operating equipment, changes in emission controls, etc. During the period 2014 to 2020, a total of 173 GW of new generating capacity was built and brought online, and 123 GW of existing units were retired. The net effect of the re-rating of existing units reduced the total capacity by 2.8 GW. The overall net change in capacity was an increase of 47 GW, as shown in Table 2-1.

The newly built generating capacity was primarily natural gas (67.1 GW), which was partially offset by gas retirements (23.6 GW of gas steam retirements, 5.2 GW of combined cycle and 7.3 GW of combustion turbine retirements for a total of 36.1 GW of gas retirements). Wind capacity was the second largest type of new builds (59 GW), followed by solar (41 GW). The largest decline was from coal retirements and re-rating, which amounted to 84 GW over this period. The overall mix of newly built and retired capacity, along with the net effect, is shown in Figure 2-1. The data for Figure 2-1 is from the EIA Preliminary Monthly Generator Inventory. Figure 2-1 also shows wind and solar retirements of 1,060 MW.

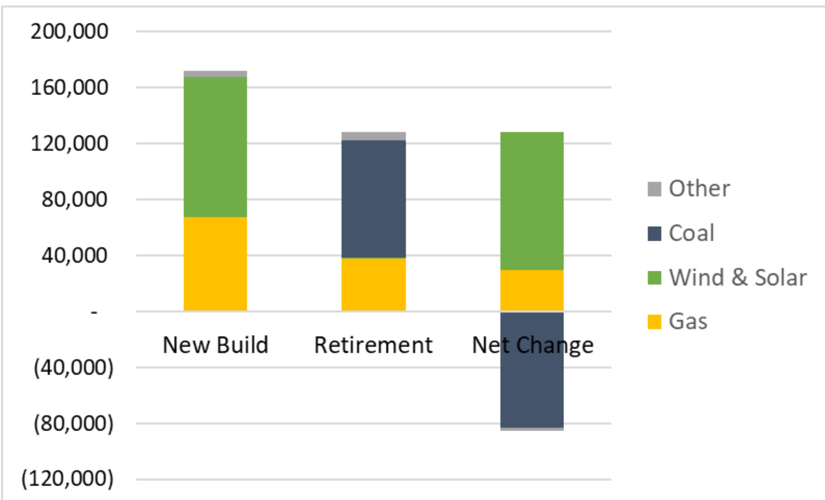

Figure 2-1. National New Build and Retired Capacity (MW) by Fuel Type, 2014-2020

The information in Table 2-1 and Figure 2-1 present information about the generating capacity in the entire U.S. The proposed Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (FIP for the 2015 ozone NAAQS), however, directly affects EGUs in 25 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 2-2 shows the mix of generating capacity for each region. In 2020, the overall capacity in the FIP for the 2015 Ozone NAAQS Region is 60 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 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 (13 percent). The share of natural gas in the FIP for the 2015 Ozone NAAQS Region is 46 percent as compared to 39 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 FIP for the 2015 Ozone NAAQS Region.

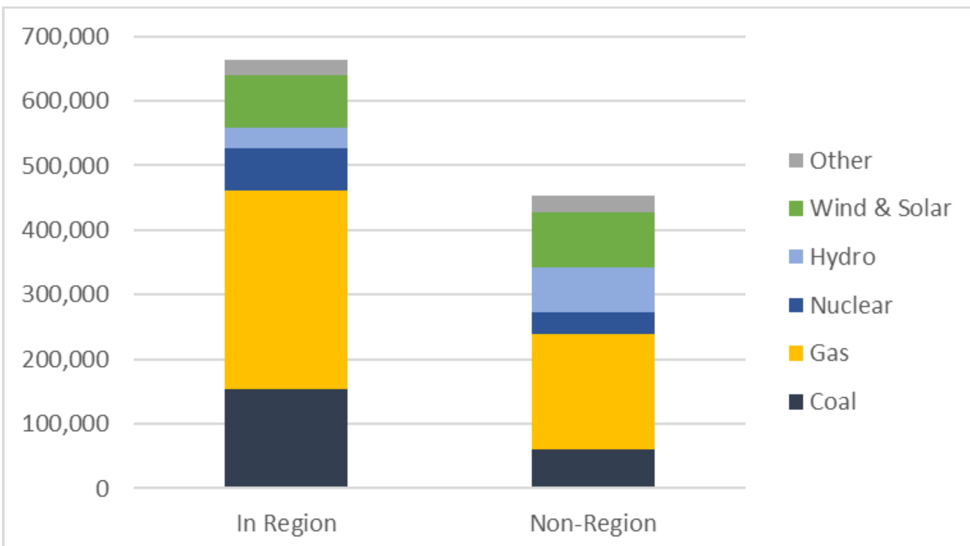

Figure 2-2. Regional Differences in Generating Capacity (MW), 2020

Source: Form EIA-860. Note: "Other" includes petroleum, geothermal, other renewable, waste materials and miscellaneous.

In 2020, electric generating sources produced a net 4,049TWh to meet national electricity demand, which was roughly flat from 2014. As presented in Table 2-2, 60 percent of electricity in 2020 was produced through the combustion of fossil fuels, primarily coal and natural gas, with natural gas accounting for the largest single share. Although the share of the total generation from fossil fuels in 2020 (60 percent) was only modestly smaller than the total fossil share in 2014 (67 percent), the mix of fossil fuel generation changed substantially during that period. Coal generation declined by 51 percent and petroleum generation by 42 percent, while natural gas generation increased by 44 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 5 percent of the mix in 2014 to 12 percent in 2020.

Table 2-2. Net Generation in 2014 and 2020 (Trillion kWh = TWh)

	2014		**2020**		**Change Between '14 and '20**	
	Net Generation (TWh)	**Fuel Source Share**	**Net Generation (TWh)**	**Fuel Source Share**	**Net Generation Change (TWh)**	**% Change in Net Generation**
Coal	1,582	39%	773	19%	-808	1496%
Natural Gas	1,127	27%	1,624	40%	498	-907%
Nuclear	797	19%	790	20%	-7	13%
Hydro	253	6%	280	7%	27	-60%
Petroleum	30	1%	17	0%	-13	24%
Wind	182	4%	338	8%	156	-289%
Solar	18	0%	131	3%	102	-136%
Other Renewable	91	2%	71	2%	-9	-44%
Misc	25	1%	25	1%	-1	3%
Total	4,105	100%	4,049	100%	-56	100%

Source: EIA 2014 and 2020 Electric Power Annual, Tables 3.1

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 operates 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 compose 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.

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. Many of the largest gas units are gas-fired steam-generating EGUs.

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)
COAL							
0 – 24	35	7%	46	11	372	0%	11,027
25 – 49	30	6%	35	37	1,096	1%	11,638
50 – 99	22	4%	37	75	1,653	1%	11,688
100 - 149	36	7%	49	121	4,362	2%	11,153
150 - 249	59	12%	50	196	11,560	6%	10,908
250 - 499	120	24%	41	373	44,729	23%	10,690
500 - 749	132	27%	40	608	80,256	40%	10,325
750 - 999	49	10%	37	826	40,485	20%	10,125
1000 - 1500	11	2%	42	1,264	13,903	7%	9,834
Total Coal	494	100%	42	402	198,416	100%	10,703
NATURAL GAS							
0 – 24	13,616	69%	29	4	60,851	8%	6,356
25 – 49	1,713	9%	33	38	65,603	8%	7,000
50 – 99	1,782	9%	28	71	126,171	16%	7,202
100 - 149	802	4%	25	122	98,217	12%	4,935
150 - 249	1,365	7%	16	181	246,875	31%	6,235
250 - 499	394	2%	19	327	128,773	16%	6,115
500 - 749	57	0%	37	584	33,265	4%	7,985
750 - 1000	42	0%	43	879	36,932	5%	9,825
Total Gas	19,771	100%	28	40	796,687	100%	6,439

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. Table is limited to coal-steam units in operation in 2018 or earlier and excludes those units in NEEDS with planned retirements in 2020 or 2021.

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 2-3 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 2-3 also includes the distribution of generation, which is similar to the distribution of capacity.

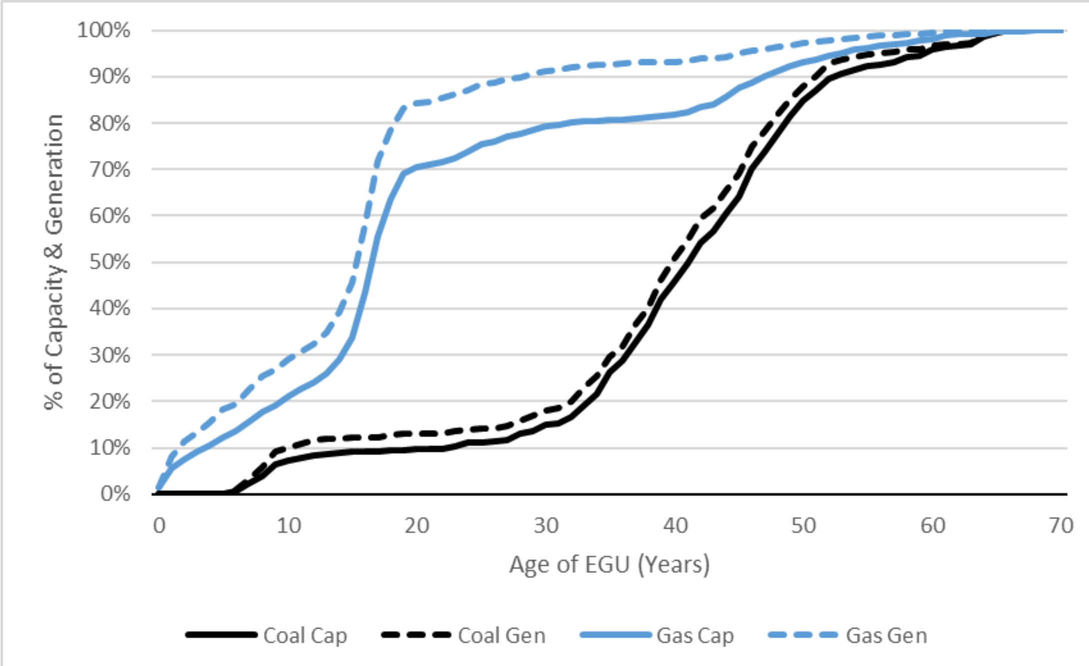

Figure 2-3. Cumulative Distribution in 2019 of Coal and Natural Gas Electricity Capacity and Generation, by Age

Source: eGRID 2019 (March 2021 release from EPA eGRID website). Figure presents data from generators that came online between 1949 and 2019 (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. Figure is limited to coal-steam units in NEEDS v6 in operation in 2019 or earlier.

The locations of existing fossil units in EPA's National Electric Energy Data System (NEEDS) v.6 are shown in Figure 2-4.

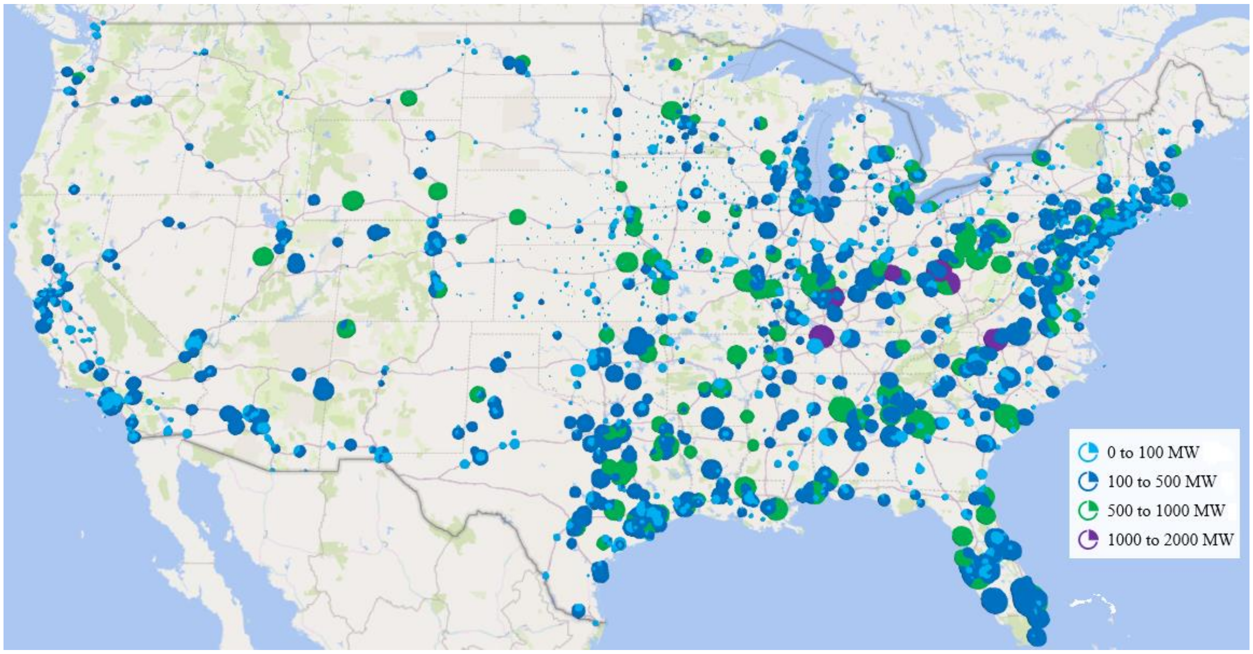

Figure 2-4. Fossil Fuel-Fired Electricity Generating Facilities, by Size

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,[2] 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

[2] 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.

regional operator;[3] in others, individual utilities[4] coordinate the operations of their generation, 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

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[3] For example, PMJ Interconnection, LLC, Western Area Power Administration (which comprises 4 sub-regions).
[4] For example, Los Angeles Department of Power and Water, Florida Power and Light.

to a third of the total electricity produced[5] (see Table 2-4). Some of these uses are highly 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 2014 and 2020.

Table 2-4. Total U.S. Electric Power Industry Retail Sales, 2014 and 2020 (billion kWh)

		2014		2020	
		Sales/Direct Use (Billion kWh)	**Share of Total End Use**	**Sales/Direct Use (Billion kWh)**	**Share of Total End Use**
Sales	Residential	1,407	36%	1,465	38%
	Commercial	1,352	35%	1,287	34%
	Industrial	998	26%	959	24%
	Transportation	8	0%	7	0%
Total		3,765	96%	3,718	96%
Direct Use		139	4%	139	4%
Total End Use		**3,903**	**100%**	**3,856**	**100%**

Source: Table 2.2, EIA Electric Power Annual, 2014 and 2020
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

[5] Transportation (primarily urban and regional electrical trains) is a fourth ultimate customer category which accounts less than one percent of electricity consumption.

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 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 2020, the national average retail electricity price (all sectors) was 10.59 cents/KWh, with a range from 7.51 cents (Louisiana) to 27.55 cents (Hawaii).[6]

Average national retail electricity prices decreased between 2014 and 2020 by 8 percent in real terms (2019$).[7] The amount of decrease differed for the three major end use categories (residential, commercial and industrial). National average industrial prices decreased the most (14 percent), and residential prices decreased the least (4 percent). The real year prices for 2014 through 2020 are shown in Figure 2-5.

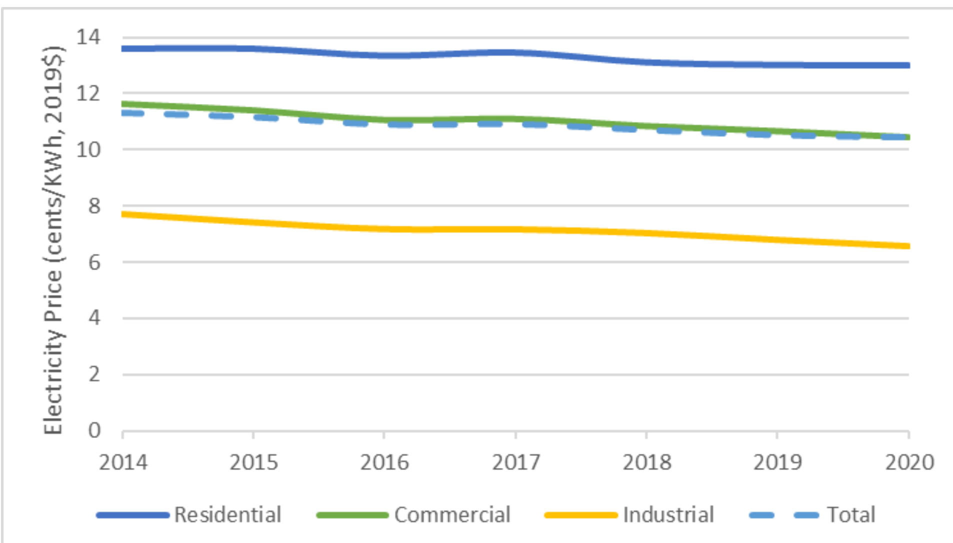


Figure 2-5. Real National Average Electricity Prices (including taxes) for Three Major End-Use Categories

Source: EIA Monthly Energy Review (October 2021), Table 9.8.

[6] EIA State Electricity Profiles with Data for 2020 (http://www.eia.gov/electricity/state/)
[7] All prices in this section are estimated as real 2019 prices adjusted using the GDP implicit price deflator unless otherwise indicated.

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 electricity prices declined in 2019 and 2020. The increase in nominal electricity prices for the major end use categories, as well as increases in the GDP price and CPI-U indices for comparison, are shown in Figure 2-6.

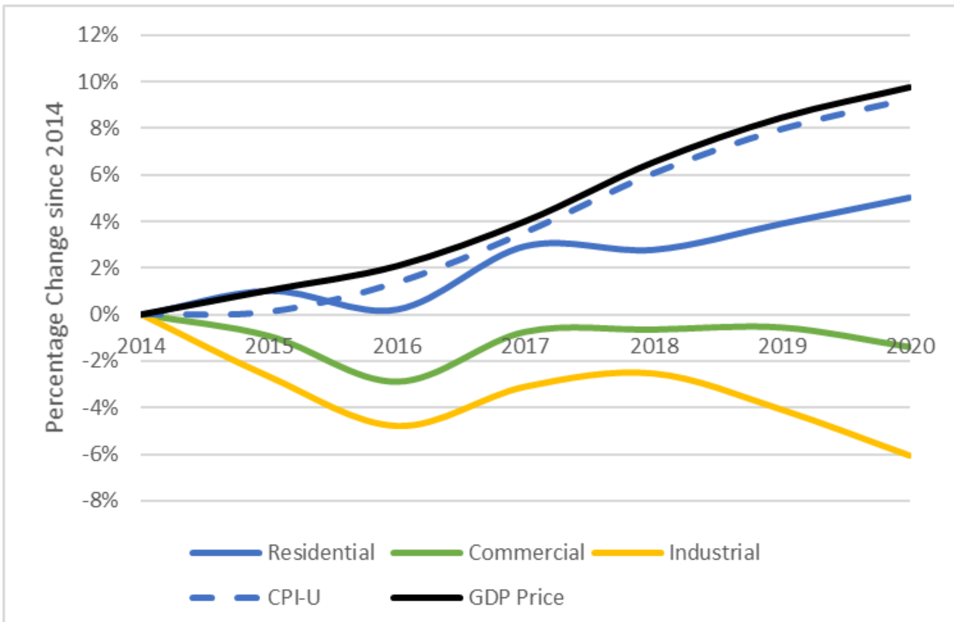


Figure 2-6. Relative Increases in Nominal National Average Electricity Prices for Major End-Use Categories (including taxes), With Inflation Indices

Source: EIA Monthly Energy Review (October 2021), Table 9.8.

For a longer-term perspective, Figure 2-7 shows real (2019$) electricity prices for the three major customer categories since 1960, and Figure 2-8 shows the relative change in real electricity prices relative to the prices since 1960. As can be seen in the figures, the price for industrial customers has always been lower than for either residential or commercial customers, but the industrial price has been more volatile. While the industrial real price of electricity in 2020 was 11 percent lower than in 1960, residential and commercial real prices are 26 percent and 35 percent lower respectively than in 1960.

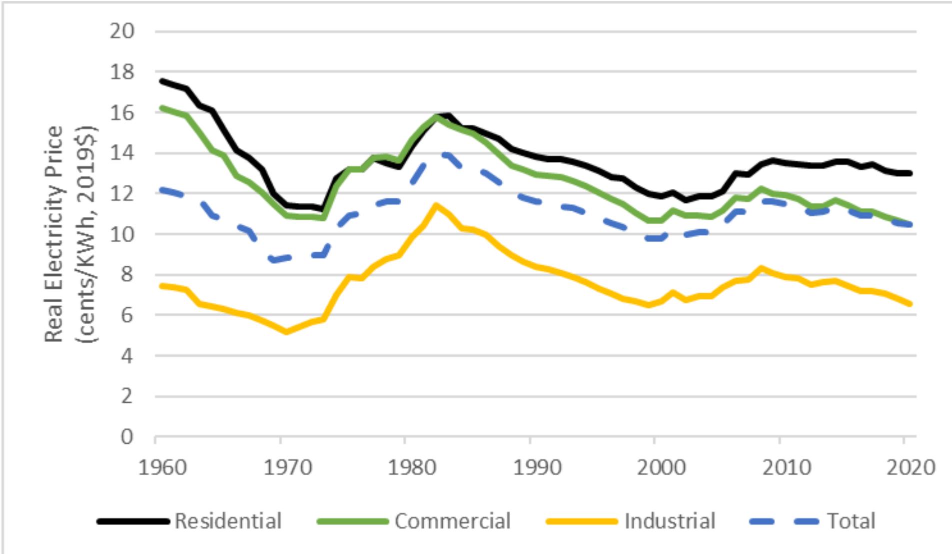


Figure 2-7. Real National Average Electricity Prices for Three Major End-Use Categories (including taxes), 1960-2020 (2019$)

Source: EIA Monthly Energy Review, October 2021, Table 9.8

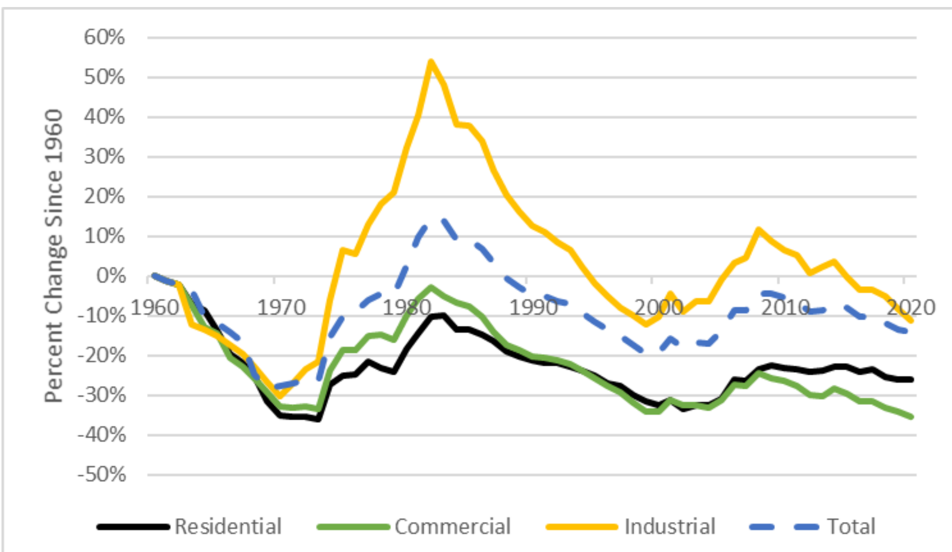


Figure 2-8. Relative Change in Real National Average Electricity Prices (2019$) for Three Major End-Use Categories (including taxes)

Source: EIA Monthly Energy Review, October 2021, Table 9.8.

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[8] for the three major fossil fuels used in electricity generation: coal, natural gas and residual fuel oil. 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 residual fuel oil also decreased by 55 percent, and petroleum products declined as an EGU fuel (in 2020 petroleum products generated 0.4% 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 2-9 shows the relative changes in real price of all 3 fossil fuels between 2000 and 2020.

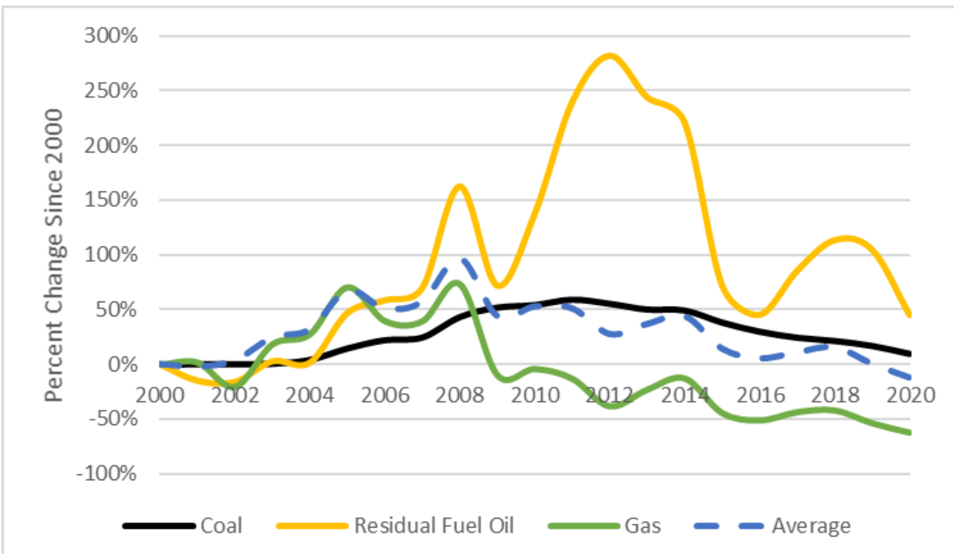


Figure 2-9. Relative Real Prices of Fossil Fuels for Electricity Generation; Change in National Average Real Price per MMBtu Delivered to EGU

Source: EIA Monthly Energy Review, October 2021, Table 9.9.

2.3.3 Changes in Electricity Intensity of the U.S. Economy from 2014 to 2020

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2014 and 2020 is that while total net generation decreased by 1.4 percent over that period, the demand growth for generation was lower than both the population growth (4 percent)

[8] Fuel prices in this section are all presented in terms of price per MMBtu to make the prices comparable.

and real GDP growth (10 percent). Figure 2-10 shows the growth of electricity generation, population and real GDP during this period.

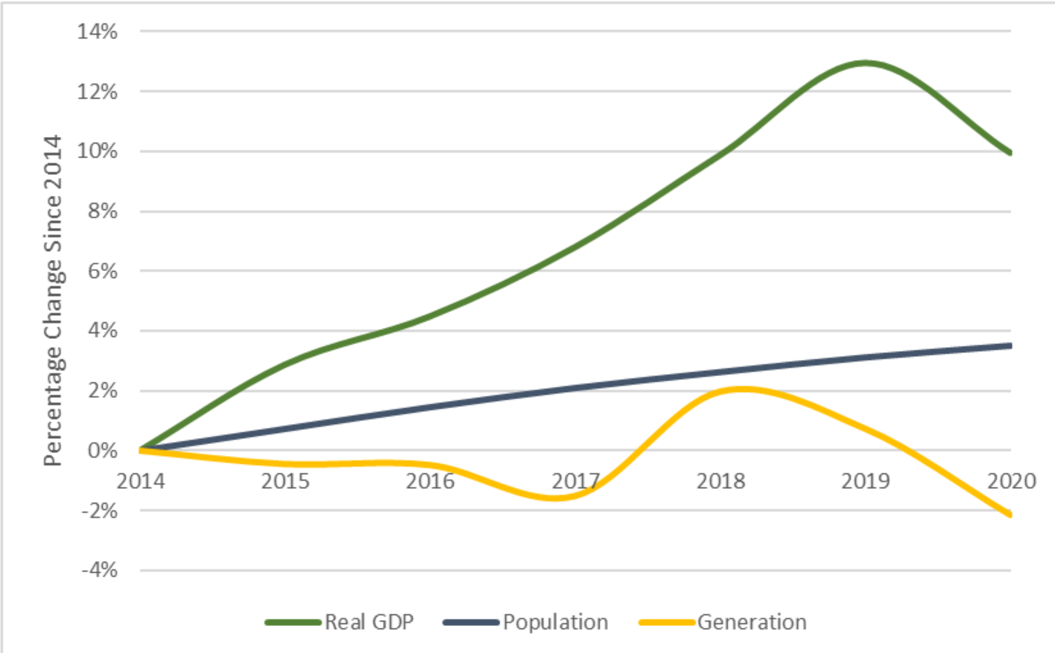


Figure 2-10. Relative Growth of Electricity Generation, Population and Real GDP Since 2014

Sources: Generation: U.S. EIA Monthly Energy Review, October 2021. Table 7.2a Electricity Net Generation: Total (All Sectors). Population: U.S. Census. Real GDP: 2021 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 2019 dollar of output) during 2014 to 2020. On a per capita basis, real GDP per capita grew by 6 percent between 2014 and 2020. At the same time electricity generation per capita decreased by 5 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 11 percent. These relative changes are shown in Figure 2-11.

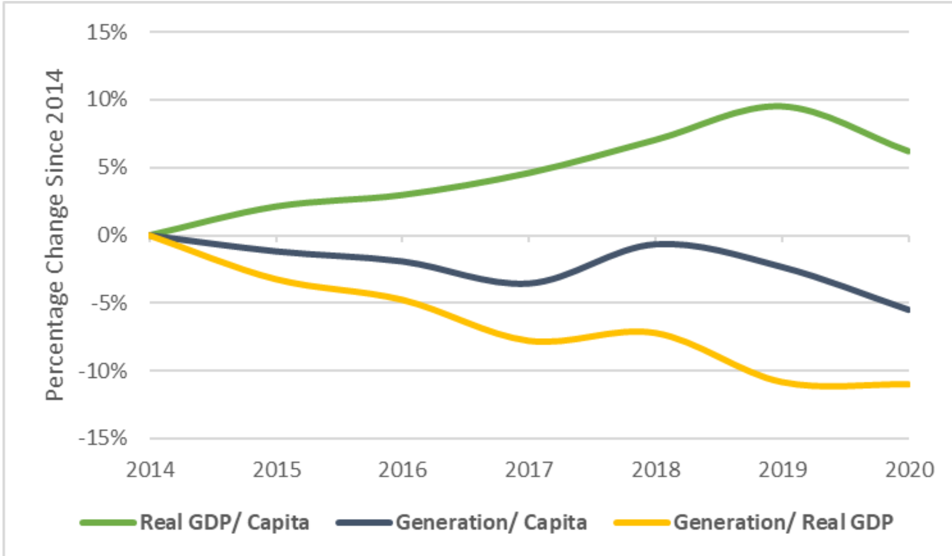


Figure 2-11. Relative Change of Real GDP, Population and Electricity Generation Intensity Since 2014

Sources: Generation: EIA Monthly Energy Review, October 2021. Table 7.2a Electricity Net Generation: Total (All Sectors). Population: U.S. Census. Real GDP: 2021 Economic Report of the President, Table B-3.

2.4 Deregulation and Restructuring

The process of restructuring and deregulation of wholesale and retail electricity markets has changed the structure of the electric power industry. In addition to reorganizing asset management between companies, restructuring sought a functional unbundling of the generation, transmission, distribution, and ancillary services the power sector has historically provided, with the aim of enhancing competition in the generation segment of the industry.

Beginning in the 1970s, government policy shifted against traditional regulatory approaches and in favor of deregulation for many important industries, including transportation (notably commercial airlines), communications, and energy, which were all thought to be natural monopolies (prior to 1970) that warranted governmental control of pricing. However, deregulation efforts in the power sector were most active during the 1990s. Some of the primary drivers for deregulation of electric power included the desire for more efficient investment choices, the economic incentive to provide least-cost electric rates through market competition, reduced costs of combustion turbine technology that opened the door for more companies to sell power with smaller investments, and complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes. Deregulation and market restructuring in the power sector involved the divestiture of generation from utilities, the formation of organized wholesale spot energy markets with economic mechanisms for the rationing of scarce transmission resources during periods of peak demand, the introduction of retail choice programs, and the establishment of new forms of market oversight and coordination.

The pace of restructuring in the electric power industry slowed significantly in response to market volatility in California and financial turmoil associated with bankruptcy filings of key energy companies. By the end of 2001, restructuring had either been delayed or suspended in eight states that previously enacted legislation or issued regulatory orders for its implementation (shown as “Suspended” in Figure 2-12). Eighteen other states that had seriously explored the possibility of deregulation in 2000 reported no legislative or regulatory activity in 2001 (EIA, 2003) (“Not Active” in Figure 2-12). Currently, there are 15 states plus the District of Columbia where price deregulation of generation (restructuring) has occurred (“Active” in Figure 2-12). Power sector restructuring is more or less at a standstill; by 2010 there were no active proposals under review by the Federal Energy Regulatory Commission (FERC) for actions aimed at wider restructuring, and no additional states have begun retail deregulation activity since that time.

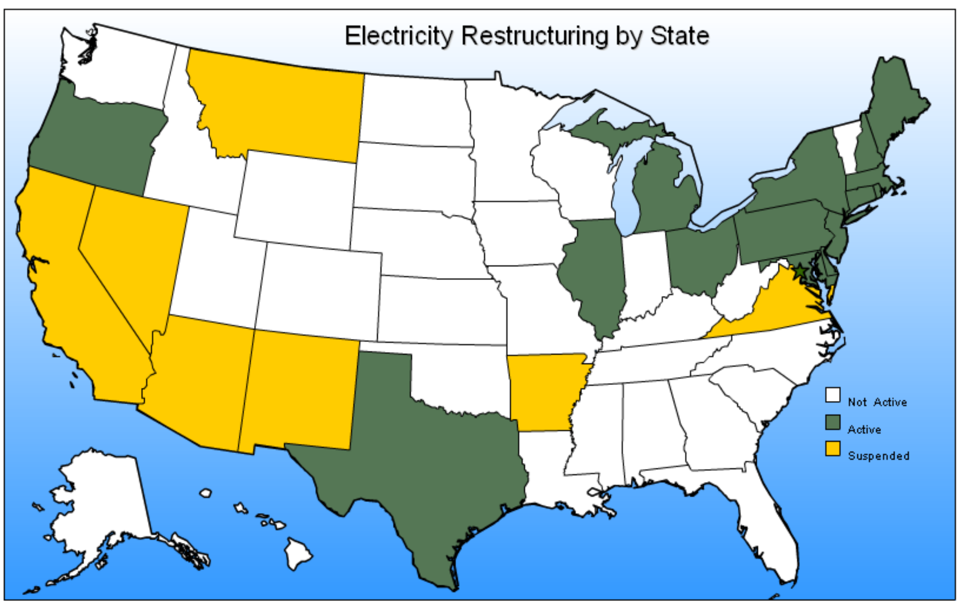


Figure 2-12. Status of State Electricity Industry Restructuring Activities

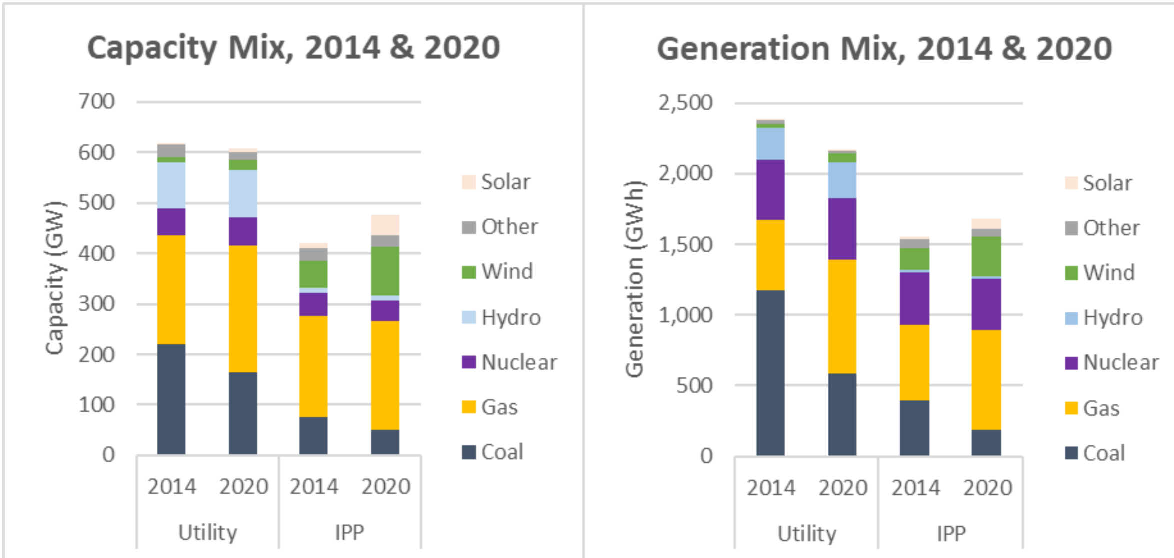
Source: EIA 2010. “Status of Electricity Restructuring by State.” Available online at: <http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html>.

One major effect of the restructuring and deregulation of the power sector was a significant change in type of ownership of electricity generating units in the states that deregulated prices. Throughout most of the 20th century electricity was supplied by vertically integrated regulated utilities. The traditional integrated utilities provided generation, transmission and distribution in their designated areas, and prices were set by cost-of-service regulations set by state government agencies (e.g., Public Utility Commissions). Deregulation and restructuring resulted in unbundling of the vertical integration structure. Transmission and distribution continued to operate as monopolies with cost-of-service regulation, while generation shifted to a mix of ownership affiliates of traditional utility ownership and some generation owned and operated by competitive companies known as Independent Power Producers (IPPs). The resulting generating sector differed by state or region, as the power sector adapted to the restructuring and deregulation requirements in each state.

By the year 2000, the major impacts of adapting to changes brought about by deregulation and restructuring during the 1990s were nearing completion. In 2014, traditional utilities owned 58 percent of U.S. generating capacity (MW) while IPPs[9] owned 39 percent of U.S. generating capacity, respectively. The mix of electricity generated (MWh) was more heavily weighted towards the utilities, with a distribution in 2014 of 61 percent, and 39 percent for IPPs. In 2020, the share of capacity (54 percent utility, 43 percent IPPs) and generation (54 percent utility, 42 percent IPP) has remained relatively stable relative to 2014 levels.

The mix of capacity and generation for each of the ownership types is shown in Figures 2-13 (capacity) and 2-14 (generation). A portion of the shift of capacity and generation is due to sales and transfers of generation assets from traditional utilities to IPPs, rather than strictly the result of newly built units.

[9] IPP data presented in this section include both combined and non-combined heat and power plants.



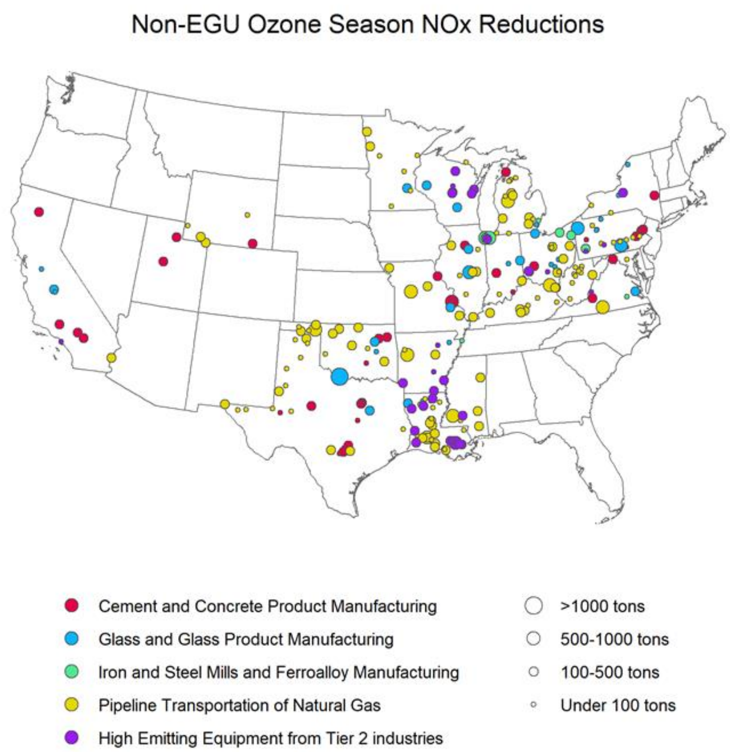
Figures 2-13. and 2-14. Capacity and Generation Mix by Ownership Type, 2014 & 2020

Source: Table 3.2, EIA Electric Power Annual, 2014 and 2020

2.5 Industrial Sectors Overview

The proposed regulation establishes various ozone season NO_x 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 boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; for furnaces in Glass and Glass Product Manufacturing; and for impactful boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.[10] Figure 2-15 shows the locations[11] of the estimated non-EGU emissions reductions by industry. A description of the Tier 1 and Tier 2 industries, as well as a discussion of how the reductions were estimated are in Chapter 4, Section 4.4. 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 non-EGU Sectors TSD in the docket.

[10] Impactful boilers are boilers with design capacity of 100 mmBtu/hr or greater.
[11] Facility location information is based on the 2019 inventory, which is discussed in Chapter 4, Section 4.5.4.



State	Cement and Concrete Product Manufacturing	Glass and Glass Product Manufacturing	Iron and Steel Mills and Ferroalloy Manufacturing	Pipeline Transportation of Natural Gas	High Emitting Equipment from Tier 2 industries	Total
LA	0	206	0	3,915	2,649	6,769
TX	1,234	1,470	0	1,736	0	4,440
OK	586	190	0	2,799	0	3,575
PA	888	1,379	438	427	152	3,284
IN	468	338	1,829	152	388	3,175
MO	1,296	227	0	1,581	0	3,103
OH	116	451	847	1,198	179	2,790
MI	371	50	38	2,272	0	2,731
IL	234	901	0	1,316	0	2,452
KY	0	0	0	2,291	0	2,291
WI	0	677	0	0	1,472	2,150
MS	0	0	0	1,577	184	1,761
CA	1,162	299	0	137	68	1,666
AR	0	47	6	868	732	1,654
VA	398	174	92	801	98	1,563
WV	230	0	0	751	0	982
WY	446	0	0	380	0	826
UT	520	0	0	237	0	757
MN	0	115	0	558	0	673
NY	142	141	0	106	111	500
MD	0	0	0	45	0	45

Figure 2-15. Geographical Distribution of Non-EGU Ozone Season NOx Reductions and Summary of Reductions by Industry and by State

2.5.1 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 alumino-ferrites. 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 ferrifrous (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.

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 NOx 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 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 NOx 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 NOx formation. In the secondary combustion zone, however, lower gas-phase temperatures suppress thermal NOx formation. The temperatures at which these kilns operate influence what NOx 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 NOx emissions; for example, a high thermal efficiency equates to less heat and fuel being consumed and, therefore, less NOx 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 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 additional, 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).

2.5.2 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.

Blast furnaces are the primary site of iron making at integrated facilities where iron ore is converted into more pure and uniform iron. Blast furnaces are tall steel vessels lined with heat-resistant brick (AISI, 1989). They range in size from 23 to 45 feet in diameter and are over 100 feet tall (Hogan and Koelble, 1996; Lankford et al., 1985). Conveyor systems of carts and ladles carry inputs and outputs to and from the blast furnace.

Steel making is carried out in basic oxygen furnaces or electric arc furnaces (EAFs), while iron making is only carried out in blast furnaces. Basic oxygen furnaces are the standard steel making furnace used at integrated mills. EAFs are the standard furnace at mini-mills since they use scrap metal efficiently on a small scale. Open hearth furnaces were used to produce steel prior to 1991 but have not been used in the United States since that time.

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 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.

2.5.3 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 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 of the NOx 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 in order 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.

2.5.4 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.

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.

2.5.5 Tier 2 Industries

This proposed rulemaking includes NO_x emission limits on the most impactful boilers from an additional three industries. The first 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 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 third 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.

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).

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CHAPTER 3: AIR QUALITY IMPACTS

Overview

This Chapter describes the impacts on ozone concentrations in 2023 and 2026 of the three alternative control cases (i.e., proposal case, less stringent case, and more stringent case) analyzed in this RIA. First, we describe the methods for developing spatial fields of air quality concentrations for the baseline and regulatory control alternatives in 2023 and 2026. These spatial fields provide the air quality inputs to potentially calculate health benefits from reduced concentrations of $PM_{2.5}$ and ozone for the proposed Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (FIP for the 2015 ozone NAAQS). In brief, the spatial fields were constructed based on a method that utilizes ozone 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 concentrations. This method, as described in Appendix 3A, was originally developed to support the RIA for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (U.S. EPA 2019) and, most recently, the RIA for the Revised CSAPR Update final rule.

Second, we provide the estimated impacts on projected 2023 and 2026 ozone design values expected to result from the EGU and non-EGU regulatory control alternatives analyzed in this RIA. Because of timing constraints, we were not able to perform full-scale photochemical air quality modeling for these cases to quantify the ozone impacts. Rather, we applied the Air Quality Assessment Tool (AQAT) that was used to inform the air quality analyses in Step 3 of the 4-step transport framework as the method for estimating the impacts of the three control cases.[1] The methodology for estimating ozone impacts and the resulting impacts on ozone design values at individual receptors are provided in Appendix 3B. In Section 3.1 we describe the air quality modeling platform used for this proposed FIP; in Section 3.2 we describe the method for processing air quality modeling outputs to create spatial fields for estimating benefits; in Section 3.3 we describe how the method was applied in the proposed FIP for the 2015 ozone NAAQS; in Section 3.4 we present maps showing the impacts on ozone concentrations of each of the

[1] See the Ozone Policy Analysis Proposed Rule TSD which can be found in the docket for this proposed rule for details on the construction of the ozone AQAT.

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.

3.1 Air Quality Modeling Platform

The air quality modeling for the proposed FIP utilized a 2016-based modeling platform which included meteorology and base year emissions from 2016 and projected emissions for 2023 and 2026. The air quality modeling included photochemical model simulations for a 2016 base year and 2023 and 2026 future years to provide hourly concentrations of ozone nationwide. In addition, source apportionment modeling was performed for 2026 to quantify the contributions to ozone from NO_X emissions from electric generating units (EGUs) and from point sources other than EGUs (i.e., non-EGUs) on a state-by-state basis. As described below, the modeling results for 2016, 2023, and 2026, in conjunction with emissions data for the 2023 and 2026 baseline and regulatory control alternatives, were used to construct the air quality spatial fields that reflect the influence of emissions changes between the baseline and the regulatory control alternatives.

The air quality model simulations (*i.e.,* model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx) version 7.10 (Ramboll Environ, 2021). Our 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 shown in Figure 3-1.

Figure 3-1. Air Quality Modeling Domain

The contributions to ozone from EGU and, separately, from non-EGU emissions in individual states were modeled using a tool called "source apportionment." In general, source apportionment modeling quantifies the air quality concentrations formed from individual, user-defined groups of emissions sources or "tags". These source tags are tracked through the transport, dispersion, chemical transformation, and deposition processes within the model to obtain hourly gridded[2] contributions from the emissions in each individual tag to hourly modeled concentrations. Thus, the source apportionment method can be used to provide an estimate of the effect of changes in emissions from each group of emissions sources (*i.e.*, each tag) to changes in ozone concentrations. For this analysis we applied outputs from source apportionment modeling for ozone using the 2026 modeled case to obtain the contributions from EGUs and non-EGUs NO_X emissions in each state to ozone concentrations in each 12 x 12 km model grid cell nationwide. Ozone contributions were modeled using the Ozone Source Apportionment Technique/Anthropogenic Precursor Culpability Assessment (OSAT/APCA) tool (Ramboll, 2021). The source apportionment modeling was performed for the period April through September to provide data for developing spatial fields for the April through September

[2] Hourly contribution information is provided for each grid cell to provide spatial patterns of the contributions from each tag.

maximum daily eight-hour (MDA8) (i.e., AS-MO3) average ozone concentration exposure metric.[3,4]

3.2 Applying Modeling Outputs to Create Spatial Fields

In this section we describe the method for creating spatial fields of AS-MO3 based on the 2016, 2023, and 2026 modeling. The foundational data include (1) ozone concentrations in each model grid cell from the 2023 and 2026 baseline modeling, (2) contributions in 2026 from EGUs and non-EGUs emissions from each state in each model grid cell[5], (3) 2023 and 2026 emissions for EGUs and non-EGUs that were input to the contribution modeling, and (4) the EGU and non-EGU emissions for each of the regulatory scenarios. The method to create spatial fields is based on scaling ratios that apply emissions changes between the baseline and the control case to the baseline contributions, described below.

To create the spatial fields for each future emissions scenario the 2026 state-sector source apportionment modeling outputs are used in combination with the 2023 and 2026 EGU and non-EGU NO_x emissions for each scenario. Contributions from each state-sector contribution "tag" were scaled based on the ratio of emissions in the year/scenario being evaluated to the emissions in the modeled 2023 or 2026 baseline scenario. Contributions from tags representing sources other than EGUs and non-EGUs are held constant at baseline levels for each of the regulatory alternative scenarios. For each control scenario analyzed, the scaled contributions from all sources were summed together to create a gridded surface of total modeled ozone. Finally, spatial fields of ozone were created based on "fusing" modeled data with measured concentrations at air quality monitoring locations. The process is described in a step-by-step manner below.

(1) The enhanced Voroni Neighbor Average (eVNA) technique was applied to ozone model predictions in conjunction measured data to create modeled/measured fused surfaces (i.e., spatial fields) of AS-MO3 for the 2016 base year.

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[3] Information on the emissions inventories used for the modeling described in *Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform*

[4] The air quality modeling performed to support the analyses in this proposed RIA can be found in the *Air Quality Modeling Technical Support Document Federal Implementation Plan Addressing Regional Ozone Transport for het 2015 Ozone National Ambient Air Quality Standards Proposed Rulemaking*

[5] Contributions from EGUs and non-EGUs were modeled using baseline emissions for 2026. The resulting contributions were used to construct spatial fields in both 2023 and 2026.

(2) The model-predicted spatial fields (i.e., not the eVNA fields) of AS-MO3 in 2016 were paired with the corresponding model-predicted spatial fields in 2023 and 2026 to calculate the ratio of AS-MO3 between 2016 and each of these future year baselines in each model grid cell.

(3) The ratios for 2016/2023 and 2016/2026 were applied to the eVNA spatial field for 2016 created in step (1) to produce eVNA spatial fields for the 2023 and 2026 baseline scenarios.

(4) The EGU and non-EGU ozone season NO_X emissions for the alternative control scenarios in 2023 and 2026 and the corresponding 2023 and 2026 baseline NO_X emissions were used to calculate the ratio of control scenario emissions to 2023 and 2026 baseline emissions for each EGU and non-EGU state contribution tag (i.e., an ozone-season scaling factor for each tag).

(5) The source apportionment modeling provided separate ozone contributions for ozone formed in VOC-limited chemical regimes (O_3V) and ozone formed in NO_X-limited chemical regimes (O_3N).[6] The EGU and non-EGU NOx emissions for the control scenarios and the corresponding baseline emissions are used to calculate the ratio of the control scenario emissions to the baseline emission to create scaling ratios for EGUs and for non-EGUs. The emissions scaling ratios are multiplied by the corresponding O_3N gridded contributions to MDA8 concentrations. This step results in adjusted gridded MDA8 contributions due to NO_X changes for individual state EGU and non-EGU tags that reflects the emissions in a specific control scenario.

(6) For MDA8, the adjusted contributions for each EGU and non-EGU state tag from step (3) are added together to produce adjusted EGU and non-EGU tag totals. Since there are no predicted changes in VOC emissions in the control scenarios, the O_3V contributions remain unchanged. The contributions from the unaltered O_3V tags are added to the summed adjusted O_3N EGU and non-EGU tags.

[6] Information on the treatment of ozone contributions under NOx-limited and VOC-limited chemical regimes in the CAMx APCA source apportionment technique can be found in the CAMx v7.10 User's Guide (Ramboll, 2021).

(7) The EGU MDA8 contributions from step (6) are then combined with the contributions to MDA8 from all other sources. This step results in MDA8 concentrations for each of the control scenario in each model grid cell, nationwide for each day in the ozone season.

(8) We then average the daily MDA8 concentrations across all days in the period April through September.

(9) The seasonal mean concentrations from step (8) are divided by the corresponding seasonal mean concentrations from the 2016 base year air quality model run. This step provides a Relative Response Factor (i.e., RRF) between the base period and control scenario for MDA8 ozone in each model grid cell.

(10) The RRFs for the AS-MO3 metric from step (9) are then multiplied by the corresponding eVNA 2016 base year from step (1) to produce the eVNA AS-MO3 spatial fields for the control scenario that are input to BenMAP-CE.

3.3 Generation of Spatial Fields for the Proposed FIP for the 2015 Ozone NAAQS

In this section we describe how we generated spatial fields of seasonal ozone concentrations associated with the regulatory control alternatives (i.e., the proposed policy case and the less stringent and more stringent alternatives). The data for creating spatial fields for each scenario include (1) EGU and non-EGU ozone season NOx emissions for the 2023 and 2026 baseline scenarios and the regulatory control alternatives, (2) spatial fields of AS-MO3 for the 2023 and 2026 baseline scenarios, and (3) the spatial field of mean AS-MO3 ozone contributions for the hours that correspond to the time periods of MDA8 concentrations.

To calculate ozone-related benefits in 2023 and 2026 we used the ozone season EGU and non-EGU NOx emissions for the 2023 and 2026 baseline scenarios along with emissions for the regulatory control alternatives. These emissions were applied using the method described in the previous section to produce spatial fields of the AS-MO3 for the three regulatory cases for EGU controls in 2023 and the EGU-only, non-EGU-only, and EGU plus non-EGU regulatory cases analyzed in this RIA.

3.4 Spatial Distribution of Air Quality Impacts

The spatial fields of baseline AS-MO3 in 2023 and 2026 are presented in Figure 3-2 and Figure 3-3, respectively. 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 is typically not highest at the location of the precursor emissions but rather peaks at some distance downwind of those emissions sources. The spatial gradients of ozone depend on a multitude of factors including the spatial patterns of NOx 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-MO3 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 MDA8 ozone concentrations on specific high ozone episode days.

The distribution of AS-MO3 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-MO3 concentrations are in the inter-mountain 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.

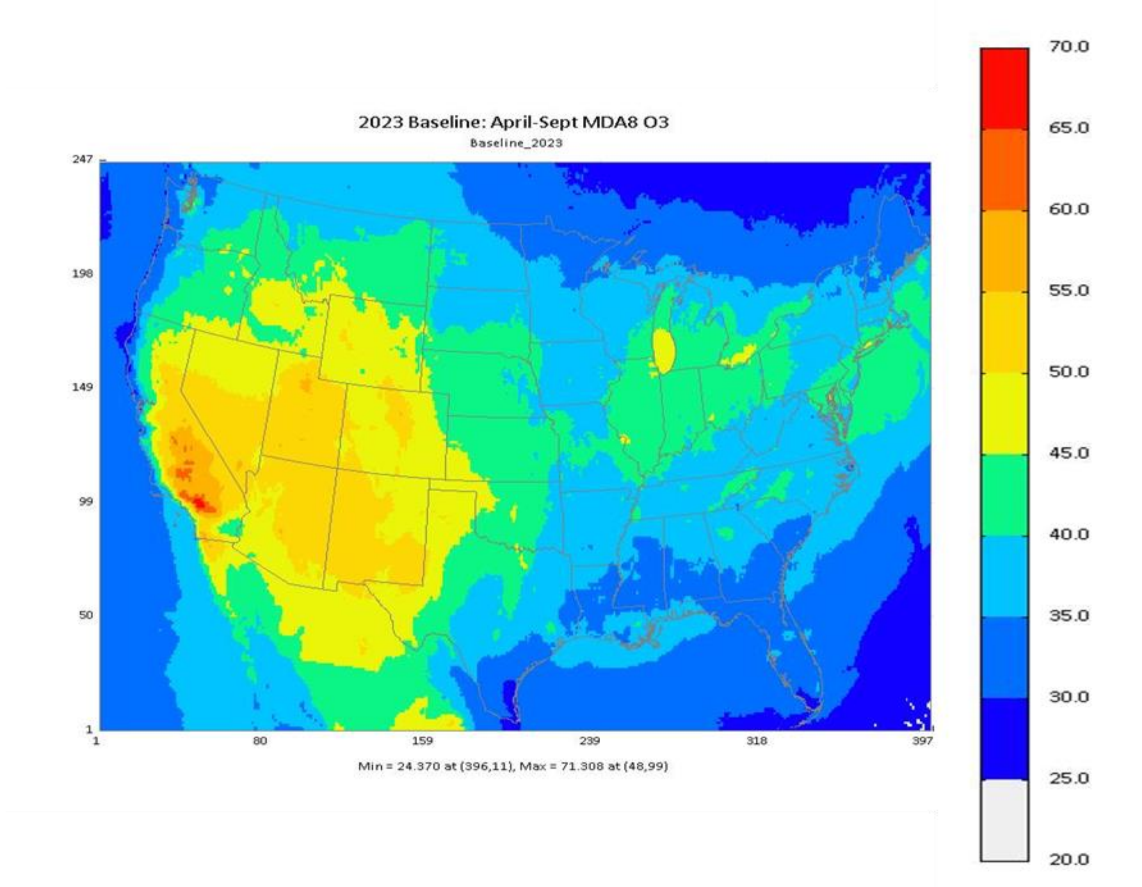

Figure 3-2. Baseline AS-MO3 concentration in 2023 (ppb).

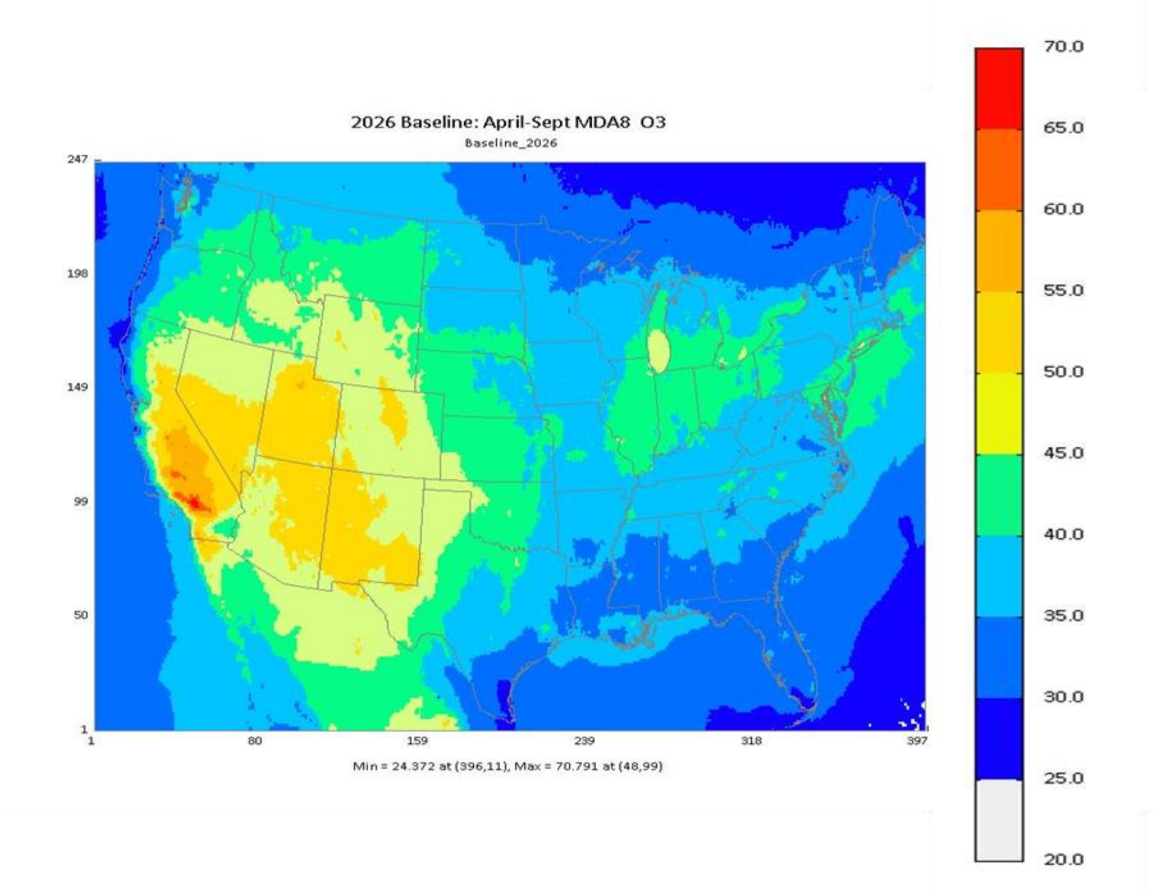

Figure 3-3. Baseline AS-MO3 concentration in 2026 (ppb).

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. Note that the impacts of the control alternatives in 2026 are much larger than the impacts of the control alternatives in 2023. In this regard, the scale used to display the impacts is different for the 2023 cases compared to the 2026 cases. Note that the scale ranges from 0 to 0.1 ppb on the plots for 2023, whereas the scale ranges from 0 to 1.0 ppb on the plots for 2026 because the impacts in 2026 are much greater than in 2023.

The data shown in Figures 3-4 through 3-15 are calculated as the baseline minus the regulatory control alternative concentrations (i.e., positive values indicate reductions in pollutant concentrations). The spatial patterns of the impacts of emissions reductions are a result of (1) the spatial distribution of EGU and non-EGU sources with changes in emissions between the baseline and the individual regulatory control alternatives and (2) the physical or chemical processing that the model simulates in the atmosphere.

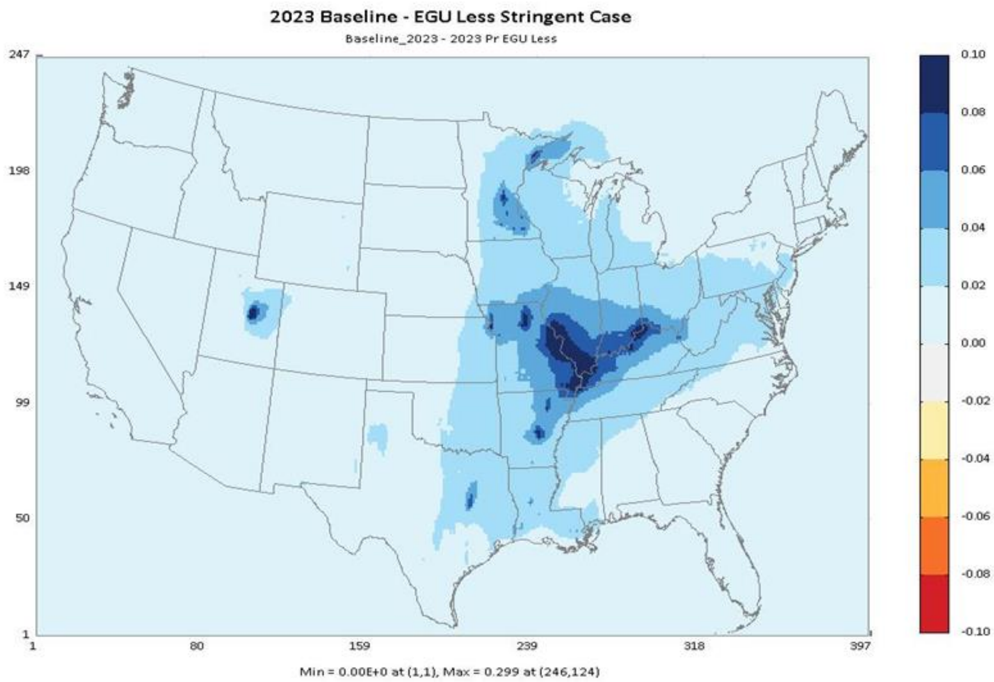

Figure 3-4. Reduction in AS-MO3 (ppb):
2023 baseline – less stringent EGU-only alternative (scale: + 0.1 ppb).

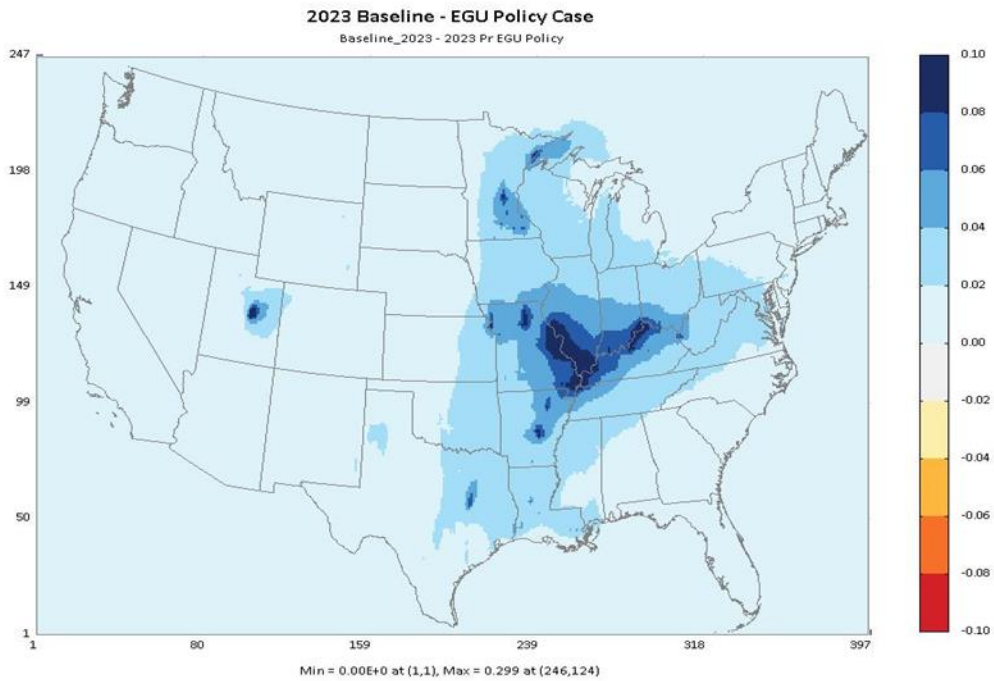

Figure 3-5. Reduction in AS-MO3 (ppb): 2023 baseline – EGU-only proposed rule alternative (scale: + 0.1 ppb).

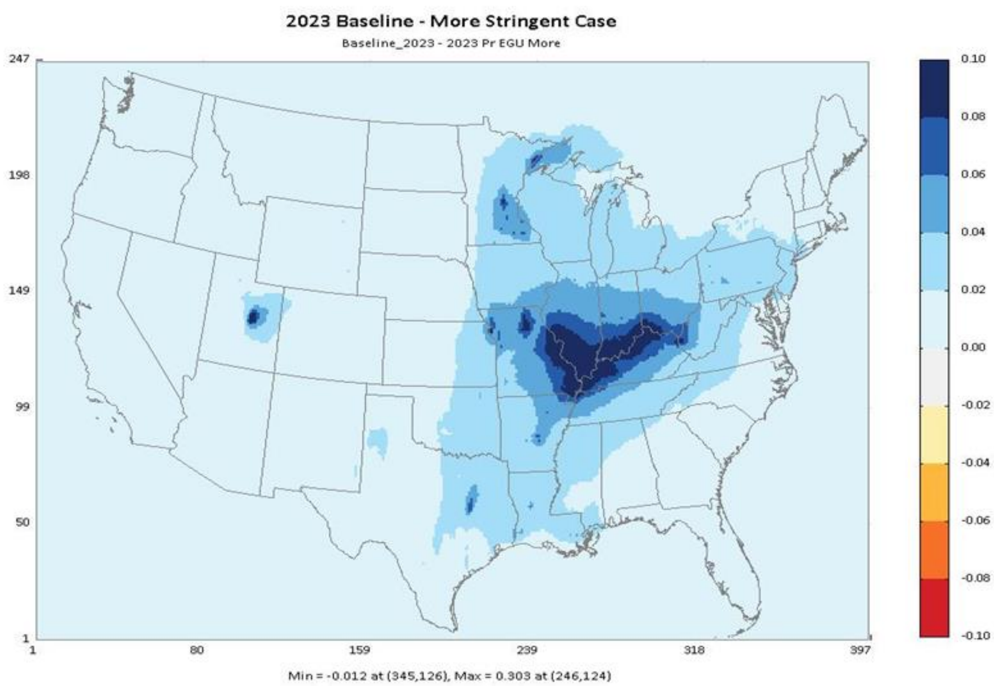

Figure 3-6. Reduction in AS-MO3 (ppb):
2023 baseline – more stringent EGU-only alternative (scale: + 0.1 ppb).

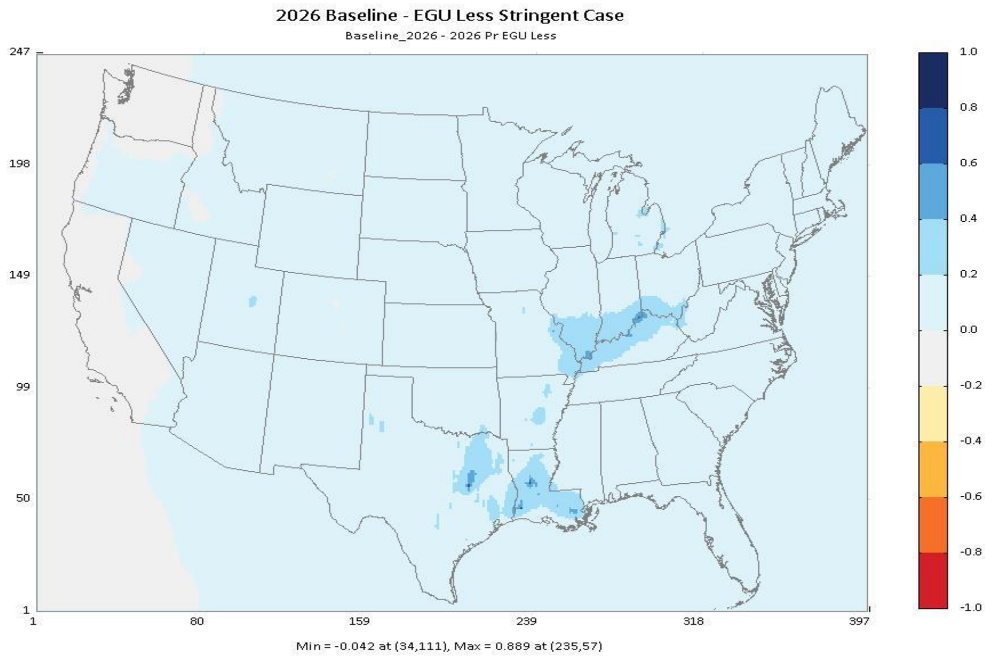

Figure 3-7. Reduction in AS-MO3 (ppb):
2026 baseline – less stringent EGU-only alternative (scale: + 1 ppb).

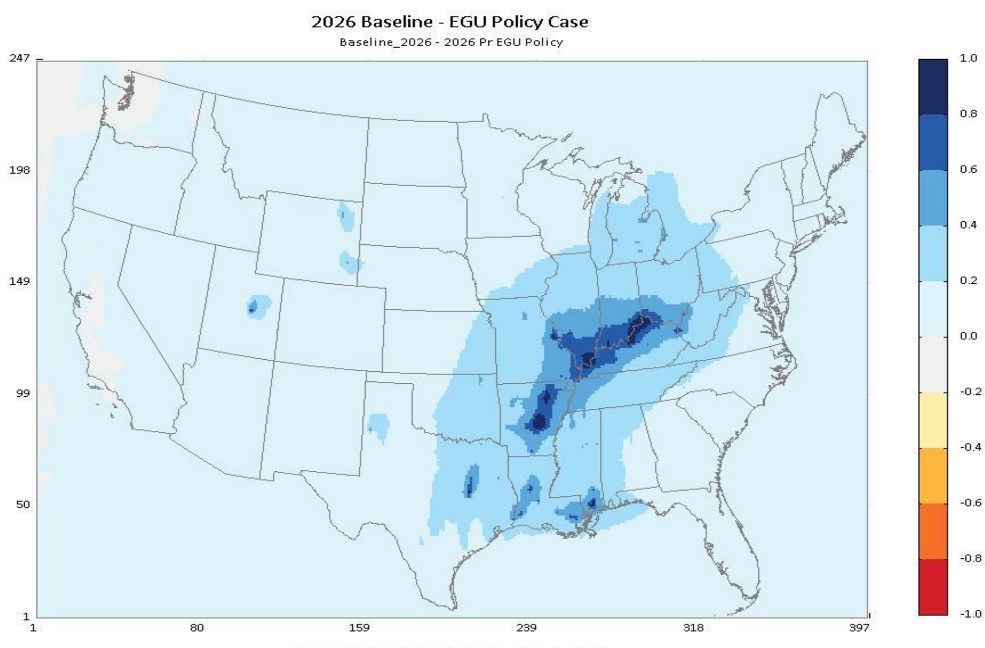

Figure 3-8. Reduction in AS-MO3 (ppb):
2026 baseline – EGU-only proposed rule alternative (scale: + 1 ppb).

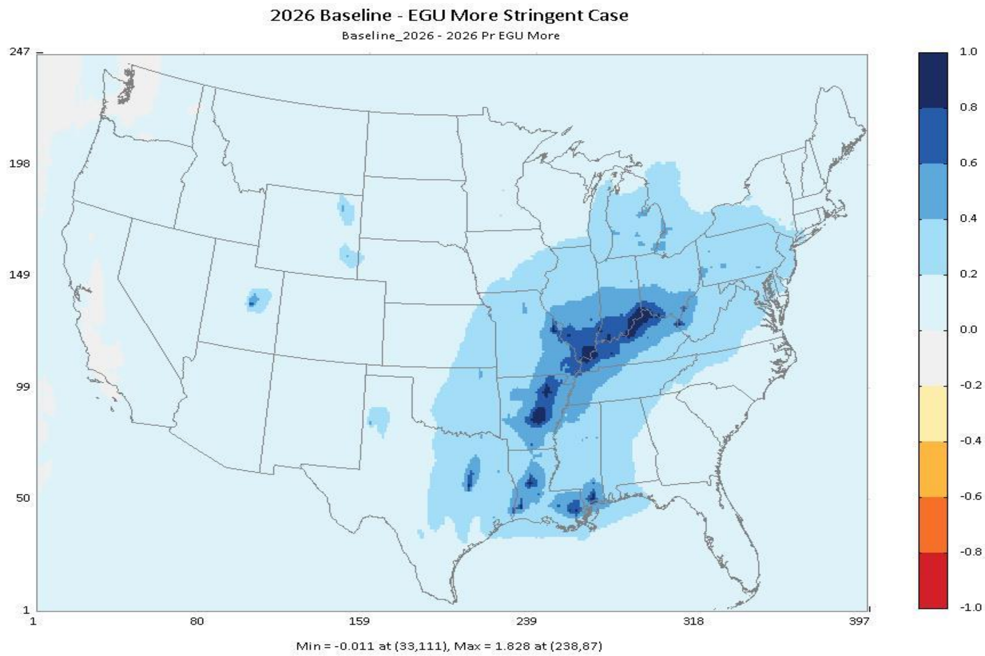

Figure 3-9. Reduction in AS-MO3 (ppb):
2026 baseline – more stringent EGU-only alternative (scale: + 1 ppb).

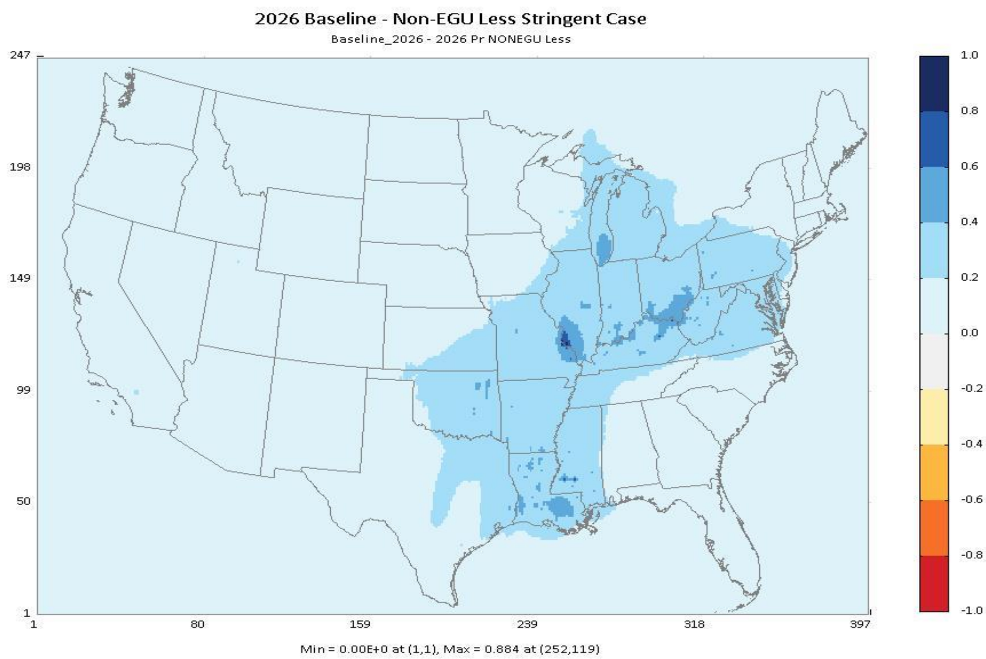

Figure 3-10. Reduction in AS-MO3 (ppb):
2026 baseline – less stringent non-EGU-only alternative (scale: + 1 ppb).

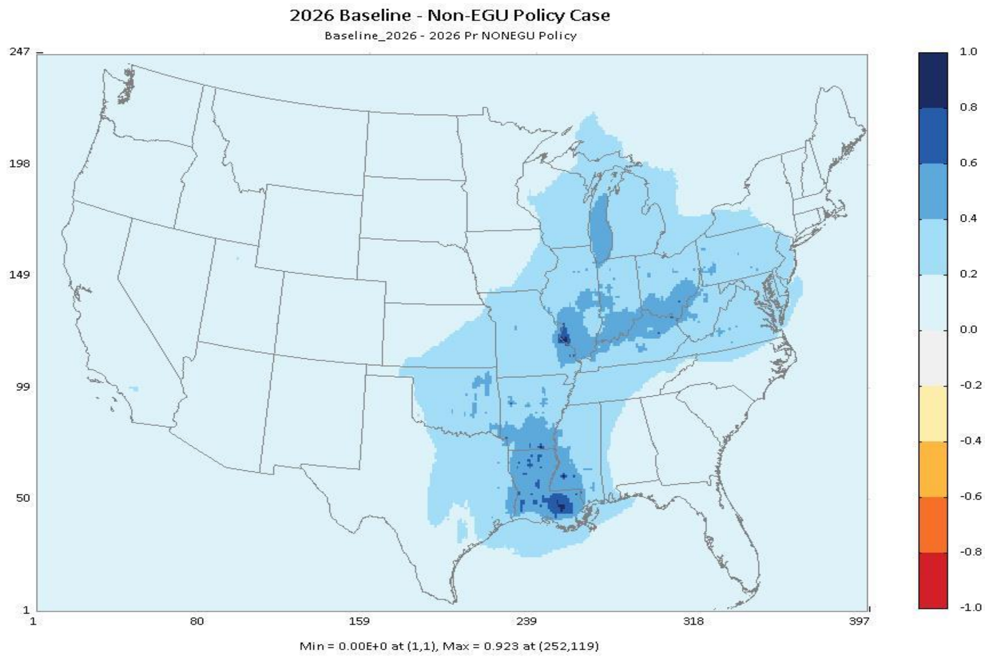

Figure 3-11. Reduction in AS-MO3 (ppb):
2026 baseline – non-EGU-only proposed rule alternative (scale: + 1 ppb).

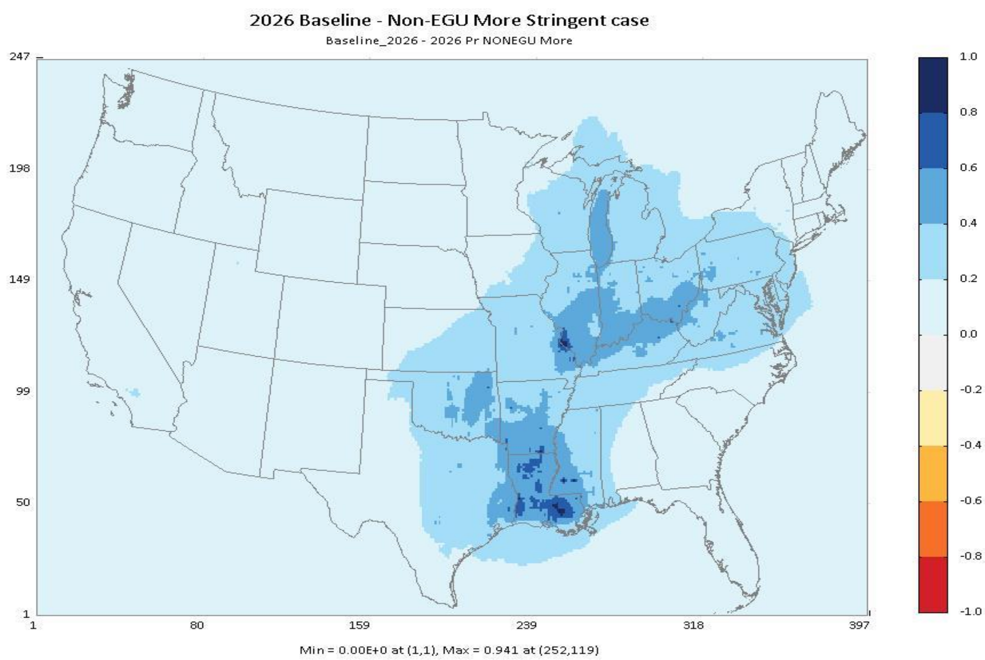

Figure 3-12. Reduction in AS-MO3 (ppb):
2026 baseline – more stringent non-EGU-only alternative (scale: + 1 ppb).

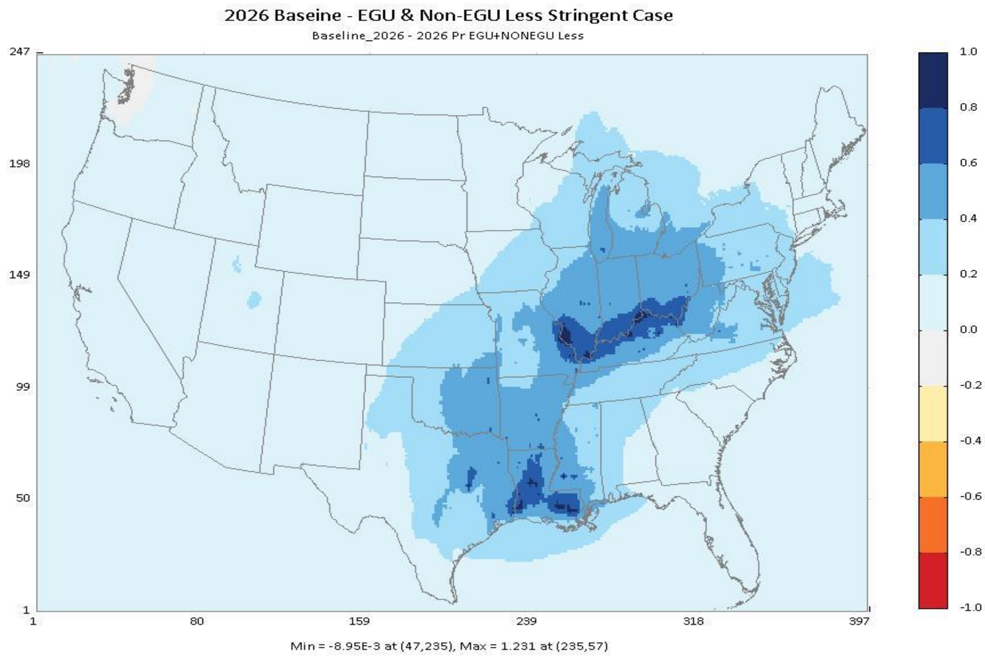

Figure 3-13. Reduction in AS-MO3 (ppb):
2026 baseline – less stringent EGU+non-EGU alternative (scale: + 1 ppb).

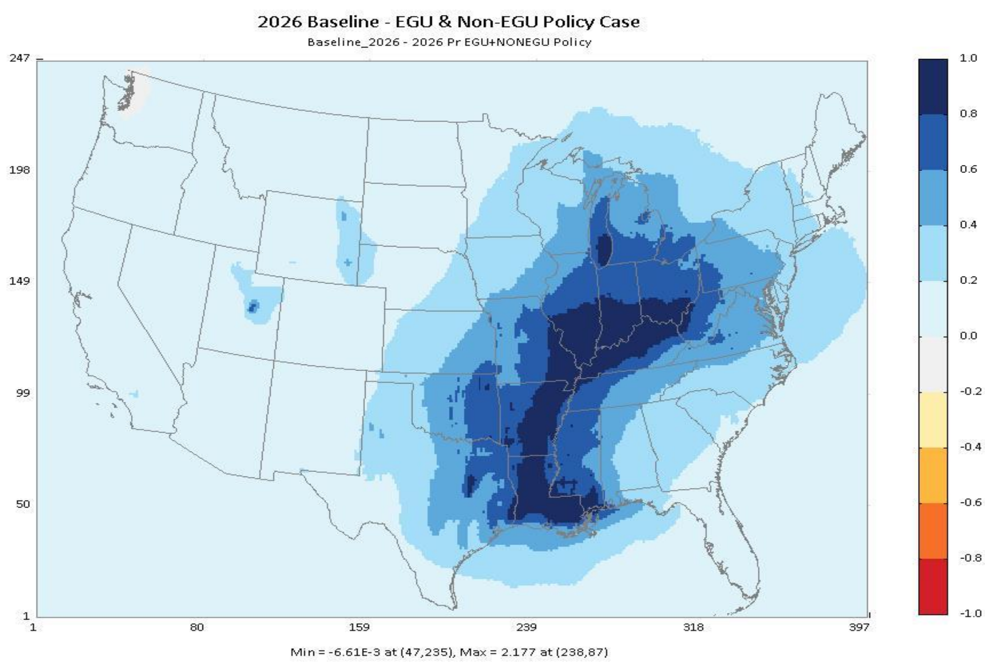

Figure 3-14. Reduction in AS-MO3 (ppb):
2026 baseline – EGU+non-EGU proposed rule alternative (scale: + 1 ppb).

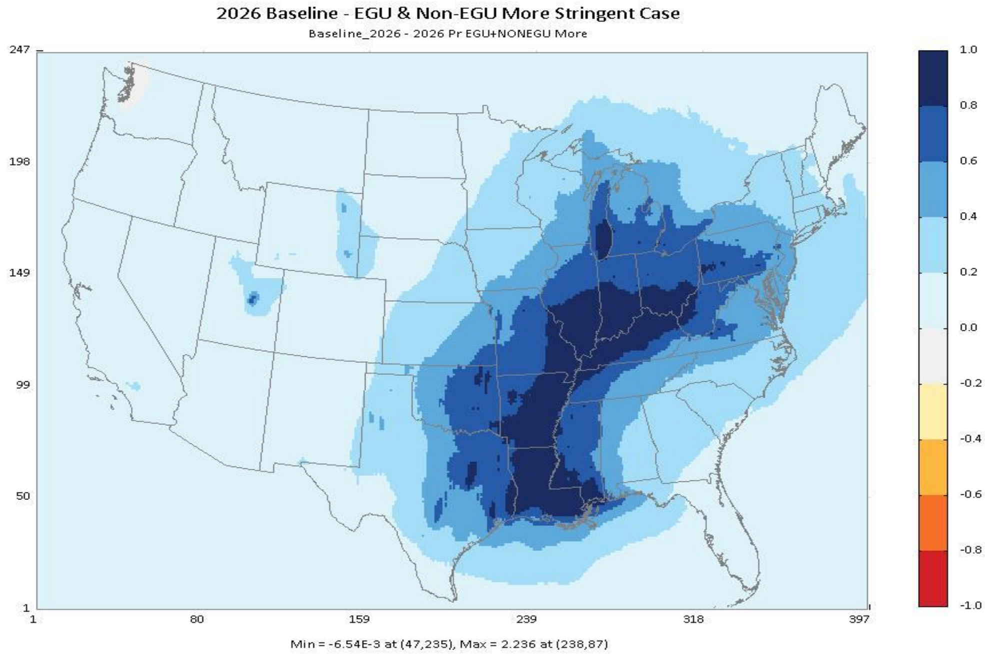

Figure 3-15. Reduction in AS-MO3 (ppb):
2026 baseline – more stringent EGU+non-EGU alternative (scale: + 1 ppb).

3.5 Uncertainties and Limitations

One limitation of the scaling methodology for creating ozone surfaces associated with the baseline and regulatory 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 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 alternatives are relatively small compared to modeled 2023 emissions that form the basis of the source apportionment approach described in Appendix 3A. 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 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 (EPA, 2022).

The regulatory 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 alternatives, which introduces uncertainty in the benefits and costs of the alternatives. To the extent the proposed FIP for the 2015 ozone NAAQS will decrease NO_X 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 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 financial and economic benefits from reduced compliance costs, 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 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 alternatives.

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APPENDIX 3A: METHODOLOGY FOR DEVELOPING AIR QUALITY SURFACES

In this appendix we describe the methodology that was used to prepare the air quality surfaces that could inform the calculation of health benefits of the proposed Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (FIP for the 2015 ozone NAAQS). As described in chapter 3, the foundational data include (1) spatial fields of April through September MDA8 concentrations for the 2023 and 2026 baselines, (2) ozone season EGU and non-EGU emissions for the baseline scenarios and each of the regulatory control alternatives in 2023 and 2026, and (3) the 2026 EGU and non-EGU April through September MDA8 ozone contribution data.

3A.1 Applying Source Apportionment Contributions to Create Air Quality Fields

Air quality surfaces for the 2023 and 2026 baseline and regulatory control alternatives were created by scaling the EGU and non-EGU sector tagged contributions from the 2026 modeling based on relative changes in EGU and/or non-EGU emissions associated with each tagged category between the modeled scenario and the 2023 and 2026 baseline and regulatory control alternatives. Below, we provide equations used to apply these scaling ratios.

3A.1.1 Creating Fused Fields Based on Observations and Model Surfaces

In this section we describe steps taken to create ozone gridded surfaces that combine modeled and monitor data to estimate ozone concentrations in 2023 and 2026 that serve as the starting point for estimating ozone under the baseline and regulatory control in 2023 and 2026 respectively. Ozone MDA8 concentrations were processed into April through September average surfaces which combine observed values with model predictions using the enhanced Veronoi Neighbor Average (eVNA) method (Gold et al., 1997; US EPA, 2007; Ding et al., 2015). First, we create a 2016 eVNA surface for MDA8 ozone using EPA's software package, Software for the Modeled Attainment Test – Community Edition (SMAT-CE)[1] . SMAT-CE calculates April through September MDA8 average values (i.e., AS-MO3) at each monitoring site with available

[1] Software download and documentation available at https://www.epa.gov/scram/photochemical-modeling-tools. Software has been previously documented both in the user's guide for the predecessor software (Abt, 2014) and in EPA's modeling guidance document (U.S. EPA, 2014b).

measured data. For this calculation we used 3 years of monitoring data (2015-2017)[2]. SMAT-CE then creates an interpolated field of the AS-MO3 using inverse distance weighting resulting in a separate 3-year average interpolated observed field for this metric. The interpolated observed fields are then adjusted to match the spatial gradients from the 2016 modeled data. These two steps can be calculated using Equation (1):

$$eVNA_{g,2016} = \sum Weight_x Monitor_{x,2015-2017} \frac{Model_{g,2016}}{Model_{x,2016}} \quad \text{(Eq-1)}$$

Where:

- $eVNA_{g,2016}$ is the gradient adjusted AS-MO3 eVNA value at grid-cell, g in 2016
- $Weight_x$ is the inverse distance weight for monitor x at the location of grid-cell, g;
- $Monitor_{x,2015-2017}$ is the 3-year (2015-2017) AS-MO3, at monitor, x;
- $Model_{g,2016}$ is the 2016 modeled AS-MO3 concentrations at grid cell, g; and
- $Model_{x,2016}$ is the 2016 modeled AS-MO3 concentration at the location of monitor, x.

The 2016 eVNA field serves as the starting point for future-year eVNA surfaces for the 2023 and 2026 modeled cases. To create a gridded 2023 and 2026 eVNA surfaces, we take the ratio of the modeled future year[3] AS-MO3 concentration to the modeled 2016 AS-MO3 concentration in each grid cell then and multiply that ratio by the corresponding 2016 eVNA AS-MO3 concentration in that grid cell (Equation 2).

- $eVNA_{g,future} = \left(eVNA_{g,2016}\right) \times \frac{Model_{g,future}}{Model_{g,2016}}$ (Eq-2)

[2] Three years of ambient data is used to provide a more representative picture of air pollution concentrations.
[3] In this analysis the "future year" represents either the 2023 or 2026 modeled case.

3A.1.2 Scaling Ratio Applied to Source Apportionment Tags

The relative contributions from each source in the 2026 source apportionment modeling is applied to adjust the 2023 and 2026 eVNA surfaces to estimate AS-MO3 associated with the 2023 and 2026 baseline and regulatory control scenarios. Source apportionment contributions from EGU and NONEGU source are scaled to represent emissions in the baseline and regulatory control scenarios for each year. Scaling ratios for ozone formed in NO_X-limited regimes[4] ("O3N") were based on relative changes in ozone season (May-September) NO_X emissions. Scaling ratios for ozone formed in VOC-limited regimes ("O3V") were set to 1 in all cases because no changes in VOC emissions were simulated as part of this rule. The scaling ratios were determined based on emissions provided for each scenario. Relative contributions from all other sources remain the same as the relative contributions from the 2026 source apportionment modeling. The final AS-MO3 for each scenario is calculated using equation (3):

$$\begin{aligned} Ozone_{g,i,y} = eVNA_{g,y} \\ \times \Bigg(\frac{C_{g,BC}}{C_{g,Tot}} + \frac{C_{g,int}}{C_{g,Tot}} + \frac{C_{g,bio}}{C_{g,Tot}} + \frac{C_{g,fires}}{C_{g,Tot}} + \frac{C_{g,USanthro}}{C_{g,Tot}} \\ + \sum_{t=1}^{T} \frac{C_{EGUVOC,g,t}}{C_{g,Tot}} + \sum_{t=1}^{T} \frac{C_{EGUNOx,g,t}\, S_{e,t,i,y}}{C_{g,Tot}} + \sum_{t=1}^{T} \frac{C_{NONEGUVOC,g,t}}{C_{g,Tot}} \\ + \sum_{t=1}^{T} \frac{C_{NONEGUNOx,g,t}\, S_{e,t,i,y}}{C_{g,Tot}} \Bigg) \end{aligned} \qquad \text{(Eq-3)}$$

where:

- $Ozone_{g,i,y}$ is the estimated fused model-obs AS-MO3 for grid-cell, "g", scenario, "i"[5], and year, "y"[6];
- $eVNA_{g,y}$ is the eVNA future year AS-MO3 for grid-cell "g" and year "y" calculated using Eq-13.

[4] The CAMx model internally determines whether the ozone formation regime is NO_X-limited or VOC-limited depending on predicted ratios of indicator chemical species.
[5] Scenario "i" can represent either baseline or regulatory control scenario.
[6] Year "y" can represent either 2023 or 2026.

- $C_{g,Tot}$ is the total modeled AS-MO3 for grid-cell "g" from all source in the 2026 source apportionment modeling

- $C_{g,BC}$ is the 2026 AS-MO3 modeled contribution from the modeled boundary inflow;

- $C_{,g,int}$ is the 2026 AS-MO3 modeled contribution from international emissions within the modeling domain;

- $C_{g,bio}$ is the 2026 AS-MO3 modeled contribution from biogenic emissions;

- $C_{g,fires}$ is the 2026 AS-MO3 modeled contribution from fires;

- $C_{g,USanthro}$ is the total 2026 AS-MO3 modeled contribution from U.S. anthropogenic sources other than EGUs and non-EGUs;

- $C_{EGUVOC,g,t}$ is the 2026 AS-MO3 modeled contribution from EGU emissions of VOCs from state, "t";

- $C_{EGUNOx,g,d,t}$ is the 2026 AS-MO3 modeled contribution from EGU emissions of NO_X from state, "t";

- $C_{NONEGUVOC,g,d,t}$ is the 2026 AS-MO3 modeled contribution from EGU emissions of VOCs from state, "t";

- $C_{NONEGUNOx,g,d,t}$ is the 2026 AS-MO3 modeled contribution from EGU emissions of NO_X from state, "t"; and

- $S_{e,t,i,y}$ is the EGU NO_X scaling ratio for state, "t", scenario "i", and year, "y".

- $S_{n,t,i,y}$ is the non-EGU NO_X scaling ratio for state, "t", scenario "i", and year, "y".

3A.2 References

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APPENDIX 3B: OZONE IMPACTS OF ALTERNATIVE CONTROL CASES

In this appendix we provide the estimated impacts on projected 2023 and 2026 ozone design values that are expected to result from the EGU and non-EGU control alternatives analyzed in this RIA. As described in Chapter 4, the alternative scenarios include the proposed rule control case along with scenarios that reflect less stringent and more stringent controls on EGU and non-EGUs. Because of timing constraints, we were not able to perform full-scale photochemical air quality modeling for these cases to quantify the ozone impacts. Rather, we applied the Air Quality Assessment Tool (AQAT) that was used to inform the air quality analyses in Step 3 of the 4-step transport framework as the method for estimating the impacts of the three control cases.[1] In the application of AQAT for the analysis presented here, we started with the model-projected average and maximum design values and state-to-receptor air quality contributions for the 2023 and 2026 base case scenarios at individual receptors along with the emissions changes in 2023 and in 2026 that are expected to result from the implementation of emissions controls for the alternative cases analyzed in this RIA. Using the emissions data, we calculated emissions reduction fractions compared to the 2026 base case and then we applied these fractions to the 2026 state-to-receptor contribution data to modulate the contributions at each receptor. Next, the change in contributions were adjusted using "calibration factors" to reflect the effects of the nonlinear response of ozone to changes in NOx emissions. The "calibrated" change in contributions were then subtracted from the corresponding 2023 or 2026 base case contributions to reflect how the base case contributions to that receptor are expected to change as a result of emissions reductions. The adjusted state-to-receptor contributions are then summed to estimate design values for each control case. Finally, the control case design values are compared to the corresponding base case values to determine the "ppb" impacts at individual receptors. In the application of AQAT to estimate ozone impacts at individual receptors, we included the combined effects of emissions reductions in each linked state at each receptor. As part of this approach, the impacts at an individual receptor reflect the effects of emissions reductions in all upwind states, not just those upwind states linked to that particular receptor. In

[1] See the Ozone Policy Analysis Proposed Rule TSD which can be found in the docket for this proposed rule for details on the construction of the ozone AQAT.

addition, the ozone reductions at a receptor also reflect the impact from emissions within that receptor's state, if that state is linked to a receptor in another state.[2]

3B.1 Analysis of Emissions Reductions

In Tables 3B-1 and 3B-2, respectively, we provide the ozone season state total NOx emissions (tons) for the 2023 and 2026 base case scenarios along with the changes in emissions by state expressed in terms of tons reduced (i.e., emissions delta) and percent reduction from the corresponding base case.[3] Details on the factors which drive these emissions changes can be found in Chapter 4. In 2023 the magnitude of emissions reductions expected from the proposed case and the less stringent case are very similar in most states. In the more stringent case, emissions reductions are notably greater than the proposed case in Illinois, Kentucky, and Pennsylvania. The controls included in the three alternative cases are expected to reduce state total ozone season NOx emissions from 1 to 2 percent in Kentucky, Minnesota, Missouri, and Utah with lesser percent reductions in other state covered by this proposed rule. In 2026, the magnitude and geographic extent of emissions reductions are both much greater than in 2023 due to the additional control opportunities by 2026 for reducing emissions from EGUs and the availability of controls for reducing emissions from non-EGUs. In contrast to 2023, the emission reductions from the proposal case and more stringent case are similar, but notably exceed the amount of reduction in the less stringent case. Under the proposal and more stringent cases, 21 states are expected to see reductions in total NOx emissions of greater than 5 percent. Moreover, in the 2026 proposal case, NOx reductions of 10 percent or more are expected in Arkansas, Kentucky, Louisiana, Mississippi, and Wyoming.

[2] For example, the impacts on ozone at receptors in Texas reflect the effects of emissions reductions in Texas combined with emissions reductions in all states that are upwind of Texas.

[3] The explanation for the change in emissions between each alternative emissions control scenario and the corresponding base case is provided in Chapter 4.

Table 3B-1. Total anthropogenic 2023 base case NOx emissions, emissions deltas, and percent reductions by state for each alternative control case.[4]

State	2023 Base NOx	Emission Delta Proposed Rule	Emission Delta Less Stringent	Emission Delta More Stringent	Percent Reduction Proposed Rule	Percent Reduction Less Stringent	Percent Reduction More Stringent
Alabama	66,312	0	0	3	0.0%	0.0%	0.0%
Arizona	38,612	0	0	0	0.0%	0.0%	0.0%
Arkansas	43,202	206	207	111	0.5%	0.5%	0.3%
California	139,593	3	3	3	0.0%	0.0%	0.0%
Colorado	53,121	0	0	0	0.0%	0.0%	0.0%
Connecticut	11,820	0	0	-2	0.0%	0.0%	0.0%
Delaware	6,878	5	7	5	0.1%	0.1%	0.1%
District of Columbia	1,390	0	0	0	0.0%	0.0%	0.0%
Florida	100,080	5	5	5	0.0%	0.0%	0.0%
Georgia	67,589	-2	-2	-2	0.0%	0.0%	0.0%
Idaho	19,622	0	0	0	0.0%	0.0%	0.0%
Illinois	97,086	24	25	155	0.0%	0.0%	0.2%
Indiana	73,491	241	239	270	0.3%	0.3%	0.4%
Iowa	46,836	-12	-16	2	0.0%	0.0%	0.0%
Kansas	62,587	15	15	32	0.0%	0.0%	0.1%
Kentucky	54,506	635	588	1,034	1.2%	1.1%	1.9%
Louisiana	103,038	245	245	231	0.2%	0.2%	0.2%
Maine	14,097	-4	-2	-4	0.0%	0.0%	0.0%
Maryland	25,735	4	4	-3	0.0%	0.0%	0.0%
Massachusetts	28,105	-1	-1	3	0.0%	0.0%	0.0%
Michigan	80,760	-16	-15	6	0.0%	0.0%	0.0%
Minnesota	62,656	971	972	970	1.5%	1.6%	1.5%
Mississippi	34,435	37	37	37	0.1%	0.1%	0.1%
Missouri	76,251	1,448	1,447	1,445	1.9%	1.9%	1.9%
Montana	28,408	0	0	0	0.0%	0.0%	0.0%
Nebraska	43,826	-11	-11	-17	0.0%	0.0%	0.0%
Nevada	18,286	3	4	4	0.0%	0.0%	0.0%
New Hampshire	7,287	-1	-1	-1	0.0%	0.0%	0.0%
New Jersey	34,476	53	51	51	0.2%	0.1%	0.1%
New Mexico	65,186	48	48	44	0.1%	0.1%	0.1%
New York	69,960	68	68	92	0.1%	0.1%	0.1%
North Carolina	58,908	3	2	0	0.0%	0.0%	0.0%

[4] Note that positive values indicate reductions and negative values indicate increases in emissions.

State	2023 Base NOx	Emission Delta Proposed Rule	Emission Delta Less Stringent	Emission Delta More Stringent	Percent Reduction Proposed Rule	Percent Reduction Less Stringent	Percent Reduction More Stringent
North Dakota	59,167	12	12	12	0.0%	0.0%	0.0%
Ohio	85,480	62	45	97	0.1%	0.1%	0.1%
Oklahoma	90,114	51	51	58	0.1%	0.1%	0.1%
Oregon	33,155	0	0	0	0.0%	0.0%	0.0%
Pennsylvania	107,022	58	117	231	0.1%	0.1%	0.2%
Rhode Island	4,559	0	0	1	0.0%	0.0%	0.0%
South Carolina	43,650	0	0	-5	0.0%	0.0%	0.0%
South Dakota	12,972	0	0	0	0.0%	0.0%	0.0%
Tennessee	52,389	0	1	-4	0.0%	0.0%	0.0%
Texas	305,019	826	828	823	0.3%	0.3%	0.3%
Utah	35,692	688	688	689	1.9%	1.9%	1.9%
Vermont	3,853	0	0	0	0.0%	0.0%	0.0%
Virginia	50,590	57	56	-107	0.1%	0.1%	-0.2%
Washington	53,412	0	0	0	0.0%	0.0%	0.0%
West Virginia	43,830	0	0	0	0.0%	0.0%	0.0%
Wisconsin	45,503	-2	0	0	0.0%	0.0%	0.0%
Wyoming	34,211	99	99	98	0.3%	0.3%	0.3%
Tribal Data	4,057	0	0	0	0.0%	0.0%	0.0%

Table 3B-2. Total 2026 base case NOx emissions, emissions deltas, and percent reductions by state for each alternative control case.

State	2026 Base NOx	Emission Delta Proposed Rule	Emission Delta Less Stringent	Emission Delta More Stringent	Percent Reduction Proposed Rule	Percent Reduction Less Stringent	Percent Reduction More Stringent
Alabama	61,759	162	67	183	0%	0%	0%
Arizona	33,463	-2	-4	-24	0%	0%	0%
Arkansas	39,488	5,542	1,406	5,569	14%	4%	14%
California	133,629	1,636	1,500	1,746	1%	1%	1%
Colorado	49,825	-172	-239	-174	0%	0%	0%
Connecticut	10,887	0	1	9	0%	0%	0%
Delaware	6,447	5	5	6	0%	0%	0%
District of Columbia	1,302	0	0	0	0%	0%	0%
Florida	92,166	249	239	282	0%	0%	0%
Georgia	60,266	83	8	25	0%	0%	0%
Idaho	17,321	-3	-17	-3	0%	0%	0%

State	2026 Base NOx	Emission Delta Proposed Rule	Emission Delta Less Stringent	Emission Delta More Stringent	Percent Reduction Proposed Rule	Percent Reduction Less Stringent	Percent Reduction More Stringent
Illinois	91,069	4,135	3,157	4,184	5%	3%	5%
Indiana	68,291	6,047	3,554	6,173	9%	5%	9%
Iowa	41,049	77	-436	89	0%	-1%	0%
Kansas	59,107	402	389	403	1%	1%	1%
Kentucky	50,887	8,980	5,446	9,285	18%	11%	18%
Louisiana	100,361	11,402	8,225	13,012	11%	8%	13%
Maine	12,918	0	0	1	0%	0%	0%
Maryland	23,671	49	50	1	0%	0%	0%
Massachusetts	26,353	2	1	9	0%	0%	0%
Michigan	75,940	7,156	5,348	7,642	9%	7%	10%
Minnesota	55,972	1,747	726	1,858	3%	1%	3%
Mississippi	33,156	3,904	1,546	3,901	12%	5%	12%
Missouri	67,664	6,391	4,541	6,397	9%	7%	9%
Montana	25,642	-117	-118	-117	0%	0%	0%
Nebraska	38,322	-8	-17	-1	0%	0%	0%
Nevada	16,178	-8	-7	-9	0%	0%	0%
New Hampshire	6,719	1	1	2	0%	0%	0%
New Jersey	31,805	56	61	88	0%	0%	0%
New Mexico	62,210	93	86	91	0%	0%	0%
New York	65,642	800	515	1,545	1%	1%	2%
North Carolina	51,986	24	26	15	0%	0%	0%
North Dakota	55,294	746	1,300	729	1%	2%	1%
Ohio	78,681	4,006	3,429	4,289	5%	4%	5%
Oklahoma	83,411	4,223	3,574	4,500	5%	4%	5%
Oregon	29,345	11	8	12	0%	0%	0%
Pennsylvania	103,565	3,440	3,185	5,998	3%	3%	6%
Rhode Island	4,187	0	0	0	0%	0%	0%
South Carolina	38,939	94	91	128	0%	0%	0%
South Dakota	11,084	-8	-7	-8	0%	0%	0%
Tennessee	47,475	-33	-146	-15	0%	0%	0%
Texas	280,717	10,438	9,288	12,576	4%	3%	4%
Utah	29,762	2,774	1,681	2,801	9%	6%	9%
Vermont	3,378	0	0	0	0%	0%	0%
Virginia	46,496	1,680	1,537	1,724	4%	3%	4%
Washington	47,754	-27	-34	-27	0%	0%	0%

State	2026 Base NOx	Emission Delta Proposed Rule	Emission Delta Less Stringent	Emission Delta More Stringent	Percent Reduction Proposed Rule	Percent Reduction Less Stringent	Percent Reduction More Stringent
West Virginia	39,500	923	673	994	2%	2%	3%
Wisconsin	41,032	2,023	689	2,101	5%	2%	5%
Wyoming	32,928	3,336	1,299	3,338	10%	4%	10%
Tribal Data	4,052	0	0	0	0%	0%	0%

3B.2 Projected Impacts on Ozone Design Values

The expected impacts on ozone design value in 2023 and 2026 for the proposed, less stringent, and more stringent cases are provided in Tables 3B-3 and 3B-4 respectively. In 2023, there is little difference in the amount of ozone reduction across the three cases at individual receptors, which is consistent with the expected changes in NOx emissions, as shown in Table 3B-1, above. Overall, in 2023 the estimated ozone reductions from all three of the alternative cases are projected to be less than 0.1 ppb at most receptors. The exceptions are at certain receptors in Connecticut, Illinois, Texas, and Utah where impacts are between 0.1 and 0.2 ppb. In the 2026 the largest impacts in the proposed case are estimated at the two receptors in Texas (i.e., Brazoria County and Harris County, where the average reduction is 1.3 ppb. Elsewhere, the average reductions for the proposed case are on the order of 0.5 ppb at receptors in Connecticut, Illinois, and Wisconsin. The average reduction for the four receptors in Utah is approximately 0.3 ppb, while the average reduction at receptors in Colorado and California reductions are approximately 0.2 ppb. The data in Table 3B-4 indicates that the less stringent case provides approximately 0.1 to 0.3 ppb less ppb reduction (i.e., 30 to 40 percent less reduction), on average, compared to the proposed case at receptors in the East and in Colorado and Utah. The more stringent case does not appear to provide any notable additional ozone reductions compared to the proposed case in all receptor areas, except at receptors in Connecticut and Texas where the average reduction is 0.1 ppb and 0.2 ppb with the more stringent case, respectively.

Table 3B-3. Impact on projected 2023 design value of the emissions reductions in the proposed case, the less stringent case and more stringent case (ppb).

Site ID	State	County	Proposed Case	Less Stringent	More Stringent
40278011	AZ	Yuma	0.09	0.09	0.09
60070007	CA	Butte	0.03	0.03	0.03

Site ID	State	County	Proposed Case	Less Stringent	More Stringent
60090001	CA	Calaveras	0.09	0.09	0.09
60170010	CA	El Dorado	0.00	0.00	0.00
60170020	CA	El Dorado	0.09	0.09	0.09
60190007	CA	Fresno	0.04	0.04	0.04
60190011	CA	Fresno	0.03	0.03	0.03
60190242	CA	Fresno	0.04	0.04	0.04
60194001	CA	Fresno	0.07	0.07	0.07
60195001	CA	Fresno	0.03	0.03	0.03
60250005	CA	Imperial	0.02	0.02	0.02
60251003	CA	Imperial	0.06	0.06	0.06
60290007	CA	Kern	0.03	0.03	0.03
60290008	CA	Kern	0.02	0.02	0.02
60290011	CA	Kern	0.06	0.06	0.06
60290014	CA	Kern	0.03	0.03	0.03
60290232	CA	Kern	0.09	0.09	0.09
60292012	CA	Kern	0.03	0.03	0.03
60295002	CA	Kern	0.01	0.01	0.01
60311004	CA	Kings	0.06	0.06	0.06
60370002	CA	Los Angeles	0.09	0.09	0.09
60370016	CA	Los Angeles	0.02	0.02	0.02
60371103	CA	Los Angeles	0.06	0.06	0.06
60371201	CA	Los Angeles	0.10	0.10	0.10
60371602	CA	Los Angeles	0.04	0.04	0.04
60371701	CA	Los Angeles	0.01	0.01	0.01
60372005	CA	Los Angeles	0.02	0.02	0.02
60376012	CA	Los Angeles	0.00	0.00	0.00
60379033	CA	Los Angeles	0.01	0.01	0.01
60390004	CA	Madera	0.07	0.07	0.07
60392010	CA	Madera	0.02	0.02	0.02
60430003	CA	Mariposa	0.04	0.04	0.04
60470003	CA	Merced	0.06	0.06	0.06
60570005	CA	Nevada	0.05	0.05	0.05
60592022	CA	Orange	0.09	0.09	0.09
60595001	CA	Orange	0.06	0.06	0.06
60610003	CA	Placer	0.01	0.01	0.01
60610004	CA	Placer	0.02	0.02	0.02
60610006	CA	Placer	0.00	0.00	0.00
60650008	CA	Riverside	0.06	0.06	0.06
60650012	CA	Riverside	0.03	0.03	0.03

Site ID	State	County	Proposed Case	Less Stringent	More Stringent
60650016	CA	Riverside	0.00	0.00	0.00
60651016	CA	Riverside	0.02	0.02	0.02
60652002	CA	Riverside	0.02	0.02	0.02
60655001	CA	Riverside	0.05	0.05	0.05
60656001	CA	Riverside	0.05	0.05	0.05
60658001	CA	Riverside	0.00	0.00	0.00
60658005	CA	Riverside	0.03	0.03	0.03
60659001	CA	Riverside	0.04	0.04	0.04
60670002	CA	Sacramento	0.09	0.09	0.09
60670012	CA	Sacramento	0.00	0.00	0.00
60675003	CA	Sacramento	0.00	0.00	0.00
60710001	CA	San Bernardino	0.03	0.03	0.03
60710005	CA	San Bernardino	0.03	0.03	0.03
60710012	CA	San Bernardino	0.08	0.08	0.08
60710306	CA	San Bernardino	0.02	0.02	0.02
60711004	CA	San Bernardino	0.04	0.04	0.04
60711234	CA	San Bernardino	0.04	0.04	0.04
60712002	CA	San Bernardino	0.04	0.04	0.04
60714001	CA	San Bernardino	0.06	0.06	0.06
60714003	CA	San Bernardino	0.08	0.08	0.08
60719002	CA	San Bernardino	0.00	0.00	0.00
60719004	CA	San Bernardino	0.09	0.09	0.09
60731006	CA	San Diego	0.08	0.08	0.08
60773005	CA	San Joaquin	0.00	0.00	0.00
60990005	CA	Stanislaus	0.01	0.01	0.01
60990006	CA	Stanislaus	0.03	0.03	0.03
61070006	CA	Tulare	0.04	0.04	0.04
61070009	CA	Tulare	0.08	0.08	0.08
61072002	CA	Tulare	0.01	0.01	0.01
61072010	CA	Tulare	0.04	0.04	0.04
61090005	CA	Tuolumne	0.06	0.06	0.06
61112002	CA	Ventura	0.08	0.08	0.08
80350004	CO	Douglas	0.03	0.03	0.03
80590006	CO	Jefferson	0.11	0.11	0.11
80590011	CO	Jefferson	0.04	0.04	0.04
90010017	CT	Fairfield	0.09	0.09	0.10
90013007	CT	Fairfield	0.11	0.11	0.12
90019003	CT	Fairfield	0.10	0.10	0.11
90099002	CT	New Haven	0.12	0.12	0.13

Site ID	State	County	Proposed Case	Less Stringent	More Stringent
170310001	IL	Cook	0.04	0.04	0.04
170310032	IL	Cook	0.07	0.07	0.07
170310076	IL	Cook	0.03	0.03	0.03
170314201	IL	Cook	0.07	0.07	0.07
170317002	IL	Cook	0.11	0.10	0.11
320030075	NV	Clark	0.07	0.07	0.07
420170012	PA	Bucks	0.07	0.07	0.08
480391004	TX	Brazoria	0.15	0.15	0.15
481210034	TX	Denton	0.12	0.12	0.12
482010024	TX	Harris	0.14	0.14	0.14
482010055	TX	Harris	0.16	0.16	0.15
482011034	TX	Harris	0.16	0.16	0.16
482011035	TX	Harris	0.17	0.17	0.16
490110004	UT	Davis	0.07	0.07	0.07
490353006	UT	Salt Lake	0.13	0.13	0.13
490353013	UT	Salt Lake	0.12	0.12	0.12
490570002	UT	Weber	0.12	0.12	0.12
490571003	UT	Weber	0.12	0.12	0.12
550590019	WI	Kenosha	0.06	0.06	0.06
550590025	WI	Kenosha	0.04	0.04	0.04
551010020	WI	Racine	0.06	0.06	0.07

Table 3B-4. Impact on projected 2026 design value of the emissions reductions in the proposed case and the less stringent and more stringent cases (ppb).

Site ID	State	County	Proposed Case	Less Stringent	More Stringent
40278011	AZ	Yuma	0.07	0.07	0.07
60090001	CA	Calaveras	0.18	0.17	0.18
60170010	CA	El Dorado	0.18	0.17	0.19
60170020	CA	El Dorado	0.20	0.19	0.21
60190007	CA	Fresno	0.14	0.13	0.14
60190011	CA	Fresno	0.19	0.18	0.19
60190242	CA	Fresno	0.20	0.19	0.21
60194001	CA	Fresno	0.16	0.15	0.17
60195001	CA	Fresno	0.16	0.15	0.17
60250005	CA	Imperial	0.05	0.05	0.05
60251003	CA	Imperial	0.03	0.03	0.03
60290007	CA	Kern	0.23	0.21	0.24
60290008	CA	Kern	0.24	0.22	0.25

Site ID	State	County	Proposed Case	Less Stringent	More Stringent
60290011	CA	Kern	0.12	0.11	0.13
60290014	CA	Kern	0.22	0.20	0.23
60290232	CA	Kern	0.20	0.19	0.21
60292012	CA	Kern	0.26	0.25	0.27
60295002	CA	Kern	0.28	0.27	0.30
60311004	CA	Kings	0.16	0.15	0.17
60370002	CA	Los Angeles	0.26	0.24	0.27
60370016	CA	Los Angeles	0.25	0.24	0.27
60371201	CA	Los Angeles	0.19	0.17	0.19
60371602	CA	Los Angeles	0.12	0.11	0.13
60371701	CA	Los Angeles	0.27	0.25	0.28
60372005	CA	Los Angeles	0.18	0.17	0.19
60376012	CA	Los Angeles	0.17	0.15	0.18
60379033	CA	Los Angeles	0.21	0.20	0.22
60390004	CA	Madera	0.17	0.15	0.17
60392010	CA	Madera	0.18	0.17	0.19
60430003	CA	Mariposa	0.07	0.06	0.07
60470003	CA	Merced	0.18	0.17	0.19
60570005	CA	Nevada	0.16	0.14	0.17
60592022	CA	Orange	0.16	0.15	0.17
60595001	CA	Orange	0.15	0.14	0.16
60610003	CA	Placer	0.21	0.20	0.22
60610004	CA	Placer	0.19	0.18	0.20
60610006	CA	Placer	0.16	0.15	0.17
60650008	CA	Riverside	0.19	0.18	0.20
60650012	CA	Riverside	0.23	0.21	0.24
60650016	CA	Riverside	0.15	0.14	0.16
60651016	CA	Riverside	0.20	0.18	0.21
60652002	CA	Riverside	0.13	0.11	0.13
60655001	CA	Riverside	0.20	0.19	0.21
60656001	CA	Riverside	0.24	0.23	0.25
60658001	CA	Riverside	0.20	0.18	0.21
60658005	CA	Riverside	0.22	0.20	0.23
60659001	CA	Riverside	0.20	0.18	0.21
60670012	CA	Sacramento	0.21	0.20	0.22
60710001	CA	San Bernardino	0.14	0.13	0.15
60710005	CA	San Bernardino	0.25	0.23	0.27
60710012	CA	San Bernardino	0.24	0.23	0.25
60710306	CA	San Bernardino	0.17	0.15	0.18

Site ID	State	County	Proposed Case	Less Stringent	More Stringent
60711004	CA	San Bernardino	0.26	0.24	0.27
60711234	CA	San Bernardino	0.17	0.16	0.17
60712002	CA	San Bernardino	0.21	0.20	0.23
60714001	CA	San Bernardino	0.23	0.21	0.24
60714003	CA	San Bernardino	0.28	0.26	0.29
60719002	CA	San Bernardino	0.15	0.14	0.16
60719004	CA	San Bernardino	0.27	0.25	0.28
60731006	CA	San Diego	0.10	0.09	0.10
60773005	CA	San Joaquin	0.18	0.17	0.19
60990005	CA	Stanislaus	0.16	0.14	0.17
60990006	CA	Stanislaus	0.18	0.17	0.19
61070006	CA	Tulare	0.15	0.14	0.15
61070009	CA	Tulare	0.18	0.18	0.19
61072002	CA	Tulare	0.18	0.17	0.19
61072010	CA	Tulare	0.14	0.13	0.15
61090005	CA	Tuolumne	0.12	0.11	0.13
80350004	CO	Douglas	0.21	0.11	0.22
80590006	CO	Jefferson	0.17	0.09	0.17
80590011	CO	Jefferson	0.18	0.10	0.18
90010017	CT	Fairfield	0.48	0.39	0.60
90013007	CT	Fairfield	0.57	0.43	0.73
90019003	CT	Fairfield	0.46	0.35	0.58
90099002	CT	New Haven	0.54	0.41	0.67
170310001	IL	Cook	0.54	0.34	0.57
170310032	IL	Cook	0.32	0.19	0.35
170310076	IL	Cook	0.44	0.26	0.48
170314201	IL	Cook	0.49	0.32	0.52
170317002	IL	Cook	0.55	0.38	0.58
480391004	TX	Brazoria	1.37	0.97	1.55
482010024	TX	Harris	1.27	0.96	1.47
490110004	UT	Davis	0.38	0.27	0.38
490353006	UT	Salt Lake	0.31	0.21	0.32
490353013	UT	Salt Lake	0.40	0.27	0.41
490570002	UT	Weber	0.31	0.19	0.31
550590019	WI	Kenosha	0.51	0.32	0.54
550590025	WI	Kenosha	0.58	0.37	0.61
551010020	WI	Racine	0.59	0.38	0.62

3B.3 Alternative Control Case Projected Ozone Design Values

The projected average and maximum design values in 2023 at individual receptors are provided in Table 3B-5 for the proposed, less stringent and more stringent cases. Comparing the magnitude of the design values relative to the level of the NAAQS indicates that three of 101 receptors in 2023 are projected to change attainment status as a result of this proposed rule. Specifically, receptors in Clark County, Nevada, Butte County, California, and Riverside County California (Monitor ID: 060650008) are projected to switch from maintenance-only in the 2023 base case to attainment and the receptor in Harris County, Texas is projected to switch from nonattainment to maintenance-only under any of the alternative cases in 2023. In 2026, six of 89 receptors are projected to change attainment status as a result of the proposed rule. Specifically, receptors in Calaveras County, California, Brazoria County, Texas, and in Kenosha County, Wisconsin (Monitor ID: 550590025) are projected to switch from maintenance-only to attainment in 2026 and a receptor in Riverside County, California (Monitor ID: 060650016) is projected to switch from nonattainment to maintenance under any of the alternative cases. The receptor in Douglas County, Colorado and one of the receptors in Cook County, Illinois (Monitor ID: 170310076) are projected to switch from maintenance-only to attainment under the proposed and more stringent cases, but these receptors are projected to remain as maintenance-only in the less stringent case.

Table 3B-5. Projected average and maximum design values for the 2023 base case, the proposed case, less stringent case, and more stringent case (ppb).

Site ID	State	County	2023 Avg	2023 Max	Proposed Avg	Proposed Max	Less Stringent Avg	Less Stringent Max	More Stringent Avg	More Stringent Max
40278011	AZ	Yuma	70.5	72.2	70.4	72.2	70.4	72.2	70.4	72.2
60070007	CA	Butte	68.9	71.0	68.8	70.9	68.8	70.9	68.8	70.9
60090001	CA	Calaveras	70.9	71.9	70.8	71.8	70.8	71.8	70.8	71.8
60170010	CA	El Dorado	76.3	78.7	76.2	78.7	76.2	78.7	76.2	78.7
60170020	CA	El Dorado	74.3	76.2	74.2	76.1	74.2	76.1	74.2	76.1
60190007	CA	Fresno	80.4	82.2	80.3	82.2	80.3	82.2	80.3	82.2
60190011	CA	Fresno	82.9	83.8	82.8	83.8	82.8	83.8	82.8	83.8
60190242	CA	Fresno	79.5	81.1	79.4	81.1	79.4	81.1	79.4	81.1
60194001	CA	Fresno	82.8	84.4	82.7	84.3	82.7	84.3	82.7	84.3
60195001	CA	Fresno	83.7	86.4	83.6	86.4	83.6	86.4	83.6	86.4
60250005	CA	Imperial	76.3	76.6	76.2	76.6	76.2	76.6	76.2	76.6

Site ID	State	County	2023 Avg	2023 Max	Proposed Avg	Proposed Max	Less Stringent Avg	Less Stringent Max	More Stringent Avg	More Stringent Max
60251003	CA	Imperial	75.4	75.4	75.3	75.3	75.3	75.3	75.3	75.3
60290007	CA	Kern	82.8	84.0	82.7	84.0	82.7	84.0	82.7	84.0
60290008	CA	Kern	79.1	81.0	79.0	81.0	79.0	81.0	79.0	81.0
60290011	CA	Kern	78.8	80.4	78.7	80.4	78.7	80.4	78.7	80.4
60290014	CA	Kern	81.3	83.2	81.2	83.2	81.2	83.2	81.2	83.2
60290232	CA	Kern	74.9	77.5	74.8	77.4	74.8	77.4	74.8	77.4
60292012	CA	Kern	84.1	84.7	84.0	84.8	84.0	84.8	84.0	84.8
60295002	CA	Kern	82.4	84.0	82.3	84.0	82.3	84.0	82.3	84.0
60311004	CA	Kings	76.9	77.6	76.8	77.5	76.8	77.5	76.8	77.5
60370002	CA	Los Angeles	88.0	92.4	87.9	92.4	87.9	92.4	87.9	92.4
60370016	CA	Los Angeles	93.4	96.2	93.3	96.2	93.3	96.2	93.3	96.2
60371103	CA	Los Angeles	70.5	71.5	70.4	71.5	70.4	71.5	70.4	71.5
60371201	CA	Los Angeles	82.7	85.3	82.6	85.2	82.6	85.2	82.6	85.2
60371602	CA	Los Angeles	73.6	73.9	73.5	73.9	73.5	73.9	73.5	73.9
60371701	CA	Los Angeles	85.6	88.4	85.5	88.4	85.5	88.4	85.5	88.4
60372005	CA	Los Angeles	80.7	81.9	80.6	81.9	80.6	81.9	80.6	81.9
60376012	CA	Los Angeles	91.6	93.4	91.5	93.4	91.5	93.4	91.5	93.4
60379033	CA	Los Angeles	80.7	82.2	80.6	82.3	80.6	82.3	80.6	82.3
60390004	CA	Madera	75.7	78.3	75.6	78.2	75.6	78.2	75.6	78.2
60392010	CA	Madera	77.0	78.2	76.9	78.2	76.9	78.2	76.9	78.2
60430003	CA	Mariposa	74.2	77.1	74.1	77.1	74.1	77.1	74.1	77.1
60470003	CA	Merced	74.7	75.9	74.6	75.9	74.6	75.9	74.6	75.9
60570005	CA	Nevada	78.1	81.5	78.0	81.4	78.0	81.4	78.0	81.4
60592022	CA	Orange	72.5	72.8	72.4	72.8	72.4	72.8	72.4	72.8
60595001	CA	Orange	72.3	73.0	72.2	73.0	72.2	73.0	72.2	73.0
60610003	CA	Placer	77.1	79.8	77.0	79.8	77.0	79.8	77.0	79.8
60610004	CA	Placer	71.9	77.0	71.8	77.0	71.8	77.0	71.8	77.0
60610006	CA	Placer	72.8	73.7	72.7	73.7	72.7	73.7	72.7	73.7
60650008	CA	Riverside	71.0	73.3	70.9	73.3	70.9	73.3	70.9	73.3
60650012	CA	Riverside	85.9	88.3	85.8	88.3	85.8	88.3	85.8	88.3
60650016	CA	Riverside	72.0	72.9	71.9	72.9	71.9	72.9	71.9	72.9

Site ID	State	County	2023 Avg	2023 Max	Proposed Avg	Proposed Max	Less Stringent Avg	Less Stringent Max	More Stringent Avg	More Stringent Max
60651016	CA	Riverside	89.8	90.9	89.7	90.9	89.7	90.9	89.7	90.9
60652002	CA	Riverside	76.4	78.5	76.3	78.5	76.3	78.5	76.3	78.5
60655001	CA	Riverside	80.5	82.6	80.4	82.6	80.4	82.6	80.4	82.6
60656001	CA	Riverside	83.5	84.1	83.4	84.1	83.4	84.1	83.4	84.1
60658001	CA	Riverside	89.5	90.7	89.4	90.6	89.4	90.6	89.4	90.6
60658005	CA	Riverside	87.9	90.7	87.8	90.6	87.8	90.6	87.8	90.6
60659001	CA	Riverside	80.8	82.9	80.7	82.9	80.7	82.9	80.7	82.9
60670002	CA	Sacramento	71.4	71.7	71.3	71.7	71.3	71.7	71.3	71.7
60670012	CA	Sacramento	74.8	75.4	74.7	75.5	74.7	75.5	74.7	75.5
60675003	CA	Sacramento	70.2	71.7	70.1	71.8	70.1	71.8	70.1	71.8
60710001	CA	San Bernardino	74.5	75.4	74.4	75.4	74.4	75.4	74.4	75.4
60710005	CA	San Bernardino	100.3	101.8	100.2	101.8	100.2	101.8	100.2	101.8
60710012	CA	San Bernardino	87.3	90.1	87.2	90.1	87.2	90.1	87.2	90.1
60710306	CA	San Bernardino	76.8	78.6	76.7	78.6	76.7	78.6	76.7	78.6
60711004	CA	San Bernardino	97.2	100.2	97.1	100.2	97.1	100.2	97.1	100.2
60711234	CA	San Bernardino	70.6	74.2	70.5	74.3	70.5	74.3	70.5	74.3
60712002	CA	San Bernardino	90.1	91.3	90.0	91.3	90.0	91.3	90.0	91.3
60714001	CA	San Bernardino	82.6	83.3	82.5	83.3	82.5	83.3	82.5	83.3
60714003	CA	San Bernardino	95.2	98.0	95.1	98.0	95.1	98.0	95.1	98.0
60719002	CA	San Bernardino	80.1	81.6	80.1	81.7	80.1	81.7	80.1	81.7
60719004	CA	San Bernardino	99.5	101.6	99.4	101.6	99.4	101.6	99.4	101.6
60731006	CA	San Diego	76.9	77.9	76.8	77.8	76.8	77.8	76.8	77.8
60773005	CA	San Joaquin	71.3	72.8	71.2	72.9	71.2	72.9	71.2	72.9
60990005	CA	Stanislaus	75.4	76.3	75.3	76.3	75.3	76.3	75.3	76.3
60990006	CA	Stanislaus	77.5	77.8	77.4	77.8	77.4	77.8	77.4	77.8
61070006	CA	Tulare	79.1	80.3	79.0	80.3	79.0	80.3	79.0	80.3

Site ID	State	County	2023 Avg	2023 Max	Proposed Avg	Proposed Max	Less Stringent Avg	Less Stringent Max	More Stringent Avg	More Stringent Max
61070009	CA	Tulare	82.6	82.6	82.5	82.5	82.5	82.5	82.5	82.5
61072002	CA	Tulare	75.5	77.6	75.4	77.6	75.4	77.6	75.4	77.6
61072010	CA	Tulare	77.0	78.8	76.9	78.8	76.9	78.8	76.9	78.8
61090005	CA	Tuolumne	75.6	77.8	75.5	77.7	75.5	77.7	75.5	77.7
61112002	CA	Ventura	70.9	71.6	70.8	71.5	70.8	71.5	70.8	71.5
80350004	CO	Douglas	71.7	72.3	71.6	72.2	71.6	72.2	71.6	72.2
80590006	CO	Jefferson	72.6	73.3	72.5	73.1	72.5	73.1	72.5	73.1
80590011	CO	Jefferson	73.8	74.4	73.7	74.4	73.7	74.4	73.7	74.4
90010017	CT	Fairfield	73.0	73.7	72.9	73.6	72.9	73.6	72.9	73.6
90013007	CT	Fairfield	74.2	75.1	74.1	75.0	74.1	75.0	74.1	75.0
90019003	CT	Fairfield	76.1	76.4	76.0	76.2	76.0	76.2	76.0	76.2
90099002	CT	New Haven	71.8	73.9	71.7	73.8	71.7	73.8	71.7	73.8
170310001	IL	Cook	69.6	73.4	69.5	73.4	69.5	73.4	69.5	73.4
170310032	IL	Cook	69.8	72.4	69.7	72.4	69.7	72.4	69.7	72.4
170310076	IL	Cook	69.3	72.1	69.2	72.1	69.2	72.1	69.2	72.1
170314201	IL	Cook	69.9	73.4	69.8	73.4	69.8	73.4	69.8	73.4
170317002	IL	Cook	70.1	73.0	70.0	73.0	70.0	73.0	70.0	73.0
320030075	NV	Clark	70.0	71.0	69.9	70.9	69.9	70.9	69.9	70.9
420170012	PA	Bucks	70.7	72.2	70.6	72.2	70.6	72.2	70.6	72.1
480391004	TX	Brazoria	70.1	72.3	70.0	72.1	70.0	72.1	70.0	72.1
481210034	TX	Denton	70.4	72.2	70.3	72.2	70.3	72.2	70.3	72.1
482010024	TX	Harris	75.2	76.8	75.1	76.6	75.1	76.6	75.1	76.6
482010055	TX	Harris	71.0	72.0	70.9	71.9	70.9	71.9	70.9	71.9
482011034	TX	Harris	70.3	71.6	70.2	71.4	70.2	71.4	70.2	71.4
482011035	TX	Harris	68.0	71.6	67.9	71.4	67.9	71.4	67.9	71.4
490110004	UT	Davis	72.9	75.1	72.8	75.0	72.8	75.0	72.8	75.0
490353006	UT	Salt Lake	73.6	75.3	73.5	75.1	73.5	75.1	73.5	75.1
490353013	UT	Salt Lake	74.4	74.9	74.3	74.8	74.3	74.8	74.3	74.8
490570002	UT	Weber	70.6	72.5	70.5	72.4	70.5	72.4	70.5	72.4
490571003	UT	Weber	70.5	71.5	70.4	71.3	70.4	71.3	70.4	71.3
550590019	WI	Kenosha	72.8	73.7	72.7	73.6	72.7	73.6	72.7	73.6
550590025	WI	Kenosha	69.2	72.3	69.1	72.2	69.1	72.2	69.1	72.2
551010020	WI	Racine	71.3	73.2	71.2	73.1	71.2	73.1	71.2	73.1

Table 3B-6. Projected average and maximum design values for the 2026 base case, the proposed case, less stringent case, and more stringent case (ppb).

Site ID	State	County	2026 Avg	2026 Max	Proposed Avg	Proposed Max	Less Stringent Avg	Less Stringent Max	More Stringent Avg	More Stringent Max
40278011	AZ	Yuma	70.1	71.8	70.0	71.7	70.0	71.7	70.0	71.7
60090001	CA	Calaveras	70.2	71.1	70.0	70.9	70.0	70.9	70.0	70.9
60170010	CA	El Dorado	75.0	77.4	74.8	77.2	74.8	77.2	74.8	77.2
60170020	CA	El Dorado	73.2	75.0	73.0	74.8	73.0	74.8	73.0	74.8
60190007	CA	Fresno	79.5	81.3	79.3	81.1	79.3	81.1	79.3	81.1
60190011	CA	Fresno	81.9	82.8	81.7	82.6	81.7	82.6	81.7	82.6
60190242	CA	Fresno	78.7	80.3	78.5	80.1	78.5	80.1	78.5	80.1
60194001	CA	Fresno	81.8	83.3	81.6	83.1	81.6	83.1	81.6	83.1
60195001	CA	Fresno	82.7	85.4	82.5	85.2	82.5	85.2	82.5	85.2
60250005	CA	Imperial	76.2	76.5	76.1	76.4	76.1	76.4	76.1	76.4
60251003	CA	Imperial	75.3	75.3	75.2	75.2	75.2	75.2	75.2	75.2
60290007	CA	Kern	82.2	83.4	81.9	83.1	81.9	83.1	81.9	83.1
60290008	CA	Kern	78.6	80.5	78.3	80.2	78.3	80.2	78.3	80.2
60290011	CA	Kern	78.3	79.9	78.1	79.7	78.1	79.7	78.1	79.7
60290014	CA	Kern	80.7	82.6	80.5	82.4	80.5	82.4	80.4	82.3
60290232	CA	Kern	74.4	76.9	74.2	76.7	74.2	76.7	74.2	76.7
60292012	CA	Kern	83.4	84.1	83.2	83.9	83.2	83.9	83.2	83.9
60295002	CA	Kern	81.7	83.3	81.5	83.0	81.5	83.1	81.4	83.0
60311004	CA	Kings	76.0	76.6	75.8	76.4	75.8	76.4	75.8	76.4
60370002	CA	Los Angeles	87.1	91.5	86.9	91.3	86.9	91.3	86.9	91.3
60370016	CA	Los Angeles	92.4	95.2	92.2	94.9	92.2	95.0	92.1	94.9
60371201	CA	Los Angeles	81.8	84.3	81.6	84.1	81.6	84.1	81.6	84.1
60371602	CA	Los Angeles	73.0	73.3	72.9	73.2	72.9	73.2	72.9	73.2
60371701	CA	Los Angeles	84.6	87.4	84.4	87.2	84.4	87.2	84.4	87.2
60372005	CA	Los Angeles	79.9	81.1	79.7	80.9	79.7	80.9	79.7	80.9
60376012	CA	Los Angeles	90.6	92.4	90.4	92.2	90.4	92.2	90.4	92.2
60379033	CA	Los Angeles	79.8	81.4	79.6	81.2	79.6	81.2	79.6	81.2

Site ID	State	County	2026 Avg	2026 Max	Proposed Avg	Proposed Max	Less Stringent Avg	Less Stringent Max	More Stringent Avg	More Stringent Max
60390004	CA	Madera	75.0	77.5	74.8	77.3	74.8	77.3	74.8	77.3
60392010	CA	Madera	76.1	77.3	75.9	77.1	75.9	77.1	75.9	77.1
60430003	CA	Mariposa	74.0	76.9	73.9	76.8	73.9	76.8	73.9	76.8
60470003	CA	Merced	73.9	75.1	73.7	74.9	73.7	74.9	73.7	74.9
60570005	CA	Nevada	77.2	80.5	77.0	80.3	77.0	80.3	77.0	80.3
60592022	CA	Orange	71.8	72.1	71.6	71.9	71.6	71.9	71.6	71.9
60595001	CA	Orange	71.7	72.4	71.5	72.2	71.5	72.2	71.5	72.2
60610003	CA	Placer	75.9	78.6	75.7	78.4	75.7	78.4	75.7	78.4
60610004	CA	Placer	70.9	76.0	70.7	75.8	70.7	75.8	70.7	75.8
60610006	CA	Placer	71.7	72.6	71.5	72.4	71.5	72.4	71.5	72.4
60650008	CA	Riverside	70.4	72.7	70.2	72.5	70.3	72.6	70.2	72.5
60650012	CA	Riverside	84.9	87.3	84.6	87.0	84.7	87.1	84.6	87.0
60650016	CA	Riverside	71.1	72.0	70.9	71.8	70.9	71.8	70.9	71.8
60651016	CA	Riverside	88.8	89.9	88.5	89.6	88.6	89.7	88.5	89.6
60652002	CA	Riverside	75.7	77.8	75.5	77.6	75.6	77.7	75.5	77.6
60655001	CA	Riverside	79.6	81.7	79.4	81.5	79.4	81.5	79.4	81.5
60656001	CA	Riverside	82.5	83.1	82.3	82.9	82.3	82.9	82.3	82.9
60658001	CA	Riverside	88.6	89.7	88.3	89.4	88.4	89.5	88.3	89.4
60658005	CA	Riverside	87.0	89.7	86.8	89.5	86.8	89.5	86.8	89.5
60659001	CA	Riverside	79.9	82.0	79.7	81.8	79.7	81.8	79.7	81.8
60670012	CA	Sacramento	73.6	74.3	73.4	74.1	73.4	74.1	73.4	74.1
60710001	CA	San Bernardino	74.0	74.9	73.8	74.7	73.9	74.8	73.8	74.7
60710005	CA	San Bernardino	99.2	100.7	98.9	100.4	98.9	100.4	98.9	100.4
60710012	CA	San Bernardino	86.4	89.2	86.2	89.0	86.2	89.0	86.2	89.0
60710306	CA	San Bernardino	76.0	77.8	75.8	77.6	75.8	77.6	75.8	77.6
60711004	CA	San Bernardino	96.1	99.1	95.8	98.8	95.8	98.8	95.8	98.8
60711234	CA	San Bernardino	70.3	74.0	70.2	73.9	70.2	73.9	70.2	73.9
60712002	CA	San Bernardino	89.2	90.4	88.9	90.1	89.0	90.2	88.9	90.1
60714001	CA	San Bernardino	81.7	82.4	81.5	82.2	81.5	82.2	81.5	82.2

Site ID	State	County	2026 Avg	2026 Max	Proposed Avg	Proposed Max	Less Stringent Avg	Less Stringent Max	More Stringent Avg	More Stringent Max
60714003	CA	San Bernardino	94.2	97.0	93.9	96.7	94.0	96.8	93.9	96.7
60719002	CA	San Bernardino	79.3	80.9	79.1	80.7	79.2	80.8	79.1	80.7
60719004	CA	San Bernardino	98.5	100.6	98.2	100.3	98.2	100.3	98.2	100.3
60731006	CA	San Diego	76.1	77.0	76.0	76.9	76.0	76.9	75.9	76.8
60773005	CA	San Joaquin	70.8	72.4	70.6	72.2	70.6	72.2	70.6	72.2
60990005	CA	Stanislaus	74.7	75.6	74.5	75.4	74.5	75.4	74.5	75.4
60990006	CA	Stanislaus	76.7	77.0	76.5	76.8	76.5	76.8	76.5	76.8
61070006	CA	Tulare	78.2	79.4	78.1	79.3	78.1	79.3	78.0	79.2
61070009	CA	Tulare	81.6	81.6	81.5	81.5	81.5	81.5	81.4	81.4
61072002	CA	Tulare	74.3	76.4	74.2	76.3	74.2	76.3	74.1	76.2
61072010	CA	Tulare	75.9	77.7	75.7	77.5	75.7	77.5	75.7	77.5
61090005	CA	Tuolumne	75.0	77.1	74.8	76.9	74.8	76.9	74.8	76.9
80350004	CO	Douglas	70.5	71.1	70.3	70.9	70.4	71.0	70.3	70.9
80590006	CO	Jefferson	71.7	72.3	71.5	72.1	71.6	72.2	71.5	72.1
80590011	CO	Jefferson	72.6	73.3	72.4	73.1	72.5	73.2	72.4	73.1
90010017	CT	Fairfield	71.5	72.2	71.1	71.8	71.2	71.9	70.9	71.6
90013007	CT	Fairfield	72.8	73.7	72.2	73.1	72.3	73.2	72.0	72.9
90019003	CT	Fairfield	74.6	74.8	74.1	74.3	74.2	74.4	74.0	74.2
90099002	CT	New Haven	70.4	72.4	69.8	71.8	69.9	71.9	69.7	71.7
170310001	IL	Cook	68.7	72.5	68.2	72.0	68.4	72.2	68.2	71.9
170310032	IL	Cook	69.1	71.7	68.8	71.4	68.9	71.5	68.8	71.4
170310076	IL	Cook	68.5	71.3	68.0	70.8	68.2	71.0	68.0	70.8
170314201	IL	Cook	68.9	72.4	68.5	71.9	68.6	72.1	68.4	71.9
170317002	IL	Cook	69.1	72.0	68.6	71.5	68.8	71.6	68.6	71.4
480391004	TX	Brazoria	69.1	71.2	67.7	69.7	68.1	70.2	67.5	69.6
482010024	TX	Harris	74.2	75.7	72.9	74.4	73.2	74.7	72.7	74.2
490110004	UT	Davis	71.7	73.9	71.4	73.5	71.5	73.7	71.3	73.5
490353006	UT	Salt Lake	72.5	74.1	72.2	73.7	72.3	73.9	72.2	73.7
490353013	UT	Salt Lake	73.5	74.0	73.1	73.6	73.2	73.7	73.1	73.6
490570002	UT	Weber	69.8	71.7	69.4	71.3	69.6	71.4	69.4	71.3
550590019	WI	Kenosha	71.7	72.6	71.1	72.0	71.3	72.2	71.1	72.0
550590025	WI	Kenosha	68.1	71.1	67.5	70.5	67.7	70.7	67.5	70.4
551010020	WI	Racine	70.2	72.1	69.6	71.5	69.8	71.7	69.6	71.5

3B.4 Projected Impacts on Downwind Contributions

As noted above, the method for projecting design values in 2023 and 2026 for each alternative control case involved estimating the change in contribution from each state to each receptor for each case. We compared the contributions from each alternative control case to the corresponding contributions in the 2023 and 2026 base cases. For each of these years, we evaluated the reductions in contributions for each linkage to identify the largest reduction from each upwind state to a linked downwind receptor. In 2023, the largest reduction between the base case contributions and each of the three alternative cases were 0.01 ppb or less. In 2026, impacts on upwind state contributions are greater than in 2023, which is consistent with the overall larger amount of NOx reduction in 2026 compared to 2023. In 2026 we found that 19 of the 24 linked upwind states are projected to have their downwind contribution reduced by 0.01 ppb or more to at least one receptor. In 12 of these 19 states, the largest reduction in downwind contribution is at least 0.05 ppb. In half of these 12 states, the largest reduction in downwind contribution is 0.10 ppb or more. In Table 3B-7 we provide the largest impact on downwind contributions to a linked receptor for those 19 upwind states that are projected to have a reduction in contribution of 0.01 ppb or more to at least one downwind receptor. A review of the impact on contributions of the emissions reductions in the alternative control cases indicates that each state that is linked in the 2023 base case and in the 2026 base case is still linked to at least one downwind receptor in the alternative control cases.

Table 3B-7. Largest reduction in downwind contribution for 19 upwind states for each alternative control case

State	Proposed vs Base	Less vs Base	More vs Base
AR	0.16	0.04	0.16
CA	0.03	0.02	0.03
IN	0.31	0.18	0.32
KY	0.10	0.06	0.11
LA	0.58	0.42	0.66
MI	0.08	0.06	0.08
MN	0.01	0.00	0.01
MO	0.10	0.07	0.10
MS	0.07	0.03	0.07
NY	0.03	0.02	0.07
OH	0.06	0.05	0.06

OK	0.02	0.02	0.02
PA	0.15	0.14	0.27
TX	0.04	0.03	0.05
UT	0.08	0.05	0.08
VA	0.03	0.03	0.03
WI	0.08	0.02	0.09
WV	0.02	0.01	0.02
WY	0.06	0.02	0.06

CHAPTER 4: COST, EMISSIONS, AND ENERGY IMPACTS

Overview

This chapter reports the compliance costs, emissions, and energy analyses performed for the proposed Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (FIP for the 2015 ozone NAAQS). EPA used the Integrated Planning Model (IPM)[1] to conduct the electric generating units (EGU) analysis discussed in this chapter and the Control Strategy Tool (CoST)[2], the Control Measures Database (CMDB)[3], and the 2019 emissions inventory to conduct a screening assessment 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_X) ozone season emissions budgets in the 25 states subject to this action. These regulatory control alternatives impose different budget levels. The different budget levels are calculated assuming the application of different NO_X mitigation technologies. The chapter also presents three regulatory control alternatives for non-EGUs that differ in the number of sources subject to emission limits.

The chapter is organized as follows: following a summary of the regulatory control alternatives analyzed and a summary of 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. We then present a summary of the results of the non-EGU screening assessment for 2026. Section 4.6 of this chapter describes the relationship between the compliance cost estimates and social costs.

4.1 Regulatory Control Alternatives

The proposal establishes NO_X emissions budgets requiring fossil fuel-fired power plants (EGUs) in 25 states to participate in an allowance-based ozone season (May 1 through September 30) trading program beginning in 2023. The EGUs covered by the proposed FIPs and

[1] Information on IPM can be found at the following link: https://www.epa.gov/airmarkets/power-sector-modeling.
[2] Further information on CoST can be found at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.
[3] The CMDB is available at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

subject to the budget are fossil-fired EGUs with >25 megawatt (MW) capacity. For details on the derivation of these budgets, please see Section VI.C. of the preamble.

The proposed FIP requirements establish ozone season NO_X emissions budgets for EGUs in 25 states starting in 2023 (Alabama, Arkansas, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming) and require EGUs in these states to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.[4] EPA is proposing to amend existing FIPs for 12 states currently participating in the CSAPR NO_X Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) to replace their existing emissions budgets established in the Revised CSAPR Update with new emissions budgets. For eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program under State Implementation Plans (SIPs) or FIPs, EPA is proposing to issue new FIPs for two states (Alabama and Missouri) and amend existing FIPs for six states (Arkansas, Mississippi, Oklahoma, Tennessee, Texas, and Wisconsin) to transition EGU sources in these states to the revised Group 3 Trading Program beginning with the 2023 ozone season. EPA proposes to issue new FIPs for five states not currently covered by any CSAPR NO_X ozone season trading program: Delaware, Minnesota, Nevada, Utah, and Wyoming. In 2026 the seasonal NOx emissions budgets are reduced further, in particular for 23 of these states (Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming). In addition, beginning in the 2027 ozone season, coal facilities greater than 100 MW lacking SCR controls and certain oil/gas steam facilities greater than 100 MW that lack existing SCR controls located in these 23 states must meet daily emission rate limits, effectively forcing affected units to install new SCR controls, find other means of compliance, or retire. States that do not have additional control measures assumed in 2026

[4] As explained in Section VI.C.1 of the preamble, EPA proposes finding that EGU sources within the State of California are sufficiently controlled such that no further emission reductions are needed from them to eliminate significant contribution to downwind states.

continue to remain part of the revised group 3 Trading Program.

In the proposal, we introduce additional features to the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets over time and backstop daily emission rate limits for most coal-fired units, that were not included in previous CSAPR NO_X 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. For affected uncontrolled units in the 23 state group, starting in 2026, this analysis imposes an emission rate constraint that forces affected units to either install new SCR retrofits, find other means of compliance, or retire.[5] The analysis does not explicitly capture the dynamic budget adjustments over time, 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. For details of the controls modeled for each of the regulatory control alternatives please see Table 4-2 below.

The proposal also includes NO_X emissions limitations with an initial compliance date of 2026 applicable to certain non-EGU stationary sources in 23 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. The proposed rule establishes NO_X emissions limitations during the ozone season for the unit types listed in Table 4-1 below. A more detailed summary of the proposed emissions limits can be found in Section I.B. of the preamble.

[5] The proposed rule assumes SCR retrofit potential starting in 2026 and it is reflected in the 2026 state emission budgets. The daily backstop emission rate does not apply until 2027, but the majority of units retrofitting are anticipated to do so by 2026 to assist with the 2026 state emissions budget compliance. EPA's IPM model run years are 2026 and 2028. The SCR compliance behavior is generally expected to occur no later than 2027, and in 2026 in many cases. Therefore, EPA models this daily backstop emission rate in 2026 (when choosing between model run year 2026 and 2028) to conservatively reflect compliance cost in the first year in which the technology is in place for some units.

Table 4-1. Non-EGU Emissions Unit Types, Emissions Limits, and Industries

Emissions Unit Type	Emissions Limit	Industry	NAICS
Reciprocating internal combustion engines	g/hp-hr	Pipeline Transportation of Natural Gas	4862
Kilns	lb/ton of clinker	Cement and Concrete Product Manufacturing	3273
Boilers and furnaces	Depending on equipment type - lb/mmBtu, lb/ton of steel, lb/ton, lb/ton coal pushed, lb/ton coal charged, work practice standards	Iron and Steel Mills and Ferroalloy Manufacturing	3311
Furnaces	lb/ton glass produced	Glass and Glass Product Manufacturing	3272
Impactful boilers*	lbs NOx/mmBtu	Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills	3251, 3241, 3221

North American Industry Classification System (NAICS)
*Impactful boilers are boilers with design capacity of 100 mmBtu/hr or greater.

This regulatory impact analysis (RIA) evaluates the benefits, costs and certain impacts of compliance with three regulatory control alternatives: the proposed FIP for the 2015 ozone NAAQS, a less-stringent alternative, and a more-stringent alternative. Table 4-2 below presents the less stringent alternatives, proposed 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

Regulatory Control Alternative	NO_X Controls Implemented for EGUs within IPM
Less Stringent Alternative	1) 2023 onwards: Shift generation to minimize costs 2) 2023 onwards: Fully operate existing SCRs during ozone season 3) 2023 onwards: Fully operate existing SNCRs during ozone season 4) In 2023 install state-of-the-art combustion controls 5) In 2028 model run year, impose backstop emission rate limits on coal units greater than 100 MW within the 23-state region that lack SCR controls, forcing units to retrofit or retire. 6) In 2028 model run year, impose backstop emission rate limits on oil/gas steam units greater than 100 MW that operated at a greater than 20% capacity factor historically within the 23-state region that lack SCR controls, forcing units to retrofit or retire.[6]
Proposed Rule	(All Controls above and)

[6] The 20% capacity factor cutoff applied is representative of the fleet of O/G steam units assumed to have SCR retrofit potential in its state budgets. In the proposal, EPA defined this segment using 150 tons per season cutoff, which provides a similar size of the O/G steam fleet as the 20% capacity factor value used in this analysis.

Regulatory Control Alternative	NO_X Controls Implemented for EGUs within IPM
	7) In 2026, impose backstop emission rate limits on coal units greater than 100 MW within the 23-state region that lack SCR controls, forcing units to retrofit or retire. 8) In 2026, impose backstop emission rate limits on oil/gas steam units greater than 100 MW that operated at a greater than 20% capacity factor historically within the 23-state region that lack SCR controls, forcing units to retrofit or retire.
More Stringent Alternative	(Controls 1 – 4, 7 and 8 above and) 9) In 2026, impose backstop emission rate limits on all oil/gas steam units greater than 100 MW within the 23-state region that lack SCR controls, forcing units to retrofit or retire.
	NO_X Emissions Limits for Non-EGUs – Emissions Unit Types and Industries
Less Stringent Alternative	1) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas, 2) Kilns in Cement and Cement Product Manufacturing, 3) Boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing, 4) Furnaces in Glass and Glass Product Manufacturing, and
Proposed Rule	(All emissions unit types and industries above and) 5) *Impactful* boilers* in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.
More Stringent Alternative	(All emissions unit types and industries above and) 6) *All* boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

*Impactful boilers are boilers with design capacity of 100 mmBtu/hr or greater.

4.1.1 EGU Regulatory Control Alternatives Analyzed

The illustrative emission budgets in this RIA represent EGU NO_X ozone season emission budgets for each state in 2023 and in 2026.[7] This RIA analyzes the proposed FIP for the 2015 ozone NAAQS emission budgets, as well as a more and a less stringent alternative to the proposed FIP for the 2015 ozone NAAQS. The more and less stringent alternatives differ from the proposed rule in that they set different NO_X ozone season emission budgets for the affected EGUs and different dates for compliance with backstop emission rate limits. All three scenarios use emission budgets that were developed using uniform control stringency represented by $1,800 per ton of NO_X (2016$) in 2023 and $11,000 per ton of NO_X (2016$) in 2026. The less-stringent alternative imposes backstop emission rate limits in the 2028 run year[8] (reflective of

[7] The budget setting process is described in section VII.B. of the preamble and in detail in the Ozone Transport Policy Analysis Proposed Rule Technical Support Document (TSD).

[8] 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:

imposition in the 2027 calendar year), while the proposed rule and more stringent alternative impose backstop emission rate limits in the 2025 run year (reflective of imposition in the 2026 calendar year) that force uncontrolled units to either install controls or retire. The backstop emission rate limits are imposed on all coal units within the 23 state region that are greater than 100 MW and lack SCR controls (excepting circulating fluidized bed (CFB) units). The emission rate limits are also imposed on all oil/gas steam units within the linked states that are greater than 100 MW and lack SCR controls that operated at a greater than 20 percent historical capacity factor. In addition to the backstop rate limits present in the proposed rule and the less stringent alternative, the more stringent alternative also imposes backstop emission rate limits on all oil/gas steam units in the affected states that are greater than 100 MW, lack SCR controls, and have operated at below a 20 percent capacity factor historically.

All three alternatives are illustrative in nature in part because the budgets included in the proposed FIP for the 2015 ozone NAAQS alternative differ slightly from the budgets imposed in the modeling of these RIA alternatives. Furthermore, the proposed alternative analyzed herein assumes oil/gas steam units are subject to backstop emission rate limits, whereas the proposed rule does not impose those limits. That is because subsequent to completion of the analysis of these three alternatives, EPA made updates to budgets in the proposal itself. In particular, the budgets proposed in the rule account for emission reductions commensurate with the installation of SCR at oil/gas steam units greater than 100 MW without an SCR and a three-year (2019-21) average of ozone season emissions of at least 150 tons beginning in 2026. The proposed rule scenario assumes emission reductions commensurate with installation of SCRs at oil/gas steam units greater than 100 MW without an SCR and a three-year average capacity factor of greater than 20% beginning in 2026. Additionally, backstop emission rates are not applicable to this oil/gas steam capacity in the proposed rule, while the proposed rule scenario assumes these units are subject to backstop emission rate limits. In the proposed rule, for the 12 Revised CSAPR Update states the 2023 budgets assume that state-of-the-art combustion controls are installed in 2023, while combustion controls in the remaining 13 states are not assumed to be installed until 2024. Under the modeling for the proposed rule, the illustrative budget assumes that all 25 states

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https://www.epa.gov/system/files/documents/2021-09/epa-platform-v6-summer-2021-reference-case-09-11-21-v6.pdf install combustion controls in 2023. Installation of state-of-the-art combustion controls is an exogenous input to the model, and state-of-the-art combustion control installations are imposed in all 25 states in 2023. Finally, the Engineering Analysis used to develop the illustrative budgets relied on 2019 historical data, while the Engineering Analysis used to develop the proposed budgets relied on 2021 historical data.

EPA finds that the three illustrative regulatory control alternatives presented in this RIA provide a reasonable approximation of the impacts of the proposed rule, as well as an evaluation of the relative impacts of two regulatory alternatives. This finding is supported by a side analysis of the costs and impacts (but not the benefits) of the emission budgets included in the proposed FIP for the 2015 Ozone NAAQS, which is provided in the docket for this proposed rulemaking.

Table 4-3. reports the illustrative EGU NO_X ozone season emission budgets that are evaluated in this RIA for the 2023 and 2025 IPM run years. As described above, starting in 2023, emissions from affected EGUs in the 25 states cannot exceed the sum of emissions budgets but for the ability to use banked allowances from previous years for compliance. For individual states, emissions cannot exceed 121% of the state emission budget (the assurance levels). In these RIA scenarios, no further reductions in budgets occur after 2026, and budgets remain in place for future years. These budgets are imposed in addition to the control measures outlined in Table 4-2.

Table 4-3. Illustrative NO_X Ozone Season Emission Budgets (Tons) Evaluated by IPM Run Year

Region	Proposed Rule			Less Stringent Alternative			More Stringent Alternative	
	2023	2025		2023	2025		2023	2025
Alabama	7,444	7,444		7,444	7,444		7,445	7,445
Arkansas	8,848	4,019		8,848	4,019		8,848	3,837
Delaware	333	333		333	333		204	204
Illinois	6,985	5,396		6,985	5,396		6,984	5,354
Indiana	11,315	7,798		11,315	7,798		11,315	7,797
Kentucky	11,410	6,897		11,410	6,897		11,410	6,821
Louisiana	13,698	4,988		13,698	4,988		13,698	4,255
Maryland	1,245	1,325		1,245	1,325		1,245	1,226
Michigan	10,896	7,779		10,896	7,779		10,897	7,732
Minnesota	4,072	2,371		4,072	2,371		4,393	2,614
Mississippi	6,431	2,709		6,431	2,709		6,431	2,048
Missouri	10,211	7,467		10,211	7,467		10,211	7,467
Nevada	2,392	1,028		2,392	1,028		940	745

Region	Proposed Rule			Less Stringent Alternative			More Stringent Alternative	
	2023	2025		2023	2025		2023	2025
New Jersey	1,099	1,099		1,099	1,099		1,098	1,098
New York	3,283	2,762		3,283	2,762		3,283	2,331
Ohio	8,612	8,437		8,612	8,437		8,612	8,395
Oklahoma	8,765	4,229		8,765	4,229		8,764	3,782
Pennsylvania	8,340	8,008		8,340	8,008		8,340	7,274
Tennessee	4,394	4,394		4,394	4,394		4,393	4,393
Texas	41,169	23,898		41,169	23,898		41,169	22,188
Utah	9,526	1,760		9,526	1,760		9,360	1,610
Ute	2,144	409		2,144	409		2,144	409
Virginia	3,856	3,172		3,856	3,172		3,856	2,955
West Virginia	12,015	9,125		12,015	9,125		12,015	9,125
Wisconsin	4,892	2,752		4,892	2,752		4,892	2,733
Wyoming	8,684	4,215		8,684	4,215		8,639	4,158
Aggregated State Emission Budgets	**212,059**	**133,814**		**212,059**	**133,814**		**210,584**	**127,995**

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, EPA developed an analytical framework and using that framework prepared a screening assessment for 2026 to estimate emissions reduction potential from impactful non-EGU industries and non-EGU emissions units. Impactful industries are those that have large, meaningful air quality impacts downwind from potentially controllable NO_X emissions. For additional discussion of impactful industries, see the memorandum titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (non-EGU screening assessment). Impactful emissions units are emissions units with greater than 100 tons per year (tpy) of NO_X emissions.

First, EPA developed an analytical framework using data from 2023. In the analytical framework, EPA identified potential NO_X emissions reductions for non-EGU sources that would result in meaningful air quality improvements in downwind areas. EPA incorporated air quality modeling information, annual emissions, and available information about potential controls to determine which industries, if subject to further control requirements, would have the greatest impact in providing air quality improvements at the downwind receptors. This evaluation in the analytical framework was subject to a marginal cost threshold of up to $7,500 per ton, which EPA determined based on information available to the Agency about existing control device efficiency and cost information. In the framework, EPA identified emissions unit types in seven industries that provide opportunities for NO_X emissions reductions and resulting impacts on air quality at the downwind receptors. Because EPA determined that 2026 was the potential earliest date by which controls on non-EGU emissions units could be installed, EPA used the analytical framework with air quality modeling information for 2026 to prepare a screening assessment for 2026. Results of the screening assessment for 2026 are discussed in Section 4.5. EPA did not estimate emissions reductions of SO_2, $PM_{2.5}$, CO_2 and other pollutants that may be associated with controls on non-EGU emissions units.

As described in Section 4.1, the proposed rule imposes emissions limits on each of the emissions unit types identified in Table 4-1. For non-EGUs, the less stringent alternative assumes there are emissions limits for all emission units from the proposed rule alternative except for impactful boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. The more stringent alternative assumes emissions limits for all emission units from the proposed rule alternative and all boilers, not just impactful boilers, in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

After the non-EGU emissions units are identified in the non-EGU screening assessment, the proposed rule includes a separate evaluation of the emissions limits that are to be applied to each of the non-EGU emissions unit types. The emissions limits are not based on the assumed emission reductions modeled for each emissions unit in the non-EGU screening assessment. Rather, for each emissions unit type, EPA considered the range of emissions limits that currently apply to these sources under other Clean Air Act programs, such as reasonably available control technology (RACT), new source performance standards (NSPS), national emissions standards for hazardous air pollutants (NESHAP), and Ozone Transport Commission (OTC) model rules, to develop an emissions limit that should be achievable by all sources after installing the controls identified in the non-EGU screening assessment.

Table 4-4 below provides a summary of the 2019 ozone season emissions for non-EGUs for the 23 states subject to the proposed FIP in 2026, along with the estimated ozone season reductions for the proposal and the less and more stringent alternatives. The estimated emissions reductions by state for the proposed alternative are from the non-EGU screening assessment, and the estimated reductions by state for the less and more stringent alternatives were estimated for the RIA using the same methodology.

Table 4-4. Ozone Season (OS) NO_X Emissions and Emissions Reductions for the Proposed Rule and the Less and More Stringent Alternatives*

State	2019 OS NOx Emissions	Proposed Rule - OS NOx Reductions	Less Stringent Alternative - OS NOx Reductions	More Stringent Alternative - OS NOx Reductions
AR	8,265	1,654	922	1,654
CA	14,579	1,666	1,598	1,777
IL	16,870	2,452	2,452	2,553
IN	19,604	3,175	2,787	3,175
KY	11,934	2,291	2,291	2,291
LA	35,831	6,769	4,121	6,955
MD	2,365	45	45	45
MI	18,996	2,731	2,731	3,093
MN	17,591	673	673	789
MO	9,109	3,103	3,103	3,103
MS	12,284	1,761	1,577	1,761
NJ	2,025	0	0	29
NV	2,418	0	0	0
NY	6,003	500	389	613
OH	19,729	2,790	2,611	2,814
OK	22,146	3,575	3,575	3,871
PA	15,861	3,284	3,132	3,340
TX	47,135	4,440	4,440	6,596
UT	6,276	757	757	757
VA	7,041	1,563	1,465	1,660
WI	6,571	2,150	677	2,234
WV	9,825	982	982	982
WY	10,335	826	826	826
Totals	322,793	47,186	41,153	50,918

* In the non-EGU screening assessment for 2026, EPA estimated emissions reduction potential from the non-EGU industries and emissions units. In the screening assessment, EPA used CoST to identify emissions units, emissions reductions, and associated compliance costs to evaluate the effects of potential non-EGU emissions control measures and technologies. CoST is designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. The estimates from CoST identify proxies for (1) non-EGU emissions units that have 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. The control cost estimates do not include monitoring, recordkeeping, reporting, or testing costs. This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. For more information on CoST, go to the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

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 prospective air pollution control policies throughout the contiguous United States for the entire electric power system. EPA used IPM to project likely future electricity market conditions with and without the proposed 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, 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 proposed rule and alternatives allows for new combustion controls in the 2023 analysis year.

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. 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.[9]

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 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.[10]

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.[11]

To estimate the annualized costs of additional capital investments in the power sector, 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.[12] It is

[9] 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.

[10] 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.

[11] 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.

[12] 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

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.

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 (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, 2015), the Cross-State Air Pollution Update Rule (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). 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 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[13] 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[14] that are periodically conducted. The Agency has also used the model in a number of comparative

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[13] 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.
[14] http://www2.epa.gov/clean-air-act-overview/benefits-and-costs-clean-air-act

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 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 in the absence of a regulatory action. As such, an IPM baseline run represents an element of the baseline for this RIA.[15] 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 EPA's IPM Baseline run v.6.20

For our analysis of the proposed FIP for the 2015 ozone NAAQS, EPA used 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, v.6.20 Summer 2021 Reference Case[16]) that is used in 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 recently finalized 2020 ELG and CCR rules.[17] The impacts of the Later Model Year Light-Duty Vehicle GHG Emissions Standards are not captured in the baseline, nor is the impact of the Proposed Standards of Performance for New, Reconstructed,

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[15] 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).
[16] https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.20
[17] 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

and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.[18] 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.

4.3.2 Methodology for Evaluating the Regulatory Control Alternatives

To estimate the costs, benefits, and economic and energy market impacts of the proposed FIP for the 2015 ozone NAAQS, EPA conducted quantitative analysis of the three regulatory control alternatives: the proposed 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_X 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, EPA first considered available EGU NO_X mitigation strategies that could be implemented for the 2023 ozone season. EPA considered all widely-used EGU NO_X control strategies: optimizing[19] NO_X 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_X combustion controls; shifting generation to units with lower NO_X emission rates; and installing new SCRs and SNCRs. EPA determined that affected EGUs within the 25 states could implement all of these NO_X mitigation strategies, except installation of new SCRs or SNCRs and state-of-the-art combustion controls, for the 2023 ozone season.[20] After assessing the available NO_x mitigation methods, this RIA projects the system-wide least-cost strategies for complying with the annual budgets and backstop emission rate limits. Least-cost compliance may lead to the application of different control strategies at a given source compared to the particular control

[18] 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
[19] 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_X Mitigation Strategies Proposed Rule TSD.
[20] The analysis assumes that SNCR and SCR optimization is available starting in 2023 and is adopted by all units that do not currently optimize these controls. This compliance choice is an exogenous input into IPM.

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_X 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 or not the unit is subject to any seasonal or annual NOx reduction requirements, and whether the unit installs any additional controls.[21] The proposal's emission control requirements for EGUs only apply during the program's ozone season (May 1 through September 30). Historically, some EGUs have either reduced performance or idled their SCRs during the ozone season to reduce costs of catalyst and ammonia injection in the SCR. This behavior has been observed more frequently during periods when the prevailing allowance price has fallen to very low levels that do not provide an adequate economic incentive to operate the SCR. We would not expect this behavior to occur going forward with the dynamic budgets and backstop emission rate requirements proposed in this policy.

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 or not to operate existing EGU post-combustion NO_X controls (i.e., SCR or SNCR), optimize existing SCRs and SNCRs, and install combustion controls in response to a regulatory emissions requirement.[22] The treatment of these controls in the analyses are described in turn. The operating status of existing post-combustion NO_X controls at a particular EGU in a model scenario is determined by the model user. In order to evaluate compliance with the regulatory alternatives, 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. EPA considers a unit to have optimized use of an SCR if emissions rates are equal to (or below) the "widely achievable"

[21] 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.
[22] 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_X post-combustion controls.

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.[23] Within IPM, units with partially operating or idled SCRs are defined as SCR-equipped units with ozone season NO_X 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 (optimizing partially operating SCR controls or turning on idled SCR controls) are achievable in 2023 and have a uniform control cost of $1,800 per ton (2016$) for coal units 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, 248 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.

EPA considers a unit to have optimized use of an SNCR if NOx emissions rates are equal to or less than the mode 2 rate from the NEEDS database (Summer 2021). As described in Chapter 3 of EPA’s power sector IPM Modeling Documentation, these backstop NOx 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 NOx emission rates greater than their mode 2 rates in the 25-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 $2,000 per ton (2016$). 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 the proposed rule, 27 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 EPA Power Sector Modeling Platform v.6.20 Summer 2021 Reference Case, which lists state-of-the-art combustion control configurations based on unit

[23] For details on the derivation of this standard, please see preamble Section VII.B.1.

firing type. This allowed EPA to identify units that would receive state-of-the-art combustion control upgrades in IPM. EPA then followed the procedure in the EGU NO_X Mitigation Strategies Proposed Rule TSD to calculate each of these unit's new NO_X emission rate. These upgrades were assumed to occur 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 the proposed rule, 23 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 2023-42 fully captures the cost of any incremental controls under the proposed rule.

The EGU NO_X mitigation strategies that are assumed to operate or are available to reduce NO_X 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_X Mitigation Strategies Proposed Rule TSD.

Under the proposed rule 32 GW of SCR installations are projected. Under the more stringent alternative 54 GW of SCR installations are projected. Under the less stringent alternative 31 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 2023-42 fully captures the cost of any incremental controls under the proposed rule. Under the proposed rule an incremental 18 GW of coal (63 units) and 4 GW of oil/gas (13 units) retirements are projected by 2030. Under the more stringent alternative 20 GW of coal and 7 GW of oil/gas retirements are projected by 2030. Under the less stringent alternative 13 GW of coal and 4 GW of oil/gas retirements are projected by 2030. The associated costs of retirement are fully captured within the total costs of the proposed rule presented in the RIA.

In addition to the limitation on ozone season NO_X emissions required by the EGU emissions budgets for the 25 states and the backstop rate limits, there are four important features of the allowance trading program represented in the model that may influence the level and location of NO_X emissions from affected EGUs, including: the ability of affected EGUs to buy and sell NO_X ozone season allowances from one another for compliance purposes; the ability of affected EGUs to bank NO_X ozone season allowances for future use; the effect of limits on the total ozone season NO_X emissions from affected EGUs in each state required by the assurance provisions; and the treatment of banked pre-2023 vintage NO_X ozone season allowances issued under the Revised CSAPR Update now being revised under this proposed 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 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_X emissions across affected EGUs is generally governed by this cost-minimizing behavior in the analysis. The total ozone season NO_X emissions from affected EGUs in this analysis are limited to the amount allowed by the sum of the NO_X budgets across the 25 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_X 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 10.5 percent of the sum of the state emissions budgets for the current control period. Affected EGUs are expected to bank NO_X 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 proposed rule allows pre-2023 vintage NO_X ozone season allowances to be used for compliance with this proposed rule. The sources that would be participants in a revised Group 3 Trading Program under this proposal 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_X trading program. As described in Section VII.B.11 of the preamble, EPA is proposing transitional provisions that differ across the sets of potentially affected sources based on the sources' different starting points. Based on EPA's expectation of the size of the NO_X allowance bank after the one-time conversion carried out pursuant to the terms of this proposed rule, the treatment of these banked allowances is represented in the modeling as an additional 22,226 tons of NO_X allowances, the equivalent of half 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 proposed FIP for the 2015 ozone NAAQS and the more and less stringent alternatives.

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_X ozone season allowances, the assurance provisions limit the amount of seasonal NO_X emissions by affected EGUs in each of the 25 states. The assurance level limits affected EGU emissions over an ozone season to the state's NO_X 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 VII.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 VII.B.5 of the preamble also explains how 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_X emissions that may be emitted by affected EGUs in each state, and thus the modeling does not permit affected EGUs to emit beyond the assurance levels and thus incur penalties.

4.3.3 Methodology for Estimating Compliance Costs

This section describes EPA's approach to quantify estimated compliance costs 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_X 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,[24] and for installing or upgrading NO_X combustion controls, were estimated outside of the model. The costs for these three NO_X mitigation strategies are calculated based on IPM

[24] This includes optimizing the performance of SCRs that were not operating.

emissions projections and use the same NO_X 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_X mitigation strategies.

The following steps summarize EPA's methodology for estimating the component of compliance costs that are calculated outside of the model for the proposed rule alternative in 2023. Similar calculations are performed for every year in the forecast horizon[25]:

(1) In the model projections, identify all EGUs in the 25 states that can adopt the following NO_X 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_X reductions that are attributable to each of these strategies:

- Fully operating existing SCRs at coal steam units: 2,090 tons
- Fully operating existing SCRs at oil/gas steam, combined cycle, and combustion turbine units: 1,526 tons
- Fully operating existing SNCRs: 341 tons
- Installing state-of-the-art combustion controls: 2,056 tons

(3) Estimate the average cost (in 2016$) associated with each of these strategies:[26]

- Fully operating existing SCRs at coal steam units: $1,800/ton
- Fully operating existing SCRs at oil/gas steam, combined cycle, and combustion turbine units: $900/ton
- Fully operating existing SNCRs: $2,000/ton
- Installing state-of-the-art combustion controls: $1,600/ton

[25] For more information on the derivation of costs and useful life of combustion controls, please see EGU NO_X Mitigation Strategies Proposed Rule TSD.
[26] See EGU NO_X 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.

(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 proposed rule alternative in 2023.

Table 4-5. Summary of Methodology for Calculating Compliance Costs Estimated Outside of IPM for Proposed FIP for the 2015 Ozone NAAQS, 2023 (2016$)

NO_X Mitigation Strategy	NO_X Ozone Season Emissions (tons)	Average Cost ($/ton)	Total Cost ($MM)
Optimize existing SCRs at coal steam units	2,090	1,800	3.8
Optimize existing SCRs at oil/gas, combined cycle, and combustion turbine units	1,526	900	1.4
Optimize existing SNCRs	361	2,000	0.72
Installing state- of-the-art combustion controls	2,056	1,600	3.3

EPA exogenously updated the emissions rates for the identified EGUs within the 25 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. Unit level emission rate constraints were also imposed on affected uncontrolled units as outlined in Table 4-2 which forced units to choose to either retrofit or retire in a given year.

The change in the reported power system production cost between the proposed 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 Analytical Framework for Emission Reduction Assessment for Non-EGUs

The number of different industries and emissions unit categories and types, as well as the total number of emissions units that comprise the non-EGUs makes it challenging to define a method to identify appropriate control technologies, measures, or strategies and resulting impactful emissions reductions. The Agency incorporated air quality information as a first step in an analytical framework to help determine potentially impactful industries to focus on for further assessing potential controls, emission reduction potential, air quality improvements, and costs. Given the timing of this proposal, we developed the analytical framework using inputs from the air quality modeling for the Revised CSAPR Update (RCU) for 2023, as well as the projected 2023 annual emissions inventory that was used for the air quality modeling for this FIP proposal. Additional information on the analytical framework is presented in the non-EGU screening assessment available in the docket.

Using the RCU modeling for 2023, we identified upwind states linked to downwind nonattainment or maintenance receptors using the 1% of the NAAQS threshold criterion, which is 0.7 ppb (1% of a 70 ppb NAAQS). In 2023 there were 27 linked states for the 2015 NAAQS: Alabama, Arkansas, California, Delaware, Iowa, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Missouri, Mississippi, New Jersey, New York, Nevada, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, Wisconsin, West Virginia, and Wyoming.

To analyze non-EGU emissions units, we aggregated the underlying projected 2023 emissions inventory data into industries defined by 4-digit NAICS. Then for linked states, we followed the 2-step process below:

1. Step 1 -- We identified industries whose potentially controllable emissions are estimated, by applying the analytical framework, to have the greatest ppb impact on downwind air quality, and

2. Step 2 – We determined which of the most impactful industries and emissions units had the most emissions reductions that would make meaningful air quality improvements at the downwind receptors at a marginal cost threshold we determined using underlying control device efficiency and cost information.

To estimate the contributions by industry, defined by 4-digit NAICS, at each downwind receptor we used the 2023 state-receptor specific RCU ppb/ton values and the RCU calibration factors used in the air quality assessment tool (AQAT) for control analyses in 2023.[27] We focused on assessing emissions units that emit >100 tpy of NO_X. By limiting the focus to potentially controllable emissions, well-controlled sources that still emit > 100 tpy are excluded. Instead, the focus is on uncontrolled sources or sources that could be better controlled at a reasonable cost. As a result, reductions from any industry identified by this process are more likely to be achievable and to lead to air quality improvements.

Based on the industry contribution data, we prepared a summary with the estimated total, maximum, and average contributions from each industry and the number of receptors with contributions >= 0.01 ppb. We evaluated this information to identify breakpoints in the data. These breakpoints were then used to determine which industries to identify the most impactful industries to focus on for the next steps in the analysis.

A review of the contribution data indicated that we should focus the assessment of NO_X reduction potential and cost primarily on four industries. These industries each (1) have a maximum contribution to any one receptor of >0.10 ppb AND (2) contribute >= 0.01 ppb to at least 10 receptors. We refer to these four industries identified below as comprising “Tier 1”.

- Pipeline Transportation of Natural Gas
- Cement and Concrete Product Manufacturing
- Iron and Steel Mills and Ferroalloy Manufacturing
- Glass and Glass Product Manufacturing

In addition, the contribution data suggests that we should include five additional industries as a second tier in the assessment. These industries each either have (1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors. We refer to these five industries identified below as comprising “Tier 2”.

[27] The calibration factors are receptor-specific factors. For the RCU, the calibration factors were generated using 2016 base case and 2023 base case air quality model runs. These receptor-level ppb/ton factors are discussed in the Ozone Transport Policy Analysis Final Rule TSD found here: https://www.epa.gov/sites/default/files/2021-03/documents/ozone_transport_policy_analysis_final_rule_tsd_0.pdf.

- Basic Chemical Manufacturing
- Petroleum and Coal Products Manufacturing
- Metal Ore Mining
- Lime and Gypsum Product Manufacturing
- Pulp, Paper, and Paperboard Mills

For additional discussion of the contribution information, see Appendix A of the non-EGU screening assessment.

Next, to identify an annual cost threshold for evaluating potential emissions reductions in the Tier 1 and Tier 2 industries, the EPA used CoST, the CMDB, and the projected 2023 emissions inventory to prepare a listing of potential control measures, and their costs, applied to non-EGU emissions units in the projected 2023 emissions inventory. Using this data, we plotted curves for Tier 1 industries, Tier 2 industries, Tier 1 and 2 industries, and all industries at $500 per ton increments in the cost per ton threshold using known controls.[28] Figure 4-1 shows that there is a “knee in the curve” at approximately $7,500 per ton (2016$). We used this marginal cost threshold to further assess potential control strategies, estimated emissions reductions, air quality improvements, and costs from the potentially impactful industries. Note that controls and related emissions reductions are available at several estimated cost levels up to the $7,500 per ton threshold. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

[28] Known controls are well-demonstrated control devices and methods that are currently used in practice in many industries. Known controls do not include cutting edge or emerging pollution control technologies. They also do not include reductions in operations, changes in processes, or changing inputs such as fuels. Costs reflect capital and variable costs of installing and operating controls. The costs reflect annual costs of operating controls.

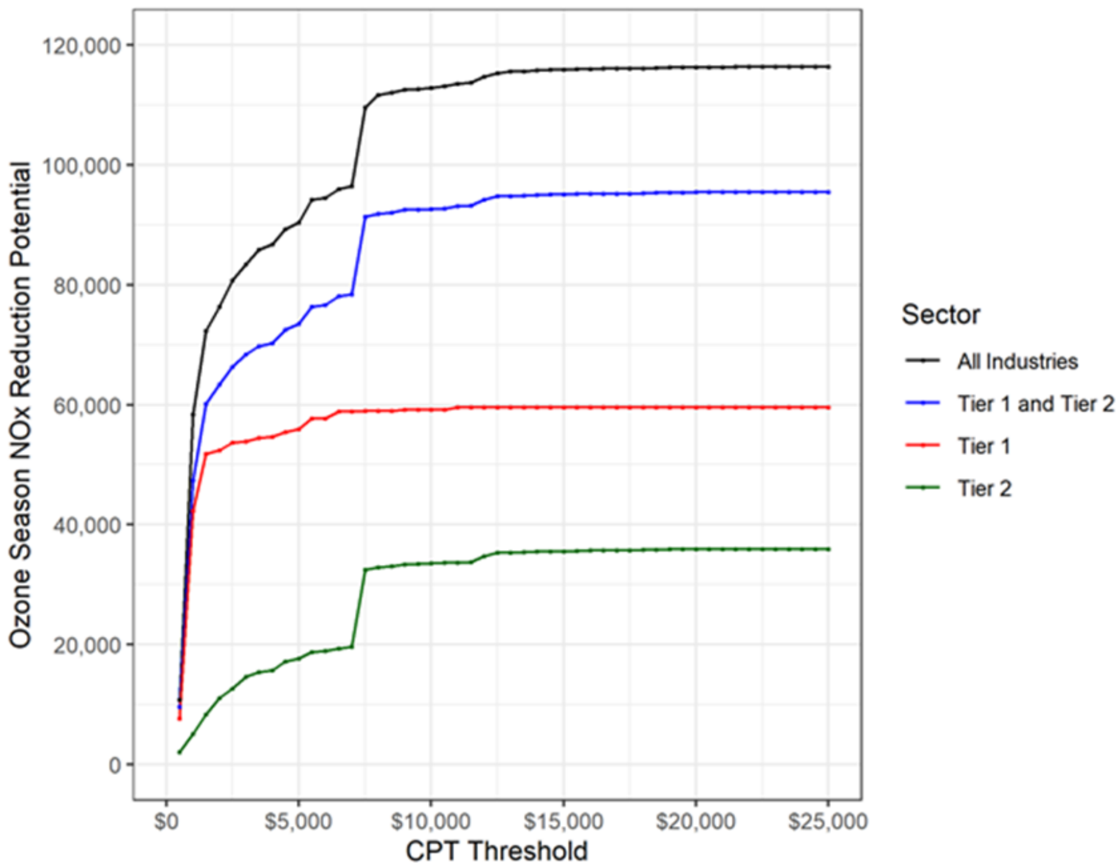

Figure 4-1. Ozone Season NO_X Reductions and Costs per Ton (CPT) for Tier 1, Tier 2 Industries, and All Industries (2016$)

Next, using the marginal cost threshold of $7,500 per ton, to estimate emissions reductions and costs the EPA processed the CoST run using the maximum emission reduction algorithm[29], with known controls. We identified controls for non-EGU emissions units in the Tier 1 and Tier 2 industries that cost up to $7,500 per ton. We then calculated air quality impacts associated with the estimated reductions for the 27 linked states in 2023 following the steps below.

1. We binned the estimated reductions by 4-digit NAICS code into the Tier 1 and Tier 2 industries.

[29] The maximum emission reduction algorithm assigns to each source the single measure (if a measure is available for the source) that provides the maximum reduction to the target pollutant. For more information, see the CoST User's Guide available at the following link: https://www.cmascenter.org/cost/documentation/3.7/CoST%20User's%20Guide/.

2. We used the 2023 state-receptor specific RCU ppb/ton values and the RCU calibration factors used in the AQAT for control analyses in 2023. We multiplied the estimated non-EGU reductions by the ppb/ton values and by the receptor-specific calibration factor to estimate the ppb impacts from these emissions reductions.

Next, because boilers represent the majority emissions unit in the Tier 2 industries for which there were controls that cost up to $7,500 per ton, we further targeted emissions reductions and air quality improvements in Tier 2 industries by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers. To identify potentially impactful boilers, using the projected 2023 emissions inventory in the linked upwind states we identified a universe of boilers with >100 tpy NO_X emissions that had any contributions at downwind receptors.[30,31,32] We refined the universe of boilers to a subset of impactful boilers by sequentially applying the three criteria below to each boiler. This approach is similar to the overall analytical framework and was tailored for application to individual boilers.[33]

- Criterion 1 -- Estimated maximum air quality contribution at an individual receptor of >=0.0025 ppb or estimated total contribution across downwind receptors of >=0.01 ppb.
- Criterion 2 -- Controls that cost up to $7,500 per ton.
- Criterion 3 -- Estimated maximum air quality improvement at an individual receptor of >=0.001 ppb.

4.5 Estimated Impacts of the Regulatory Control Alternatives

4.5.1 Emission Reduction Assessment for EGUs

As indicated in Chapter 1, the NO_X 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

[30] We used the 2023fj non-EGU point source inventory files.
[31] MD, MO, NV, and WY did not have boilers with >100 tpy NOx emissions.
[32] Some coal, oil, and gas-fired industrial boilers may have already installed combustion or post-combustion control equipment, such as SCR or SNCR, to meet the emission limits contained within EPA's NSPS located at 40 CFR 60 Subpart Db, which requires that some fossil fuel-fired units that commenced construction, modification, or reconstruction after June 19, 1984 meet various NOx emission limits based on factors such as unit type or heat rate. Additionally, industrial boilers located in ozone nonattainment areas or within the ozone transport region may have installed controls to meet emission limits adopted by states to meet NOx RACT requirements.
[33] For the impactful boiler assessment, the estimated air quality contributions and improvements were not based on modeling of individual emissions units or emissions source sectors. The air quality estimates were derived by using the 2023 state/receptor specific RCU ppb/ton values and the RCU calibration factors used in AQAT. The results indicate a level of precision not supported by the underlying air quality modeling. The results were intended to provide an indication of the relative impact across sources.

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_X emissions resulting from compliance with the evaluated regulatory control alternatives (i.e., emissions budgets) in the 25 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 proposed rule emissions budgets, and the more stringent alternative results in more NO_X emissions reductions.

Table 4-6. EGU Ozone Season NO_X Emissions and Emissions Changes (thousand tons) for the Baseline run and the Regulatory Control Alternatives from 2023 - 2042[34]

Ozone Season NOX (thousand tons)		Total Emissions				Change from Baseline run		
		Baseline run	Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative	Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative
2023	25 States	176	170	170	169	-6	-6	-6
	Other States	88	88	88	88	0	0	0
	Total	264	258	258	257	-6	-6	-7
2024	25 States	167	142	154	139	-25	-13	-28
	Other States	85	84	84	84	-1	-1	-1
	Total	252	226	238	223	-26	-14	-29
2025	25 States	158	114	137	109	-44	-20	-49
	Other States	82	80	81	80	-2	-1	-2
	Total	240	194	218	189	-46	-22	-51
2026	25 States	163	116	132	111	-47	-32	-53
	Other States	85	85	85	85	0	0	0
	Total	248	201	216	195	-47	-32	-53
2027	25 States	169	118	126	113	-51	-43	-56
	Other States	87	89	89	89	2	1	2
	Total	256	207	215	202	-49	-42	-54
2030	25 States	172	119	118	114	-53	-53	-57
	Other States	93	94	94	94	1	1	0
	Total	265	213	213	208	-52	-52	-57
2035	25 States	169	118	118	115	-50	-51	-54
	Other States	90	91	91	92	1	1	2
	Total	259	210	209	206	-49	-50	-52
2042	25 States	158	111	111	109	-47	-48	-49
	Other States	83	83	83	84	0	0	1
	Total	241	194	194	193	-47	-47	-48

[34] This analysis is limited to the geographically contiguous lower 48 states.

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 above. 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 proposed rule and less stringent alternative feature identical budgets, but the less stringent alternative assumes units that lack SCRs must retrofit or retire in the 2028 run year as compared to the 2025 run year in the proposed rule. Hence emissions reductions under the less stringent alternative are lower in the 2025 run year than the proposed rule but are similar thereafter. Similarly, the more stringent alternative features a larger universe of oil/gas steam units that must choose to retrofit or retire in the 2025 run year, driving higher abatement than the proposed rule. For details on the emission rate limits assumed in each of the regulatory control alternatives, please see Table 4-2.

The results of EPA's analysis show that, with respect to compliance with the EGU NO_X emission budgets in 2023, maximizing the use of existing operating SCRs provides the largest amount of ozone season NO_X emission reductions (58 percent, affecting 248 units), installing state-of-the-art combustion controls provides the next highest levels of ozone season reductions (33 percent, affecting 23 units), while optimizing existing SNCRs (6 percent, affecting 27 units) and generation shifting (4 percent) make up the remaining ozone season NO_X reductions. Based on this analysis of how EGUs are expected to comply with the proposed FIP for the 2015 ozone NAAQS, none of the Group 3 states are projected to hit their variability limits, nor withdraw a substantial additional number of allowances above the starting bank during the 2023-2042 period.[35]

In addition to the ozone season NO_X 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_X emissions, such as generation shifting. These other

[35] As shown in Table 4-6, in 2023 and 2025 seasonal NO_X 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.

emissions include the annual total changes in emissions of NOx, SO_2, CO_2, and direct $PM_{2.5}$ emissions changes. The emissions reductions are presented in Table 4-7.

Table 4-7. EGU Annual Emissions and Emissions Changes for NO_X, SO_2, $PM_{2.5}$, and CO_2 for the Regulatory Control Alternatives for 2023-2042

Annual NOx (thousand tons)		Total Emissions				Change from Baseline		
		Baseline run	Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative	Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative
2023	25 States	401	393	393	392	-8	-9	-9
	Other States	193	192	192	192	-1	-1	-1
	Total	594	584	584	584	-10	-10	-10
2024	25 States	373	333	354	330	-40	-20	-43
	Other States	186	184	184	184	-2	-2	-2
	Total	559	518	538	514	-42	-22	-45
2025	25 States	346	274	315	268	-71	-31	-78
	Other States	179	177	176	177	-2	-2	-2
	Total	524	451	491	444	-73	-33	-80
2026	25 States	366	285	311	278	-81	-55	-88
	Other States	186	186	186	186	0	0	0
	Total	552	471	497	464	-81	-55	-87
2027	25 States	386	295	307	288	-91	-78	-98
	Other States	193	196	195	196	3	2	3
	Total	579	491	503	484	-88	-76	-95
2030	25 States	399	301	299	297	-97	-100	-102
	Other States	205	207	207	207	2	2	2
	Total	604	508	506	504	-96	-98	-100
2035	25 States	394	302	299	298	-92	-95	-96
	Other States	199	201	201	201	2	2	3
	Total	592	502	499	499	-90	-93	-93
2042	25 States	340	268	264	267	-72	-76	-73
	Other States	175	177	176	177	1	1	2
	Total	515	445	440	444	-70	-75	-71
Annual SO_2		**Total Emissions**				**Change from Baseline**		
(thousand tons)		**Baseline run**	**Proposed Rule**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Proposed Rule**	**Less-Stringent Alternative**	**More-Stringent Alternative**
2023	25 States	483	483	483	482	1	0	-1
	Other States	149	148	148	148	-1	-1	-1

	Total	631	631	631	630	0	-1	-2
2024	25 States	439	399	420	397	-40	-19	-42
	Other States	138	137	137	137	-1	-1	-1
	Total	578	536	558	535	-42	-20	-43
2025	25 States	395	314	358	313	-81	-38	-83
	Other States	128	127	126	127	-2	-2	-1
	Total	524	441	484	440	-83	-39	-84
2026	25 States	446	339	369	337	-106	-77	-108
	Other States	137	137	137	137	0	0	1
	Total	583	476	506	475	-106	-76	-108
2027	25 States	496	365	380	362	-131	-116	-134
	Other States	145	147	148	147	2	2	2
	Total	641	512	528	510	-129	-113	-131
2030	25 States	551	446	449	446	-105	-101	-105
	Other States	159	160	160	160	1	1	1
	Total	710	605	609	606	-104	-100	-103
2035	25 States	555	467	470	465	-89	-85	-91
	Other States	164	156	156	157	-8	-7	-7
	Total	719	623	626	621	-96	-93	-98
2042	25 States	515	460	464	461	-56	-51	-55
	Other States	149	150	151	150	1	2	1
	Total	664	610	615	611	-54	-50	-54

Annual CO_2		**Total Emissions**				**Change from Baseline**		
(million metric tonnes)		**Baseline run**	**Proposed Rule**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Proposed Rule**	**Less-Stringent Alternative**	**More-Stringent Alternative**
2023	25 States	902	902	902	902	0	0	0
	Other States	417	416	416	416	-1	-1	-1
	Total	1319	1319	1319	1318	0	0	0
2024	25 States	856	838	847	837	-18	-9	-19
	Other States	411	411	410	411	0	-1	0
	Total	1267	1248	1257	1247	-18	-10	-19
2025	25 States	810	773	791	771	-36	-18	-38
	Other States	405	405	404	405	0	-1	0
	Total	1215	1178	1196	1176	-37	-19	-38
2026	25 States	844	801	816	799	-43	-29	-45
	Other States	416	419	418	419	3	2	3
	Total	1260	1220	1234	1218	-40	-26	-42
2027	25 States	879	830	840	828	-49	-39	-52
	Other States	427	433	432	432	6	5	6

	Total	1306	1263	1272	1260	-43	-34	-46
2030	25 States	910	857	861	856	-53	-49	-54
	Other States	438	442	441	443	3	3	4
	Total	1348	1298	1302	1298	-50	-45	-50
2035	25 States	926	886	887	885	-40	-39	-41
	Other States	443	445	446	446	2	3	3
	Total	1369	1331	1333	1331	-38	-36	-38
2042	25 States	886	862	864	862	-25	-23	-25
	Other States	422	422	422	423	0	0	1
	Total	1308	1284	1285	1284	-25	-23	-24

Annual $PM_{2.5}$ (thousand tons)		Total Emissions				Change from Baseline		
		Baseline run	**Proposed Rule**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Proposed Rule**	**Less-Stringent Alternative**	**More-Stringent Alternative**
2023	25 States	66	66	66	66	0	0	0
	Other States	32	32	32	32	0	0	0
	Total	98	98	98	98	0	0	0
2024	25 States	63	59	62	59	-4	-1	-4
	Other States	32	31	31	31	0	0	0
	Total	95	91	94	91	-4	-1	-4
2025	25 States	61	52	59	52	-9	-2	-9
	Other States	31	31	31	31	0	0	0
	Total	92	83	90	83	-9	-2	-9
2026	25 States	63	54	58	54	-9	-5	-9
	Other States	32	32	32	32	0	0	0
	Total	95	86	90	86	-9	-5	-9
2027	25 States	65	55	58	55	-10	-8	-10
	Other States	33	34	34	34	0	0	0
	Total	99	89	91	89	-10	-7	-10
2030	25 States	66	56	56	57	-9	-10	-9
	Other States	35	35	35	35	0	0	1
	Total	100	91	91	92	-9	-9	-9
2035	25 States	69	58	57	59	-11	-12	-11
	Other States	35	35	36	36	0	0	0
	Total	104	94	93	94	-11	-12	-10
2042	25 States	67	59	58	59	-8	-9	-8
	Other States	34	34	34	34	0	0	0
	Total	101	93	92	93	-8	-9	-8

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. Since the proposed 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

	Proposed Rule	More-Stringent Alternative	Less-Stringent Alternative
2023-2027 (Annualized)	$690	$1,076	$5
2023-2042 (Annualized)	$1,204	$1,624	$1,104
2023 (Annual)	($209)	($178)	($173)
2024 (Annual)	$707	$1,180	($406)
2025 (Annual)	$707	$1,180	($406)
2026 (Annual)	$707	$1,180	($406)
2027 (Annual)	$1,544	$1,983	$1,540
2030 (Annual)	$1,235	$1,740	$1,200
2035 (Annual)	$1,729	$2,335	$1,596
2042 (Annual)	$910	$1,001	$1,757

"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.[36] This does not include compliance costs beyond 2027. "2023-2042 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2023 through 2042 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2042. "2023 (Annual)" through "2042 (Annual)" costs reflect annual estimates in each of those years.[37]

There are several notable aspects of the results presented in Table 4-8. The most notable result in Table 4-8 is that the estimated annual compliance costs for the less stringent alternative is negative (i.e., a cost reduction) in 2023 through 2026, although this regulatory control alternative reduces NO_X emissions by 40 thousand tons as shown in Table 4-7. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given the

[36] 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. Tables ES-19 and 8-4 report the NPV of the annual stream of costs from 2023-2042 using 3% and 7% consistent with OMB guidance.

[37] Cost estimates include financing charges on capital expenditures that would reflect a transfer and would not typically be considered part of total social costs.

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.[38] For example, with the assumption of perfect foresight it is possible that on a national basis within the model the least-cost compliance strategy may be to delay a new investment or retirement that was projected to occur sooner in the baseline run. Such a delay could result in a lowering of annual cost in an early time period and increase it in later time periods.[39] The less-stringent alternative is designed to impose unit-level emission rates in the 2028 run year as compared to the 2025 run year as under the proposed rule and the more stringent alternative. This results in delayed retrofit and retirement at facilities covered by those rate limits, which in turn leads to negative total cost point estimates in 2023 through 2026. Under the proposed 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. Generation shifting costs are negative in 2023, but positive thereafter. The result is that the costs in 2023 are lower than costs thereafter. Projected costs for the illustrative proposed rule peak in 2035 at $1.7 billion (2016$) and annualized costs for the 2023-2042 period are $1.2 billion (2016$). To put these costs into context, the incremental 2035 projected cost constitutes 1.2 percent of total projected baseline system production costs.

Under the more stringent alternative, while 2023 includes the same set of controls as under the proposed FIP for the 2015 ozone NAAQS, a larger number of non-SCR controlled Oil/Gas steam units are subject to backstop emission rates that force units to either retrofit or retire. This, combined with more stringent state budgets driving generation shifting costs positive in every year, results in costs that grow over the 2024 - 2035 period.

In addition to evaluating annual compliance cost impacts, 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 levelized

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[38] For more information, please see Chapter 2 of the IPM documentation.
[39] As a sensitivity, EPA re-calculated costs assuming annual costs cannot be negative. This resulted in annualized 2023-42 costs under the proposed rule increasing from $1,204 million to $1,219 million (1.3%), and did not change the conclusions of this RIA.

annual cost associated with compliance with each regulatory control alternative.[40] For this analysis we first calculated the NPV of the stream of costs from 2023 through 2027[41] using a 3.76 percent discount rate. EPA typically uses a 3 and a 7 percent discount rate to discount future year social benefits and social costs in regulatory impact analyses (USEPA, 2010). 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).[42] 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.[43] The same approach was used to develop the annualized cost estimates for the 2023-2042 timeframe. Additionally, note that the 2023-2027 and 2023-2042 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 proposed FIP for the 2015 ozone NAAQS is expected to result in significant NO_X emissions reductions and 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, capacity by fuel type, and retail electricity prices for the 2023 and 2025 IPM model run years.

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[40] 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.
[41] 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.
[42] 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%."
[43] The PMT() function in Microsoft Excel 2013 is used to calculate the level annualized cost from the estimated NPV.

Table 4-9 and Table 4-10 present the percentage changes in national coal and natural gas usage by EGUs in the 2023 and 2025 run years. These fuel use estimates reflect a modest shift to natural gas and renewables from coal in 2023 as a result of tightening budgets. In the 2025 run year, coal consumption reductions under the proposed rule and the more stringent scenario 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 4-11. To put these reductions into context, under the Baseline, coal consumption is projected to decrease from 64 million tons in 2023 to 48 million tons in 2025 (13 percent annually), whereas under the proposed rule coal consumption is projected to decrease from 64 million tons in 2023 to 44 million tons in 2025 (16 percent annually). Between 2015 and 2020, annual coal consumption in the electric power sector fell between 8 and 19 percent annually.[44]

Table 4-9. 2023 and 2025 Projected U.S. Power Sector Coal Use for the Baseline and the Regulatory Control Alternatives

		Million Tons				Percent Change from Baseline		
	Year	**Baseline**	**Proposed Rule**	**Less-Stringent Alt.**	**More-Stringent Alt.**	**Proposed Rule**	**Less-Stringent Alt.**	**More-Stringent Alt.**
Appalachia	2023	64	64	64	64	0.5%	0.7%	0.7%
Interior		60	59	59	59	-0.9%	-0.8%	-1.2%
Waste Coal		4	4	4	4	0.0%	0.0%	0.0%
West		180	180	179	180	0.0%	0.0%	0.0%
Total		308	308	308	308	0.0%	-0.1%	-0.1%
Appalachia	2025	48	44	47	45	-8.3%	-4.0%	-7.5%
Interior		44	45	45	43	1.0%	0.7%	-1.8%
Waste Coal		4	4	4	4	0.0%	0.0%	0.0%
West		151	136	144	136	-10.2%	-4.3%	-10.1%
Total		248	229	240	228	-7.7%	-3.3%	-7.9%

[44] US EIA Monthly Energy Review, Table 6.2, January 2022.

Table 4-10. 2023 and 2025 Projected U.S. Power Sector Natural Gas Use for the Baseline and the Regulatory Control Alternatives

Trillion Cubic Feet					Percent Change from Baseline		
Year	Baseline	Proposed Rule	Less-Stringent Alt.	More-Stringent Alt.	Proposed Rule	Less-Stringent Alt.	More-Stringent Alt.
2023	12	12	12	12	0.05%	0.04%	0.04%
2025	12	12	12	12	0.20%	-0.77%	0.25%

Table 4-11 and Table 4-12 present the projected coal and natural gas prices in 2023 and 2025, 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 and 2025 Projected Minemouth and Power Sector Delivered Coal Price (2016$) for the Baseline and the Regulatory Control Alternatives

		$/MMBtu				Percent Change from Baseline		
		Baseline	Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative	Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative
Minemouth	2023	1.13	1.13	1.13	1.13	-0.72%	-0.63%	-0.79%
Delivered	2023	1.59	1.58	1.58	1.58	-0.52%	-0.47%	-0.58%
Minemouth	2025	1.17	1.17	1.16	1.17	0.30%	-0.68%	0.10%
Delivered	2025	1.57	1.53	1.55	1.53	-2.51%	-1.33%	-2.67%

Table 4-12. 2023 and 2025 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	Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative	Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative
Henry Hub	2023	2.40	2.39	2.39	2.39	-0.55%	-0.46%	-0.45%
Delivered	2023	2.50	2.49	2.49	2.49	-0.53%	-0.43%	-0.41%
Henry Hub	2025	2.22	2.22	2.22	2.22	0.00%	-0.01%	0.00%
Delivered	2025	2.31	2.31	2.31	2.31	0.00%	0.03%	0.04%

Table 4-13 presents the projected percentage changes in the amount of electricity generation in 2023 and 2025 by fuel type. Consistent with the fuel use projections and emissions trends above, EPA projects an overall shift from coal to gas and renewables. The projected impact in 2025 larger, reflecting the tightening budgets.

Table 4-13. 2023 and 2025 Projected U.S. Generation by Fuel Type for the Baseline and the Regulatory Control Alternatives

		Generation (TWh)				Percent Change from Baseline		
	Year	**Baseline**	**Proposed Rule**	**Less-Stringent Alternative**	**More-Stringent Alternative**	**Proposed Rule**	**Less-Stringent Alternative**	**More-Stringent Alternative**
Coal	2023	596	595	595	595	-0.10%	-0.09%	-0.12%
Natural Gas		1,657	1,658	1,658	1,659	0.03%	0.03%	0.09%
Nuclear		741	741	741	741	0.00%	0.00%	0.00%
Hydro		294	294	294	294	-0.01%	0.00%	-0.02%
Non-Hydro RE		745	745	745	745	0.00%	0.00%	0.00%
Oil/Gas Steam		51	51	51	51	0.47%	0.22%	-1.05%
Other		36	36	36	36	0.00%	0.00%	0.00%
Grand Total		4,135	4,135	4,135	4,135	0.00%	0.00%	0.00%
Coal	2025	485	447	469	445	-7.77%	-3.25%	-8.22%
Natural Gas		1,660	1,663	1,655	1,665	0.15%	-0.32%	0.30%
Nuclear		689	689	689	689	0.00%	0.00%	0.00%
Hydro		293	293	293	293	0.19%	0.08%	0.17%
Non-Hydro RE		949	983	975	983	3.64%	2.77%	3.64%
Oil/Gas Steam		58	58	52	58	0.31%	-9.36%	-0.18%
Other		36	36	36	36	0.00%	0.00%	0.00%
Grand Total		4,185	4,186	4,186	4,185	0.02%	0.01%	0.01%

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 and 2025 by primary fuel type. As explained above, none of the regulatory control alternatives are expected to have a net impact on overall capacity by primary fuel type in 2023, and the model was specified accordingly. By 2030 the proposed rule is projected to result in an additional 18 GW of coal and 4 GW of oil/gas steam retirements nationwide relative to the Baseline run, constituting a reduction of 13 percent of national coal capacity and 2 percent of oil/gas steam capacity, partially reflecting some earlier retirement under the proposed rule relative to the Baseline run. This is compared to an average recent historical retirement rate of 11 GW per year from 2015 – 2020 (https://www.eia.gov/todayinenergy/detail.php?id=50838).

Additionally, the proposed rule is projected to incentivize an incremental 18 GW of SCR retrofit at coal plants and 14 GW of SCR retrofit at oil/gas steam plants. The proposed rule is also projected to result in an incremental 14 GW of renewable capacity additions in 2025 (consistent primarily 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 proposed rule scenarios.

Table 4-14. 2023 and 2025 Projected U.S. Capacity by Fuel Type for the Baseline run and the Regulatory Control Alternatives

		Capacity (GW)				Percent Change from Baseline run		
	Year	**Baseline run**	**Proposed Rule**	**Less-Stringent Alt**	**More-Stringent Alt**	**Proposed Rule**	**Less-Stringent Alt**	**More-Stringent Alt**
Coal	2023	164	164	164	164	0%	0%	0%
Natural Gas		429	429	429	429	0%	0%	0%
Nuclear		93	93	93	93	0%	0%	0%
Hydro		102	102	102	102	0%	0%	0%
Non-Hydro RE		234	234	234	234	0%	0%	0%
Oil/Gas Steam		63	63	63	63	0%	0%	0%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,104	1,104	1,104	1,104	0%	0%	0%
Coal	2025	157	134	144	132	-15%	-8%	-16%
Natural Gas		430	432	431	433	0%	0%	1%
Nuclear		86	86	86	86	0%	0%	0%
Hydro		102	102	102	102	0%	0%	0%
Non-Hydro RE		281	295	291	295	5%	4%	5%
Oil/Gas Steam		64	65	60	63	2%	-6%	-2%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,140	1,134	1,135	1,131	-1%	0%	-1%

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind

EPA estimated the change in the retail price of electricity (2016$) using the Retail Price Model (RPM).[45] The RPM was developed by ICF for 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 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 (shown in Figure 4-2) in the electricity market module of the National Energy Modeling System (NEMS).[46]

Table 4-15 and Table 4-16 present the projected percentage changes in the retail price of electricity for the three regulatory control alternatives in 2023 and 2025, 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, EPA estimates that this proposed rule will result in a 1 percent increase in national average retail electricity price, or by about 1.02 mills/kWh.

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		
Region	**Baseline**	**Proposed Rule**	**Less-Stringent Alt.**	**More-Stringent Alt.**	**Proposed Rule**	**Less-Stringent Alt.**	**More-Stringent Alt.**
TRE	71	69	69	69	-3%	-3%	-3%
FRCC	91	91	91	91	0%	0%	0%
MISW	95	95	95	95	0%	0%	0%
MISC	85	84	84	84	-1%	-1%	-1%
MISE	92	92	91	92	0%	0%	0%
MISS	73	73	73	73	0%	0%	0%
ISNE	130	130	130	130	0%	0%	0%
NYCW	533	536	537	501	1%	1%	-6%
NYUP	114	114	114	114	0%	0%	0%
PJME	154	157	157	153	2%	1%	-1%
PJMW	89	88	88	88	-1%	-1%	-1%
PJMC	85	83	83	83	-2%	-2%	-2%
PJMD	69	67	67	67	-2%	-2%	-2%

[45] See documentation available at: https://www.epa.gov/airmarkets/retail-price-model
[46] See documentation available at: https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/m068(2020).pdf

SRCA	91	91	91	91	0%	0%	0%
SRSE	91	91	91	91	0%	0%	0%
SRCE	67	67	67	67	0%	0%	0%
SPPS	74	73	73	73	0%	0%	0%
SPPC	100	100	100	100	0%	0%	0%
SPPN	65	65	65	65	0%	0%	0%
SRSG	96	96	96	96	0%	0%	0%
CANO	140	140	140	140	0%	0%	0%
CASO	171	171	171	171	0%	0%	0%
NWPP	70	70	70	70	0%	0%	0%
RMRG	90	90	90	90	0%	0%	0%
BASN	84	84	84	84	0%	0%	0%
NATIONAL	103	103	103	102	0%	0%	-1%

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		
Region	**Baseline**	**Proposed Rule**	**Less-Stringent Alt.**	**More-Stringent Alt.**	**Proposed Rule**	**Less-Stringent Alt.**	**More-Stringent Alt.**
TRE	66	68	66	68	3%	0%	3%
FRCC	89	89	89	89	0%	0%	0%
MISW	93	94	93	94	1%	0%	1%
MISC	83	86	84	86	3%	1%	3%
MISE	80	80	80	83	-1%	0%	3%
MISS	73	74	73	74	1%	0%	1%
ISNE	135	135	135	135	0%	0%	0%
NYCW	173	173	173	173	0%	0%	0%
NYUP	108	109	109	109	1%	1%	0%
PJME	94	94	93	94	0%	0%	1%
PJMW	83	86	85	89	5%	3%	8%
PJMC	74	81	78	86	9%	5%	15%
PJMD	62	66	65	69	6%	3%	10%
SRCA	89	89	89	89	0%	0%	0%
SRSE	89	89	89	89	-1%	-1%	-1%
SRCE	66	66	66	66	0%	0%	1%
SPPS	75	75	74	75	0%	-1%	1%
SPPC	99	100	99	100	1%	0%	1%
SPPN	64	63	63	63	-2%	-1%	-2%
SRSG	95	95	95	95	0%	0%	0%
CANO	147	147	147	147	0%	0%	0%

CASO	179	179	179	179	0%	0%	0%
NWPP	71	71	71	71	0%	0%	0%
RMRG	88	88	88	88	0%	0%	0%
BASN	84	85	83	85	1%	0%	1%
NATIONAL	90	91	91	92	1%	0%	2%

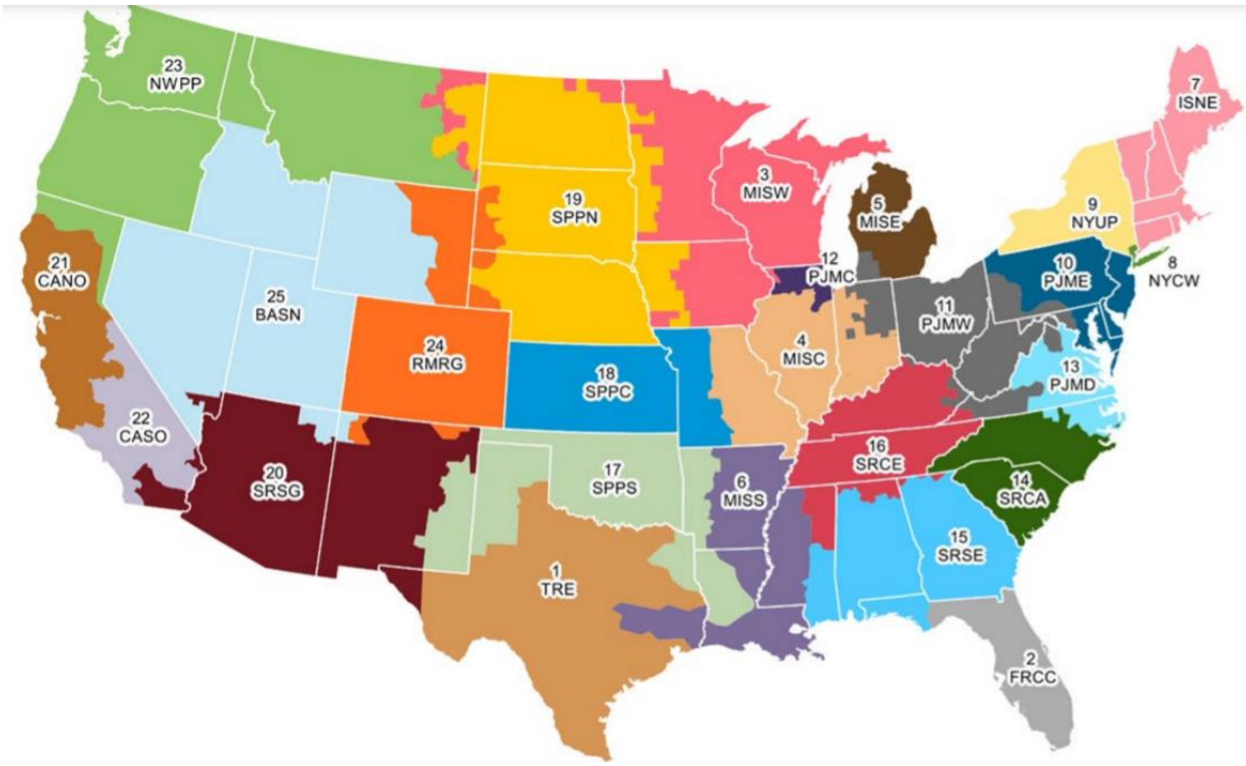

Figure 4-2. Electricity Market Module Regions
Source: EIA (http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf)

4.5.4 Emission Reduction and Compliance Cost Assessment for Non-EGUs from Screening Assessment for 2026

EPA determined that 2026 was the potential earliest date by which controls on non-EGU emissions units could be installed. EPA updated its analytical framework to the analytic year of 2026 by which EPA is proposing non-EGU controls be installed across the Tier 1 and Tier 2 industries and various emissions unit types. As such, we prepared a screening assessment for the year 2026 by generally applying the analytical framework detailed above. The screening assessment for 2026 is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully accounts for retrofit difficulty for the emissions units, potential controls, and related costs.

Specifically in the screening assessment for 2026, we:

- Retained the impactful industries identified in Tier 1 and Tier 2, the $7,500 cost per ton threshold, and the methodology for identifying impactful boilers,
- Modified the framework to address challenges associated with using the projected 2023 emissions inventory by using the 2019 emissions inventory[47], and
- Updated the air quality modeling data by using data for 2026.

We used CoST to identify emissions units, emissions reductions, and costs to include in a proposed FIP; however, CoST is designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. These estimates from CoST identify proxies for (1) non-EGU emissions units that have emission reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units.

To prepare the screening assessment for 2026, we applied the analytical framework detailed above. The assessment includes emissions units from the Tier 1 industries and impactful boilers from the Tier 2 industries. Using the latest air quality modeling for 2026, we identified upwind states linked to downwind nonattainment or maintenance receptors using the 1% of the NAAQS threshold criterion, or 0.7 ppb. In 2026 there are 23 linked states for the 2015 NAAQS: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Missouri, Mississippi, New Jersey, New York, Nevada, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, Wisconsin, West Virginia, and Wyoming.

We re-ran CoST with known controls, the CMDB, and the 2019 emissions inventory. The analysis assumes that the 2019 emissions from the emissions units will be the same in 2026 and later years. We specified CoST to allow replacing an existing control if a replacement control is estimated to be >10 percent more effective than the existing control. We did not replace an existing control if the 2019 emissions inventory indicated the presence of that control, even if the CMDB reflects a greater control efficiency for that control. Also, we removed six facilities from consideration because they are subject to an existing consent decree, are shut down, or will shut

[47] EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term emissions reductions. Also, see memorandum titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026*, available in the docket, for a discussion of the challenges associated with using the projected 2023 emissions inventory.

down by 2026. For additional detail on the six facilities removed, see Appendix B in the non-EGU screening assessment. Table 4-17 below summarizes the estimated reductions and annual total and average annual costs (2016$) for the proposal. The cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.[48] The proposed rule alternative includes 489 non-EGU emissions units.

Table 4-18 below summarizes, by industry, the number of emissions units, reductions, and costs for the proposal. Table 4-19 below summarizes the estimated reductions and annual total and average annual costs (2016$) for the less and more stringent alternatives.

Because the proposed 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 4-17 and Table 4-19. Note that some of the EGU controls are assumed to run year-round. Also, because the proposed FIP for the 2015 ozone NAAQS includes emissions limits, and the non-EGU screening assessment does not account for growth in the affected industries and capital turnover over time, the reductions are the same each year over the period from 2026 to 2042.

For additional 2026 screening assessment results -- including by industry and by state, estimated emissions reductions and costs -- see the non-EGU screening assessment.

Table 4-17. Annual Estimated Emissions Reductions for 2026-2042 (ozone season tons) and Annual Total Costs for the Proposed Rule

Proposed Alternative	Ozone Season NOx Emissions Reductions	Annual Total Cost (million 2016$) (Average Annual Cost/Ton)
Tier 1 Industries with Known Controls that Cost up to $7,500/ton	41,153	$356.6 ($3,610)

[48] EPA submitted an information collection request (ICR) to OMB associated with the proposed monitoring, calibrating, recordkeeping, reporting and testing activities required for non-EGU emissions units -- *ICR for the Proposed Rule, Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard: Transport Obligations for non-Electric Generating Units*, EPA ICR No. 2705.01. The ICR is summarized in Section XI.B.2 of the proposed rule preamble. The ICR includes estimated monitoring, recordkeeping, reporting, and testing costs of approximately $11.45 million per year for the first three years. These costs are not reflected in the cost estimates in Table 4-17 and Table 4-19.

Proposed Alternative	Ozone Season NOx Emissions Reductions	Annual Total Cost (million 2016$) (Average Annual Cost/Ton)
Impactful Boilers in Tier 2 Industries with Known Controls that Cost up to $7,500/ton	6,033	$54.2 ($3,744)
Totals	**47,186**	**$410.8**

Table 4-18. By Industry, Number and Type of Emissions Units and Total Estimated Emissions Reductions (ozone season tons)

		Number of Units by Type			Ozone Season Emission Reductions (tons) by Type of Unit		
Industry	**Region**	**Boilers**	**Internal Combustion Engines**	**Industrial Processes**	**Boilers**	**Internal Combustion Engines**	**Industrial Processes**
Glass and Glass Product Manufacturing	East	-	-	41	-	-	6,367
	West	-	-	3	-	-	299
Cement and Concrete Product Manufacturing	East	1	-	39	16	-	5,948
	West	-	-	8	-	-	2,128
Iron and Steel Mills and Ferroalloy Manufacturing	East	25	-	15	2,044	-	1,207
Pipeline Transportation of Natural Gas	East	-	296	-	-	22,390	-
	West	-	11	-	-	754	-
Basic Chemical Manufacturing	East	17	-	-	1,698	-	-
Petroleum and Coal Products Manufacturing	East	9	-	-	962	-	-
	West	1	-	-	68	-	-
Pulp, Paper, and Paperboard Mills	East	25	-	-	3,305	-	-

Blue highlights reflect western

Orange highlights reflect Tier 2 industries

Table 4-19. Annual Estimated Emissions Reductions for 2026-2042 (ozone season tons) and Annual Total Costs for the Less and More Stringent Alternatives

Alternative	Ozone Season NOx Emissions Reductions	Annual Total Cost (million 2016$) (Average Annual Cost/Ton)
Less Stringent Alternative – *Tier 1 Industries with Known Controls that Cost up to $7,500/ton*	41,153	$356.6 ($3,610)
More Stringent Alternative – *Tier 1 Industries with Known Controls that Cost up to $7,500/ton* <u>*and*</u> *All Boilers in Tier 2 Industries with Known Controls that Cost*	50,918	$445.1 ($3,642)

Alternative	Ozone Season NOx Emissions Reductions	Annual Total Cost (million 2016$) (Average Annual Cost/Ton)
up to $7,500/ton		

4.5.6 Total Emissions Reductions and Compliance Costs for EGUs and Non-EGUs

For years between 2023 and 2042, Table 4-20 below summarizes the total annual estimated emissions reductions and compliance costs for EGUs and non-EGUs for the proposed rule and the less and more stringent alternatives. Table 4-21 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 proposed rule 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 4-20. Total Annual Estimated NO_x Emissions Reductions (ozone season, thousand tons) and Compliance Costs (million 2016$), 2023-2042

		Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative	Proposed Rule	Less-Stringent Alternative	More-Stringent Alternative
		Emissions Reductions (ozone season, thousand tons)			Compliance Costs (million 2016$)		
2023	EGUs	6	6	7	(209)	(173)	(178)
	Non-EGUs	--	--	--	-	-	-
	Total	**6**	**6**	**7**	**(209)**	**(173)**	**(178)**
2026	EGUs	47	32	53	707	(406)	1,180
	Non-EGUs	47	41	51	411	357	445
	Total	**95**	**73**	**103**	**1,117**	**(49)**	**1,625**
2027	EGUs	49	42	54	1,544	1,540	1,983
	Non-EGUs	47	41	51	411	357	445
	Total	**96**	**83**	**105**	**1,955**	**1,896**	**2,428**
2030	EGUs	52	52	57	1,235	1,200	1,740
	Non-EGUs	47	41	51	411	357	445
	Total	**99**	**93**	**108**	**1,646**	**1,557**	**2,185**
2035	EGUs	49	50	52	1,729	1,596	2,335
	Non-EGUs	47	41	51	411	357	445
	Total	**96**	**91**	**103**	**2,139**	**1,953**	**2,780**
2042	EGUs	47	47	48	910	1,757	1,001
	Non-EGUs	47	41	51	411	357	445
	Total	**94**	**88**	**99**	**1,321**	**2,114**	**1,446**

Table 4-21. Total National Compliance Cost Estimates (millions of 2016$) for the Proposed Rule and the Less and More Stringent Alternatives

	Proposed Rule		Less Stringent Alternative		More Stringent Alternative	
	3 Percent	**7 Percent**	**3 Percent**	**7 Percent**	**3 Percent**	**7 Percent**
Present Value EGU 2023-2042	$17,000	$11,000	$16,000	$9,400	$23,000	$15,000
Present Value Non-EGU 2026-2042	$4,800	$3,100	$4,200	$2,700	$5,200	$3,300
Present Value Total 2023-2042	**$22,000**	**$14,000**	**$20,000**	**$12,000**	**$28,000**	**$18,000**
EGU Equivalent Annualized Value	$1,100	$1,000	$1,100	$890	$1,500	$1,400
Non-EGU Equivalent Annualized Value	$320	$290	$280	$250	$350	$310
Total Equivalent Annualized Value	**$1,500**	**$1,300**	**$1,300**	**$1,100**	**$1,900**	**$1,700**

Note: Values have been rounded to two significant figures

4.5.7 Impact of Emissions Reductions on Maintenance and Nonattainment Monitors

EPA evaluated whether reductions resulting from the selected control stringencies for EGUs in 2023 and 2026 combined with the emissions reductions expected for non-EGUs in 2026 can be anticipated to resolve any downwind nonattainment or maintenance problems. See Appendix 3B for additional discussion of the estimated improvements in downwind air quality for each of the regulatory control alternatives analyzed in this RIA, as well as data on average and maximum design value changes at downwind receptors.

4.6 Social Costs

As discussed in EPA's *Guidelines for Preparing Economic Analyses*, social costs are the total economic burden of a regulatory action (USEPA, 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 as a result of reallocating some resources towards pollution mitigation. Estimates of social costs may be compared to the social benefits expected as a result 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 proposed rule. Nonetheless, here we use total national compliance costs for EGUs and non-EGUs as a proxy for social costs. Table 4-20 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 proposed and more or less stringent regulatory control alternatives presented above are the change in expenditures by the electricity generating 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_X control strategies necessary to comply with the emissions budgets and the backstop emissions limits. The production cost changes included 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 proposed 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_X 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 4-20 are derived from engineering cost estimates, 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.

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 proposal 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, such as cement.

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 taken into account, 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.

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 reviewed concluded in 2020.[49] While EPA now has a peer reviewed CGE model for analyzing the potential economy-

[49] 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::

wide effects of regulations, we have not used the model in the RIA for this proposal due to the expedited proposed rulemaking timeline. However, EPA continues to be committed to the use of CGE models to evaluate the economy-wide effects of its regulations.

4.7 Limitations

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 changes, and other impacts of regulatory actions for EGUs. The annualized cost of the proposed rule for EGUs, as quantified here, is EPA's best assessment of the cost of implementing the proposal on the power sector. These costs are generated from rigorous economic modeling of changes in the power sector due to implementation of the proposed FIP for the 2015 ozone NAAQS.

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 proposal. To estimate these annualized costs, as discussed earlier in this chapter, 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 EPA's best estimate of the direct private compliance costs of the proposal.

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: Large increases in supply over the last few years, and relatively low prices, are represented in the analysis. 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 proposed rule.

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 scenarios similarly, and therefore the impact on the incremental projections (reflecting the potential costs/benefits of the illustrative policy scenario) would be more limited and are not likely to result in notable changes to the assessment of the proposed 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 policy scenario 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.

While the baseline includes modeling to capture the recently finalized 2020 effluent Limitation Guidelines (ELG), it does not incorporate 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 proposed 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.

As discussed in section 4.3.2, IPM v.6.20 does not have the capacity to endogenously determine whether or not to maximize the use of existing EGU post-combustion NO_X 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[50] 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.[51] 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[52] 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, EPA used estimated emissions reductions and costs from the non-EGU screening assessment in this RIA as a proxy for the least-cost compliance strategy for complying with the emissions limits proposed for the non-EGU industries. In the screening assessment, which is available in the docket for this proposed rulemaking, EPA used CoST to identify emissions units,

[50] Available at: https://www.federalregister.gov/documents/2021/08/10/2021-16582/revised-2023-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-standards
[51] Regulatory Impact Analysis available at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1012ONB.pdf
[52] 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

emissions reductions, and associated compliance costs; CoST is designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. The estimates from CoST identify proxy values for (1) non-EGU emissions units that have 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. The control cost estimates assume an average level of retrofit difficulty for control applications, and do not include monitoring, recordkeeping, reporting, or testing costs. This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. It is not possible to determine whether this approach leads to an over or underestimate of the costs, and consequent NOx and other pollutant emissions changes, benefits, and other impacts, including the effect on downwind receptors, of the proposed rule and the analyzed alternatives. This is because we did not directly evaluate the emissions reductions that would be achieved at the emissions units included in the proposal using their baseline emissions and emissions rates, their emission limits, and their likely compliance strategy. Also, we did not project the potential changes in the number of existing and new units resulting from industry growth or capital turnover, nor whether the emissions limitations would require further NOx emissions reductions at new units relative to what is required of them in the baseline.

4.8 References

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CHAPTER 5: BENEFITS

Overview

This proposed Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (FIP for the 2015 ozone NAAQS) is expected to reduce emissions of nitrogen oxides (NO_X) 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 proposed FIP for the 2015 ozone NAAQS is expected to reduce emissions of NO_X, which will in turn reduce concentrations of ground-level ozone and fine particles ($PM_{2.5}$); the proposed rule is also projected to reduce sulfur dioxide (SO_2), direct $PM_{2.5}$ emissions, carbon dioxide (CO_2) 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 $PM_{2.5}$ for each of three regulatory control alternatives described in prior chapters.[1] Though the proposed rule is likely to also yield positive benefits associated with reducing pollutants other than ozone and $PM_{2.5}$, 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 $PM_{2.5}$ from affected EGUs. This analysis uses both full-form and reduced-form techniques to quantify benefits. Both approaches rely on the same methods for quantifying the number and value of air pollution-attributable premature deaths and illnesses, which is described in the TSD for the Final Revised CSAPR Update for the 2008 Ozone NAAQS titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*. Methods used to estimate $PM_{2.5}$ benefits are described in the TSD

[1] 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.

titled *Estimating the Benefit per Ton of Reducing Directly-Emitted PM2.5, PM2.5 Precursors and Ozone Precursors from 21 Sectors*.

When estimating the value of improved air quality over a multi-year time horizon, the ozone analysis applies population growth and income growth projections for each future year through 2042 and estimates of 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 5-6 and 5-7 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 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_X emissions attributable to this proposal; this artifact may introduce uncertainty to the ozone analysis and is described below in Section 5.1.3. When estimating the value of improved air quality over a multi-year time horizon, the $PM_{2.5}$ analysis applies benefit per ton estimates from 2025 for 2023-2029 and 2030 for 2030-2042, which also introduces uncertainty.

Data, resource, and methodological limitations prevent EPA from monetizing health benefits of reducing direct exposure to NO_2 and SO_2, ecosystem effects and visibility impairment associated with these pollutants, ozone and $PM_{2.5}$, 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 proposed rule is expected to reduce ozone season and annual NO_X emissions. In the presence of sunlight, NO_X and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X 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_X, the proposed rule is also expected to reduce emissions of direct $PM_{2.5}$ and SO_2 throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects.

In this proposed FIP for the 2015 ozone NAAQS regulatory impact analysis (RIA), as discussed above, EPA uses both full-form and reduced-form techniques to quantify benefits of changes in $PM_{2.5}$ and ozone concentrations. In particular, both methods incorporate evidence reported in the most recent completed PM and Ozone Integrated Science Assessments (ISAs) and accounts 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 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 Final Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*.

The *Estimating $PM_{2.5}$- 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.[2]

As structured, the proposed rule would affect the distribution of ozone and $PM_{2.5}$ 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 $PM_{2.5}$-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 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 emissions control measures. As shown and described in Chapter

[2] The analysis was completed using BenMAP-CE version 1.5.8, which is a variant of the current publicly available version.

3, we project most levels of ozone to decrease, primarily in and around the 26 affected states.[3] The ozone-related benefit estimates are based on these modeled changes in summer season average ozone concentrations We also estimate benefits from EGU $PM_{2.5}$ emissions changes using a benefit per ton approach, which is described more fully in Sections 5.1.1.4 and 5.1.1.5. For non-EGU NO_X emissions changes., since the proposed FIP for the 2015 ozone NAAQS includes ozone season emissions limits for the non-EGU emissions units. As we do not know if all affected sources will run controls year-round or only during ozone season, we also provide an illustration of potential $PM_{2.5}$ benefits that could accrue from non-EGUs if the proposed controls are run year-round. These illustrative $PM_{2.5}$ benefits are not added to the total benefits for this proposal.

5.1.1 Health Impact Assessment for Ozone and $PM_{2.5}$

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 final Revised CSAPR Update, based on the 2019 and 2020 PM and ozone ISAs (U.S. EPA, 2020c).

Estimating the health benefits of reductions in $PM_{2.5}$ and $ozone_3$ 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 risk change, 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.[4] 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

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[3] In a small number of areas in the northwest, we project ozone to increase slightly compared to the baseline.
[4] 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.

quantify; (2) calculating counts of air pollution effects using a health impact function; (3) specifying the health impact function with concentration-response parameters drawn from the epidemiological literature.

5.1.1.1 Selecting Air Pollution Health Endpoints to Quantify

As a first step in quantifying ozone and $PM_{2.5}$-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 for Particulate Matter (PM ISA) (U.S. EPA 2019a). These two 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 classified 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 $PM_{2.5}$ 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 $PM_{2.5}$. A likely-to-be-causal relationship was determined between long-term $PM_{2.5}$ 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.

Table 5-1 reports the ozone and $PM_{2.5}$-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 5-9 below report other omitted health and environmental benefits expected from the emissions and effluent changes as a result of this proposal, such as health effects associated with NO_2 and SO_2, 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, benefit per ton values were used to estimate the benefits from changes in $PM_{2.5}$ concentrations from changes in NO_x, SO_2 and $PM_{2.5}$ emissions. For PM-related benefits for non-EGUs, due to uncertainty in whether affected sources will run controls year-round or only during ozone season, benefit per ton values were used to estimate the benefits from changes in NO_x emissions to illustrate the potential $PM_{2.5}$ benefits from non-EGUs if the proposed controls are run year-round. The illustrative non-EGU PM benefits estimates are not added to the total benefits for this proposal.

Consistent with economic theory, the WTP for reductions in exposure to environmental hazard 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 $PM_{2.5}$ or ozone and potential health endpoints from the ISAs that are developed for the NAAQS process as discussed above. The focus on categories 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.[5] All else equal, this approach may underestimate the benefits of $PM_{2.5}$ and ozone 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.[6] 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.

[5] This decision criterion for selecting health effects to quantify and monetize $PM_{2.5}$ and ozone 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.

[6] 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 $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD section 6.2.3).

Table 5-1. Health Effects of Ambient Ozone and $PM_{2.5}$

Category	Effect	Effect Quantified	Effect Monetized	More Information
Premature mortality from exposure to $PM_{2.5}$	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
Nonfatal morbidity from exposure to $PM_{2.5}$	Heart attacks (age > 18)	✓	✓[1]	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)	✓	✓[1]	PM ISA
	Stroke (ages 65-99)	✓	✓[1]	PM ISA
	Asthma onset (ages 0-17)	✓	✓	PM ISA
	Asthma symptoms/exacerbation (6-17)	✓	✓	PM ISA
	Lung cancer (ages 30-99)	✓	✓	PM ISA
	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[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[2]
	Other nervous system effects (e.g., autism, cognitive decline, dementia)	—	—	PM ISA[2]
	Metabolic effects (e.g., diabetes)	—	—	PM ISA[2]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA[2]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[2]
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
Nonfatal morbidity from exposure to ozone	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
	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[2]
	Metabolic effects (e.g., diabetes)	—	—	Ozone ISA[2]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[2]

	Cardiovascular and nervous system effects	—	—	Ozone ISA[2]
	Reproductive and developmental effects	—	—	Ozone ISA[2]

[1]Valuation estimate excludes initial hospital and/or emergency department visits.
[2] 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 the benefit per ton values that are used to estimate the benefits from changes in $PM_{2.5}$ concentrations from changes in NO_x, SO_2 and $PM_{2.5}$ emissions.

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 $PM_{2.5}$ mortality risk. We estimate counts of $PM_{2.5}$-related total deaths (y_{ij}) 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

$$y_{ij} = \Sigma_a y_{ija}$$
$$y_{ija} = mo_{ija} \times (e^{\beta \cdot \Delta C_{ij}} - 1) \times P_{ija}, \quad \text{Eq[1]}$$

where mo_{ija} 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 $PM_{2.5}$ exposure, C_{ij} is the annual mean $PM_{2.5}$ concentration in 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.[7]

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 concentrations are taken from the air pollution spatial surfaces for the analytic years 2023 and 2026 described in Chapter 3. The air pollution spatial surfaces used to estimate the $PM_{2.5}$ benefit-per-ton values are described below in Section 5.1.1.4.

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 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

[7] In this illustrative example, the air quality is resolved at the county level. For this RIA, we simulate air quality concentrations at 12km by 12km grids. The BenMAP-CE tool assigns the rates of baseline death and disease stored at the county level to the 12km by 12km grid cells using an area-weighted algorithm. This approach is described in greater detail in the appendices to the BenMAP-CE user manual.

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). Consistent with the RCU analysis 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 $PM_{2.5}$-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 2019) concluded that the analyses of the ACS and Medicare cohorts provide strong evidence of an association between long-term $PM_{2.5}$ 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 $PM_{2.5}$ related effects derived using relative risk estimates from both cohorts.

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 $PM_{2.5}$ 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).

5.1.1.5 Applying $PM_{2.5}$ Benefit per Ton Values

Implementing the proposal is expected to reduce emissions of NO_X during the May through September ozone season as well as annually from the power sector due to year-round operation of control measures. The proposal is also expected to reduce annual emissions in NO_X, $PM_{2.5}$ and SO_2 due to changes in power sector operation. Direct $PM_{2.5}$ and SO_2 reductions reduce ambient $PM_{2.5}$ concentrations year-round, while NOx emission reductions reduce $PM_{2.5}$ concentrations in the winter months. To estimate the benefits from these changes, we performed a benefit per ton analysis. For details on how these benefit per ton values are estimated, see EPA's updated *Technical Support Document Estimating the Benefit per Ton of Reducing Directly-Emitted $PM_{2.5}$, $PM_{2.5}$ Precursors and Ozone Precursors from 21 Sectors (BPT TSD)* (U.S. EPA, 2021b). The procedure for calculating benefit per ton $PM_{2.5}$ coefficients follows three steps:

1. Using source apportionment photochemical modeling, predict annual average ambient concentrations of primary $PM_{2.5}$, nitrate and sulfate attributable to each of 21 emission sectors located throughout the Continental U.S. The source apportionment modeling for the power sector uses the 2017 NEI.

2. For each sector, estimate the health impacts, and the economic value of these impacts, associated with the attributable ambient concentrations of primary $PM_{2.5}$, sulfate and nitrate $PM_{2.5}$, and Ozone from NOx and Ozone from VOC using the environmental Benefits Mapping and Analysis Program-Community Edition (BenMAP-CE v1.5.8) and the risk and valuation estimates documented in the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD.

3. For each sector, divide the $PM_{2.5}$-related health impacts attributable to each type of $PM_{2.5}$, and the monetary value of these impacts, by the level of associated precursor emissions. That is, primary $PM_{2.5}$ benefits are divided by direct $PM_{2.5}$ emissions, sulfate benefits are divided by SO_2 emissions, and nitrate benefits are divided by NOx emissions.

For this analysis, we modeled expected annual NOx, annual SO_2, annual direct-$PM_{2.5}$, and warm season NOx emissions reductions by state that reflect the effects of generation shifting or other EGU controls that are expected to operate year-round. Changes in power sector emissions are derived from the IPM analysis of the proposed rule relative to the baseline scenario (for details, please refer to Chapter 4). Depending on the sector, either state or regional benefit per ton values from the BPT TSD were multiplied by the modeled changes in $PM_{2.5}$ and $PM_{2.5}$ precursors for each state. The values were summed across pollutants then summed for each policy scenario. Benefit per ton values from 2025 were applied for years 2023-2029 and 2030 values were applied for years 2030-2042.

5.1.2 Economic Valuation Methodology for Health Benefits

We next quantify the economic value of the ozone and $PM_{2.5}$-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 $PM_{2.5}$- 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 $PM_{2.5}$-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 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), 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.

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 2025.

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. EPA is reviewing the SAB's formal recommendations.

In valuing $PM_{2.5}$-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, EPA follows the advice of the SAB-HES to use a segmented 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 $PM_{2.5}$ (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 $PM_{2.5}$ 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 emission 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.

Our estimate of the total monetized ozone and $PM_{2.5}$-attributable benefits is based on 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 $PM_{2.5}$-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 $PM_{2.5}$) 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 ≤ 40ppb 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 $PM_{2.5}$ 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 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 $PM_{2.5}$ pollutants may lead to states changing their NAAQS compliance approaches. However, we do not simulate how states would account for this proposed rule when complying with the NAAQS, which introduces uncertainty in the estimated benefits (and costs).

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 $PM_{2.5}$ 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 $PM_{2.5}$ 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 $PM_{2.5}$ 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 Figure 5-1.

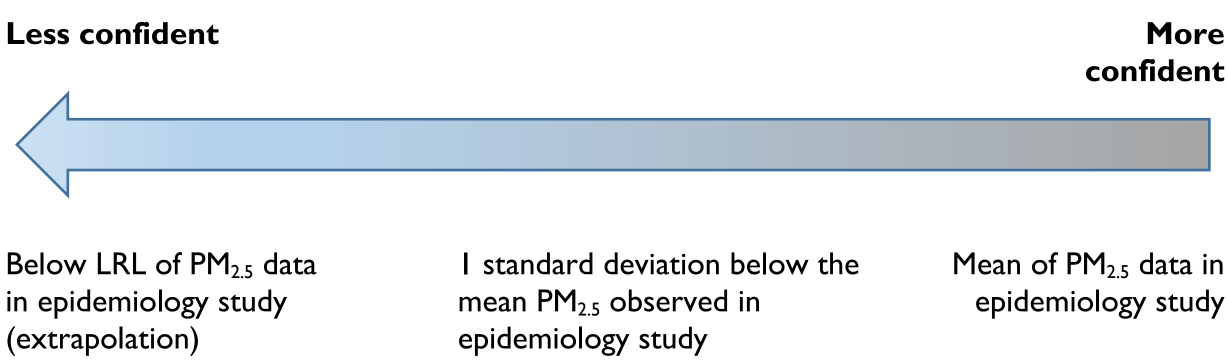

Figure 5-1. Stylized Relationship between the $PM_{2.5}$ Concentrations Considered in Epidemiology Studies and our Confidence in the Estimated PM-related Premature Deaths

For Turner et al. 2016, the LRL is 2.8 μg/m^3 and for Di et al. 2017, the LRL is 0.02 μg/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 $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD. These results are sensitive to the annual mean $PM_{2.5}$ concentration the air quality model predicted in each 12 km by 12 km grid cell. The air quality modeling predicts $PM_{2.5}$ concentrations to be at or below the annual mean $PM_{2.5}$ NAAQS (12 μg/m^3) in nearly all locations. The photochemical modeling we employ accounts for the suite of local, state and federal policies expected to reduce $PM_{2.5}$ and $PM_{2.5}$ precursor emissions in future years, such that we project a very small number of locations exceeding the annual standard. The results should be viewed in the context of the air quality modeling technique we used to estimate $PM_{2.5}$ concentrations. We are more confident in our ability to use the air quality modeling techniques described above to estimate *changes* in annual mean $PM_{2.5}$ concentrations than we are in our ability to estimate *absolute* $PM_{2.5}$ 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 and Table 5-3). The number of reduced estimated deaths and illnesses from the proposed rule and more and less stringent alternatives are calculated from the sum of individual reduced mortality and illness risk across the population. Table 5-4 and Table 5-5 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 proposal, more- and less- stringent alternatives, using the monetized sums of long-term ozone and $PM_{2.5}$ mortality and morbidity impacts (Table 5-6 and Table 5-7).[8] We also provide illustrative $PM_{2.5}$ benefits for non-EGUs below in Table 5-8.

[8] 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.

Table 5-2. Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Proposal and More and Less Stringent Alternatives for 2023 (95% Confidence Interval) [a,b]

		Proposal	More Stringent Alternative	Less Stringent Alternative[h]
Avoided premature respiratory mortalities				
Long-term exposure	Turner *et al*. (2016)[c]	44 (31 to 57)	51 (36 to 66)	44 (31 to 57)
Short-term exposure	Katsouyanni *et al.* (2009)[c,d] and Zanobetti *et al.* (2008)[d] pooled	2 (0.8 to 3.1)	2.3 (0.94 to 3.7)	2 (0.81 to 3.2)
Morbidity effects				
Long-term exposure	Asthma onset[e]	350 (300 to 390)	400 (340 to 450)	350 (300 to 400)
	Allergic rhinitis symptoms[g]	2,000 (1,000 to 2,900)	2,200 (1,200 to 3,300)	2,000 (1,000 to 2,900)
Short-term exposure	Hospital admissions—respiratory[d]	5.3 (-1.4 to 12)	6.1 (-1.6 to 14)	5.3 (-1.4 to 12)
	ED visits—respiratory[f]	110 (30 to 230)	120 (34 to 260)	110 (30 to 230)
	Asthma symptoms	62,000 (-7,700 to 130,000)	71,000 (-8,800 to 150,000)	62,000 (-7,700 to 130,000)
	Minor restricted-activity days[d,f]	30,000 (12,000 to 47,000)	34,000 (14,000 to 54,000)	30,000 (12,000 to 48,000)
	School absence days	22,000 (-3,100 to 47,000)	26,000 (-3,600 to 54,000)	22,000 (-3,200 to 47,000)

[a] Values rounded to two significant figures.

[b] We estimated ozone benefits for changes in NOx for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors 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 proposed standards would become effective.

[c] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.

[d] Converted ozone risk estimate metric from MDA1 to MDA8.

[e] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.

[f] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.

[g] Converted ozone risk estimate metric from DA24 to MDA8.

[h] The proposed rule imposes unit level emission rate limits on EGUs in the 2026, which are imposed in the 2025 IPM run year, while the less stringent alternative assumes these are imposed in 2028, and in IPM are applied in the 2028 run year. The unit level emission rate limits drive much of the EGU retirement activity, and retirements are delayed in the less stringent alternative relative to the proposed rule. Consistent with the power sector analysis in Chapter 4, the power sector model is forward looking and has an incentive to run units harder before they retire. This incentive is lower in the less stringent alternative relative to the proposed rule due to delayed retirements. As such, emissions are slightly lower in 2023 in some states in the less stringent alternative relative to the proposed rule.

Table 5-3. Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Proposal and More and Less Stringent Alternatives for 2026 (95% Confidence Interval) [a,b,h]

			Proposal	More Stringent Alternative	Less Stringent Alternative
Exposure Duration	**Study**	**Affected Facility**	**Avoided premature respiratory mortalities**		
Long-term exposure	Turner *et al*. (2016)[c]	EGUs	450 (310 to 580)	520 (360 to 670)	210 (140 to 270)
		Non-EGUs	510 (350 to 660)	550 (380 to 710)	450 (310 to 580)
		EGUs + Non-EGUs	960 (660 to 1,200)	1,100 (740 to 1,400)	650 (450 to 850)
Short-term exposure	Katsouyanni *et al.* (2009)[c,d] and Zanobetti *et al.* (2008)[d]pooled	EGUs	20 8.2 to 32)	24 (9.5 to 37)	9.4 (3.8 to 15)
		Non-EGUs	23 (9.3 to 36)	25 (10 to 39)	20 (8.2 to 32)
		EGUs + Non-EGUs	43 (18 to 68)	48 (19 to 76)	30 (12 to 47)
	Morbidity effects				
Long-term exposure	Asthma onset[e]	EGUs	3,300 (2,800 to 3,700)	3,800 (3,300 to 4,300)	1,600 (1,300 to 1,800)
		Non-EGUs	3,800 (3,300 to 4,400)	4,200 (3,600 to 4,700)	3,400 (2,900 to 3,800)
		EGUs + Non-EGUs	7,100 (6,100 to 8,100)	7,900 (6,800 to 9,000)	4,900 (4,200 to 5,600)
	Allergic rhinitis symptoms[g]	EGUs	19,000 (9,900 to 27,000)	22,000 (11,000 to 32,000)	8,900 (4,700 to 13,000)
		Non-EGUs	22,000 (12,000 to 32,000)	24,000 (13,000 to 35,000)	19,000 (10,000 to 28,000)
		EGUs + Non-EGUs	41,000 (22,000 to 59,000)	46,000 (24,000 to 66,000)	28,000 (15,000 to 41,000)
Short-term exposure	Hospital admissions—respiratory[d]	EGUs	55 (-14 to 120)	63 (-17 to 140)	25 (-6.5 to 55)
		Non-EGUs	61 (-16 to 140)	66 (-17 to 150)	54 (-14 to 120)
		EGUs + Non-EGUs	120 (-30 to 260)	130 (-34 to 290)	79 (-21 to 170)
	ED visits—respiratory[f]	EGUs	1,100 (290 to 2,200)	1,200 (340 to 2600)	500 (140 to 1,100)
		Non-EGUs	1,200 (340 to 2,600)	1,300 (360 to 2,800)	1,100 (300 to 2,300)
		EGUs + Non-EGUs	2,300 (630 to 4,800)	2,600 (700 to 5,400)	1,600 (430 to 3,300)
	Asthma symptoms	EGUs	610,000 (-75,000 to 1,300,000)	700,000 (-86,000 to 1,500,000)	290,000 (-35,000 to 590,000)
		Non-EGUs	710,000 (-87,000 to 1,500,000)	770,000 (-94,000 to 1,600,000)	620,000 (-77,000 to 1,300,000)

	EGUs + Non-EGUs	1,300,000 (-160,000 to 2,700,000)	1,500,000 (-180,000 to 3,000,000)	910,000 (-110,000 to 1,900,000)
Minor restricted-activity days[d,f]	EGUs	280,000 (110,000 to 440,000)	330,000 (13,000 to 520,000)	130,000 (53,000 to 210,000)
	Non-EGUs	330,000 (130,000 to 520,000)	360,000 (140,000 to 560,000)	290,000 (120,000 to 460,000)
	EGUs + Non-EGUs	610,000 (240,000 to 970,000)	680,000 (270,000 to 1,100,000)	420,000 (170,000 to 670,000)
School absence days	EGUs	220,000 (-30,000 to 450,000)	250,000 (-35,000 to 520,000)	100,000 (-14,000 to 210,000)
	Non-EGUs	250,000 (-35,000 to 530,000)	270,000 (-38,000 to 570,000)	220,000 (-31,000 to 460,000)
	EGUs + Non-EGUs	470,000 (-66,000 to 980,000)	520,000 (-74,000 to 1,100,000)	320,000 (-46,000 to 670,000)

[a] Values rounded to two significant figures.
[b] We estimated ozone benefits for changes in NOx for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors for EGUs in 2026.
[c] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.
[d] Converted ozone risk estimate metric from MDA1 to MDA8.
[e] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.
[f] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.
[g] Converted ozone risk estimate metric from DA24 to MDA8.
[h] Non-EGU benefits estimates are ozone-related only. An illustrative analysis of non-EGU PM benefits estimates is presented in Table 5-8.

Table 5-4. Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Proposed Policy Scenarios in 2023 (95% Confidence Interval; millions of 2016$)[a,b]

Disc. Rate	Pollutant	Proposal			More Stringent Alternative			Less Stringent Alternative		
3%	Ozone Benefits	$57 ($15 to $120)[c]	*and*	$460 ($51 to $1,200)[d]	$65 ($17 to $140)[c]	*and*	$530 ($59 to $1,400)[d]	$57 ($15 to $120)[c]	*and*	$460 ($51 to $1,200)[d]
	PM Benefits	$44	*and*	$45	$190	*and*	$190	$59	*and*	$60
	Ozone plus PM Benefits	$100 ($59 to $160)[c]	*and*	$500 ($96 to $1,200)[d]	$250 ($200 to $330)[c]	*and*	$720 ($250 to $1,600)[d]	$120 ($74 to $180)[c]	*and*	$520 ($110 to $1,300)[d]
7%	Ozone Benefits	$51 ($9.6 to 110)[c]	*and*	$410 ($42 to $1,100)[d]	$58 ($11 to $130)[c]	*and*	$480 ($49 to $1,300)[d]	$51 ($9.6 to $110)[c]	*and*	$410 ($42 to $1,100)[d]
	PM Benefits	$40	*and*	$41	$170	*and*	$170	$53	*and*	$54
	Ozone plus PM Benefits	$90 ($49 to $150)[c]	*and*	$450 ($83 to $1,100)[d]	$230 ($180 to $300)[c]	*and*	$650 ($220 to $1,400)[d]	$100 ($63 to $170)[c]	*and*	$470 ($97 to $1,100)[d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated ozone benefits for changes in NOx for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors 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 proposed standards would become effective.
[c] Using the pooled short-term ozone exposure mortality risk estimate.
[d] Using the long-term ozone exposure mortality risk estimate.

Table 5-5. Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Proposed Policy Scenario in 2026 (95% Confidence Interval; millions of 2016$)[a,b]

Disc Rate	Pollutant	Proposal			More Stringent Alternative			Less Stringent Alternative		
3%	Ozone Benefits	$1,200 ($310 to $2,600) [c]	*and*	$10,000 ($1,100 to $26,000) [d]	$1,300 (340 to $2,900) [c]	*and*	$11,000 ($1,200 to $29,000) [d]	$830 ($210 to $1,800) [c]	*and*	$6,900 ($760 to $18,000) [d]
	PM Benefits	$8,100	*and*	$8,300	$7,800	*and*	$7,900	$3,400	*and*	$3,500
	Ozone plus PM Benefits	$9,300 ($8,400 to $11,000)[c]	*and*	$18,000 ($9,400 to $35,000)[d]	$9,100 ($8,100 to $11,000)[c]	*and*	$19,000 ($9,200 to $37,000)[d]	$4,300 ($3,700 to $5,200)[c]	*and*	$10,000 ($4,300 to $22,000)[d]
7%	Ozone Benefits	$1,100 ($200 to $2,400) [c]	*and*	$9,000 ($920 to $24,000) [d]	$1,200 ($220 to $2,700) [c]	*and*	$10,000 ($1,000 to $26,000) [d]	$740 ($140 to $1,700) [c]	*and*	$6,200 ($630 to $16,000) [d]
	PM Benefits	$7,300	*and*	$7,400	$7,000	*and*	$7,100	$3,100	*and*	$3,200
	Ozone plus PM Benefits	$8,400 ($7,500 to $9,700)[c]	*and*	$16,000 ($8,300 to $31,000)[d]	$8,200 ($7,200 to $9,700)[c]	*and*	$17,000 ($8,200 to $34,000)[d]	$3,800 ($3,200 to $4,800)[c]	*and*	$9,300 ($3,800 to $19,000)[d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in NOx for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2026. This table represents changes in EGU and non-EGU ozone season and annual controls.
[c] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.
[d] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.

Table 5-6. 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 BPT $PM_{2.5}$ Mortality for EGUs (Discounted at 3%; millions of 2016$)[a]

	Proposal	More Stringent Alternative	Less Stringent Alternative
2023*	$500	$720	$520
2024	$520	$740	$530
2025	$530	$750	$550
2026*	$18,000	$19,000	$10,000
2027	$19,000	$19,000	$11,000
2028	$18,000	$19,000	$10,000
2029	$19,000	$20,000	$11,000
2030	$20,000	$21,000	$11,000
2031	$20,000	$21,000	$11,000
2032	$21,000	$22,000	$12,000
2033	$20,000	$21,000	$12,000
2034	$21,000	$22,000	$12,000
2035	$21,000	$22,000	$12,000
2036	$21,000	$22,000	$12,000
2037	$22,000	$23,000	$12,000
2038	$21,000	$22,000	$12,000
2039	$22,000	$23,000	$12,000
2040	$22,000	$23,000	$13,000
2041	$22,000	$23,000	$13,000
2042	$22,000	$23,000	$13,000
Net Present Value	***$250,000***	***$270,000***	***$150,000***

*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: $PM_{2.5}$-attributable deaths (quantified using a concentration-response relationship from the Di et al. 2017 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2017 study); and $PM_{2.5}$ and ozone-related morbidity effects.

[a] For the years 2023-2025, benefits associated with non-EGU emissions reductions are not included as implementation of proposed control technologies will not be complete until 2026.

Table 5-7. 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 BPT $PM_{2.5}$ Mortality for EGUs (Discounted at 7%; millions of 2016$)[a]

	Proposal	More Stringent Alternative	Less Stringent Alternative
2023*	$450	$650	$470
2024	$460	$660	$480
2025	$470	$670	$490
2026*	$16,000	$17,000	$9,300
2027	$17,000	$17,000	$9,400
2028	$16,000	$17,000	$9,300
2029	$17,000	$17,000	$9,500
2030	$18,000	$19,000	$10,000
2031	$18,000	$19,000	$10,000
2032	$18,000	$19,000	$10,000
2033	$18,000	$19,000	$10,000
2034	$18,000	$19,000	$10,000
2035	$19,000	$20,000	$11,000
2036	$19,000	$20,000	$11,000
2037	$19,000	$20,000	$11,000
2038	$19,000	$20,000	$11,000
2039	$19,000	$20,000	$11,000
2040	$19,000	$21,000	$11,000
2041	$19,000	$21,000	$11,000
2042	$20,000	$21,000	$11,000
Net Present Value	***$150,000***	***$160,000***	***$88,000***

*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: $PM_{2.5}$-attributable deaths (quantified using a concentration-response relationship from the Di et al. 2017 study); Ozone-attributable deaths (quantified using a pooled estimate of results quantified using concentration-response relationships two short-term exposure mortality studies); and $PM_{2.5}$ and ozone-related morbidity effects.

[a] For the years 2023-2025, benefits associated with non-EGU emissions reductions are not included as implementation of proposed control technologies will not be complete until 2026.

Since the proposed 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, the benefits estimates in Table 5-8 provide an illustration of potential $PM_{2.5}$ benefits from non-EGUs if the proposed controls are run year-round. For this proposal, we are taking comment on whether any of these emissions sources would run controls year-round. These illustrative benefits estimates are not added to the total health benefits for this proposal.

Table 5-8. Illustrative Estimates of $PM_{2.5}$-Attributable Premature Mortality and Illnesses for the Proposal for Non-EGUs (millions of 2016$)[a]

	Economic value of long-term mortality and morbidity health effects	
Sector	**Benefit Per Ton Valuation of Reducing NOx (discounted at 3%)**	**Benefit Per Ton Valuation of Reducing NOx (discounted at 7%)**
Cement Kilns	290	260
External Combustion Boilers	280	220
Integrated Iron and Steel	59	52
Oil & Natural Gas Transmission	770	680
Refineries	21	19
Synthetic Organic Chemical Industry	19	17

[a] To estimate these benefits, we multiplied annual NOx emissions reductions for the non-EGU sources by the relevant benefit per ton value. The ozone season NOx emissions reductions estimates are found in the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* discussed further in Chapter 4. To estimate annual NOx emissions reductions, the ozone season estimates are divided by 5/12. The benefit per ton values are from the BPT TSD (U.S. EPA, 2021b). We matched the industries and NOx emissions reductions from the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* to the industries and sources in the BPT TSD – approximately 80 percent of the estimated NOx emissions reductions had an applicable benefit per ton value and are reflected in the estimates in this table.

5.2 Climate Benefits from Reducing CO_2

Elevated concentrations of greenhouse gases (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.

Extensive information on climate change is available in the scientific assessments and EPA documents that are briefly described in this section, as well as in the technical and scientific information supporting them. One of those documents is EPA's 2009 Endangerment and Cause or Contribute Findings for Greenhouse Gases Under section 202(a) of the CAA (74 FR 66496, December 15, 2009). In the 2009 Endangerment Finding, the Administrator found under section 202(a) of the CAA that elevated atmospheric concentrations of six key well-mixed GHGs – CO_2, methane (CH4), nitrous oxide (N2O), HFCs, perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) – "may reasonably be anticipated to endanger the public health and welfare of current and future generations" (74 FR 66523). The 2009 Endangerment Finding, together with the extensive scientific and technical evidence in the supporting record, documented that climate change caused by human emissions of GHGs threatens the public health of the U.S. population. It explained that by raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses (74 FR 66497). While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. (74 FR 66525). The 2009 Endangerment Finding further explained that compared with a future without climate change, climate change is expected to increase tropospheric ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst tropospheric ozone problems, and thereby increase the risk of adverse effects on public health (74 FR 66525). Climate change is also expected to cause more intense hurricanes and more frequent and intense storms of other types and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders (74 FR 66525). Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects (74 FR 66498).

The 2009 Endangerment Finding also documented, together with the extensive scientific and technical evidence in the supporting record, that 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). These impacts are also global and the effects of climate change occurring outside the U.S. are reasonably expected to impact the U.S. population. (74 FR 66530).

In 2016, the Administrator issued a similar finding for GHG emissions from aircraft under section 231(a)(2)(A) of the CAA. In the 2016 Endangerment Finding, the Administrator found that the body of scientific evidence amassed in the record for the 2009 Endangerment Finding compellingly supported a similar endangerment finding under CAA section 231(a)(2)(A), and also found that the science assessments released between the 2009 and the 2016 Findings ‘‘strengthen and further support the judgment that GHGs in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future generations’’ (81 FR 54424).

Since the 2016 Endangerment Finding, the climate change impacts have continued to intensify, with new observational records being set for several climate indicators such as global average surface temperatures, GHG concentrations, and sea level rise. Moreover, heavy precipitation events have increased in the eastern United States while agricultural and ecological drought has increased in the western United States along with more intense and larger wildfires.[9] Climate impacts that occur outside U.S. borders also increasingly impact the welfare of individuals and firms that reside in the United States because of their connection to the global economy. This will occur through the effect of climate change on international markets, trade, tourism, and other activities. For example, supply chain disruptions are a prominent pathway through which U.S. business and consumers are, and will continue to be, affected by climate change impacts abroad (USGCRP 2018, U.S. DOD 2021). Additional climate change induced international spillovers can occur through pathways such as damages across transboundary resources, economic and political destabilization, and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns (U.S. DOD 2014, CCS 2018). These and other trends highlight the increased risk already being experienced due to climate change as detailed in the 2009 and 2016 Endangerment Findings. Additionally, new major scientific assessments continue to advance our understanding of the climate system and the impacts that GHGs have on public health and welfare both for current and future generations. These assessments include:

- U.S. Global Change Research Program's (USGCRP) 2016 Climate and Health Assessment and 2017–2018 Fourth National Climate Assessment (NCA4) (USGCRP 2016, 2017, 2018).
- IPCC's 2018 Global Warming of 1.5 °C, 2019 Climate Change and Land, and the 2019 Ocean and Cryosphere in a Changing Climate assessments, as well as the 2021 IPCC Sixth Assessment Report (AR6) (IPCC 2018, 2019a, 2019b, 2021).
- The National Academies of Sciences, Engineering, and Medicine's 2016 Attribution of Extreme Weather Events in the Context of Climate Change, 2017 Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide, and 2019 Climate Change and Ecosystems assessments (NAS 2016, 2017, 2019).

[9] See EPA's November 2021 Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (https://www.govinfo.gov/content/pkg/FR-2021-11-15/pdf/2021-24202.pdf) for more discussion of specific examples. An additional resource for indicators can be found at https://www.epa.gov/climate-indicators.

- National Oceanic and Atmospheric Administration's (NOAA) annual State of the Climate reports published by the Bulletin of the American Meteorological Society, most recently in August of 2020 (Blunden and Arndt 2020).
- EPA Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts (2021) (EPA 2021c).

Net climate benefits from reducing emissions of CO_2 can be monetized using estimates of the social cost of carbon (SC-CO_2). However, as explained below, due to a court order, EPA cannot present these monetized estimates in the analysis of this proposed rule at this time. The SC-CO_2 is the monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase. In principle, SC-CO_2 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_2, therefore, should reflect the societal value of reducing emissions of the gas in question by one metric ton. The SC-CO_2 is therefore, an estimate of the marginal benefit of CO_2 abatement along the baseline and the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2 emissions. In practice, data and modeling limitations naturally restrain the ability of SC-CO_2 estimates to include all of 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.

EPA and other federal agencies began regularly incorporating SC-CO_2 estimates in benefit-cost analyses conducted under Executive Order (E.O.) 12866[10] in 2008, following a court ruling in which an agency was ordered to consider the value of reducing CO_2 emissions in a rulemaking process. Specifically, the U.S. Ninth Circuit Court of Appeals remanded a fuel economy rule to DOT for failing to monetize CO_2 emission reductions, stating that "while the record shows that there is a range of values, the value of carbon emissions reduction is certainly

[10] Under E.O. 12866, agencies are required, to the extent permitted by law and where applicable, "to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." Some 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.

not zero."[11] In 2009, the U.S. Government (USG) launched an interagency process, under the leadership of the Office of Management and Budget (OMB) and the Council of Economic Advisers (CEA), to ensure that Federal agencies had access to the best available information when quantifying the benefits of reducing CO_2 emissions in regulatory impact analyses and to promote consistency in the estimated values. This included the establishment of an interagency working group (IWG) which represented perspectives and technical expertise from many federal agencies and a commitment to following the peer-reviewed literature. In 2010, the IWG finalized a set of four SC-CO_2 values recommended for use in regulatory analyses and presented them in a technical support document (TSD) that also provided guidance for agencies on how to use the estimates (IWG 2010). The SC-CO_2 estimates recommended in 2010 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 were run using a common set of input assumptions in each model for future population, economic, and GHG emissions growth, as well as equilibrium climate sensitivity (ECS) – a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM. In August 2016 the IWG published estimates of the social cost of methane (SC-CH4) and nitrous oxide (SC-N2O) using methodologies that are consistent with the methodology underlying the SC-CO_2 estimates. In January 2017, the National Academies of Sciences, Engineering, and Medicine issued recommendations for an updating process to ensure the estimates continue to reflect the best available science (National Academies 2017). In March 2017, Executive Order 13783 disbanded the IWG and instructed agencies when monetizing the value of changes in greenhouse gas emissions resulting from regulations to follow the Office of Management and Budget's (OMB) Circular A-4.

On January 20, 2021, President Biden issued E.O. 13990 which re-established the IWG and asked it to update the estimates of SC-CO_2, SC-CH_4, and SC-N_2O (collectively referred to as social cost of greenhouse gases (SC-GHG)) used by the U.S. Government (USG) to reflect the best available science and the recommendations of the National Academies (2017). On February

[11] Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin., 538 F.3d 1172, 1200 (9th Cir. 2008).

26, 2021, the IWG recommended as interim SC-GHG estimates the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The February 2021 TSD stated that the interim estimates reflected the best available scientific estimates available for agencies to use in regulatory benefit-cost analyses and other applications while the more comprehensive review was underway.

On February 11, 2022, the U.S. District Court for the Western District of Louisiana issued an injunction concerning the monetization of benefits of greenhouse gas emission reductions by EPA and other defendants. *See Louisiana v. Biden*, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Accordingly, monetized climate benefits are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. We note that the absence of monetized climate benefits from the analysis of benefits and net benefits in this RIA has no bearing on the legal or technical basis for the proposed action itself. The estimated total reductions in greenhouse gas emissions projected to result from this proposed action will have climate benefits by mitigating the impacts of climate change discussed above. Those benefits can be understood as part of the unquantified benefits of this proposal that are described in qualitative terms.

5.3 Additional Unquantified Benefits

Data, time, and resource limitations prevented EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with direct exposure to NO_2 and SO_2 (independent of the role NO_2 and SO_2 play as precursors to $PM_{2.5}$ and ozone), 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, $PM_{2.5}$, NO_2 or SO_2. In this section, we provide a qualitative description of these and water quality benefits, which are listed in Table 5-9.

Table 5-9. Unquantified Health and Welfare Benefits Categories

Category	Effect	Effect Quantified	Effect Monetized	More Information
Improved Human Health				
Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions	—	—	NO_2 ISA[1]
	Chronic lung disease hospital admissions	—	—	NO_2 ISA[1]
	Respiratory emergency department visits	—	—	NO_2 ISA[1]

	Asthma exacerbation	—	—	NO_2 ISA[1]
	Acute respiratory symptoms	—	—	NO_2 ISA[1]
	Premature mortality	—	—	NO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[2,3]
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[4]
	Reproductive and developmental effects from halogenated disinfection byproducts exposure.	—	—	SE ELG BCA[4]
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[4]
	Possible cardiovascular disease from lead exposure	—	—	SE ELG BCA[4]
	Neurological and cognitive effects from in in-utero mercury exposure from maternal fish consumption	—	—	SE ELG BCA[4]
	Skin and gastrointestinal cancer incidence from arsenic exposure	—	—	SE ELG BCA[4]
	Cancer and non-cancer incidence from exposure to toxic pollutants (lead, cadmium, thallium, hexavalent chromium etc. Neurological, alopecia, gastrointestinal effects, reproductive and developmental damage from short-term thallium exposure.	—	—	SE ELG BCA[4]
Reduced incidence of morbidity and mortality from recreational water exposure from reduced effluent discharges.	Cancer and Non-Cancer incidence from exposure to toxic pollutants (methyl-mercury, selenium, and thallium.)	—	—	SE ELG BCA[4]
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[1]
	Visibility in residential areas	—	—	PM ISA[1]
Reduced effects on materials	Household soiling	—	—	PM ISA[1,2]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[2]
Reduced effects from PM deposition (metals and organics)	Effects on individual organisms and ecosystems	—	—	PM ISA[2]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[1]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[1]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[1]
	Damage to urban ornamental plants	—	—	Ozone ISA[2]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[1]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[2]
	Other non-use effects			Ozone ISA[2]

	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[2]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_x SO_x ISA[1]
	Tree mortality and decline	—	—	NO_x SO_x ISA[2]
	Commercial fishing and forestry effects	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_x SO_x ISA[2]
Reduced effects from nutrient enrichment from deposition.	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Coastal eutrophication	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_x SO_x ISA[2]
Reduced vegetation effects from ambient exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_x SO_x ISA[2]
	Injury to vegetation from NO_x exposure	—	—	NO_x SO_x ISA[2]
Improved water aesthetics from reduced effluent discharges.	Improvements in water clarity, color, odor in residential, commercial and recreational settings.	—	—	SE ELG BCA[4]
Effects on aquatic organisms and other wildlife from reduced effluent discharges	Protection of Threatened and Endangered (T&E) species from changes in habitat and potential population effects.	—	—	SE ELG BCA[4]
	Other non-use effects	—	—	SE ELG BCA[4]
	Changes in sediment contamination on benthic communities and potential for re-entrainment.	—	—	SE ELG BCA[4]
	Quality of recreational fishing and other recreational use values.	—	—	SE ELG BCA[4]
	Commercial fishing yields and harvest quality.	—	—	SE ELG BCA[4]
Reduced water treatment costs from reduced effluent discharges	Reduced drinking, irrigation, and other agricultural use water treatment costs.	—	—	SE ELG BCA[4]
Reduced sedimentation from effluent discharges	Increased storage availability in reservoirs	—	—	SE ELG BCA[4]
	Improved functionality of navigable waterways	—	—	SE ELG BCA[4]
	Decreased cost of dredging	—	—	SE ELG BCA[4]
Benefits of reduced water withdrawal	Benefits from effects aquatic and riparian species from additional water availability.	—	—	SE ELG BCA[4]
	Increased water availability in reservoirs increasing hydropower supply, recreation, and other services.	—	—	SE ELG BCA[4]
Climate effects	Climate impacts from carbon dioxide (CO_2)	---	---	Section 5.2 discussion
	Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts)			IPCC, Ozone ISA, PM ISA

[1] We assess these benefits qualitatively due to data and resource limitations for this RIA.
[2] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.
[3] 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.
[4] 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.

5.3.1 NO_2 Health Benefits

In addition to being a precursor to $PM_{2.5}$ and ozone, NOx 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_2 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 (NOx ISA) (U.S. EPA, 2016c) concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to NO_2. 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 NOx ISA also concluded that the relationship between short-term NO_2 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_2 alone. Although the NOx ISA stated that studies consistently reported a relationship between NO_2 exposure and mortality, the effect was generally smaller than that for other pollutants such as PM.

5.3.2 SO_2 Health Benefits

In addition to being a precursor to $PM_{2.5}$, SO_2 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_2 in this analysis. Therefore, this analysis only quantifies and monetizes the $PM_{2.5}$ benefits associated with the reductions in SO_2 emissions. Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the *Integrated Science Assessment for Oxides of Sulfur —Health Criteria* (SO_2 ISA) concluded that there is a causal relationship between respiratory health effects and short-term exposure to SO_2 (U.S. EPA 2017). The immediate effect of SO_2 on the respiratory system in humans is bronchoconstriction. Asthmatics are more sensitive to the effects of SO_2 likely resulting from preexisting inflammation associated with this disease. A clear concentration-response relationship has been demonstrated in laboratory studies following exposures to SO_2 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_2 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_2 ISA. The SO_2 ISA also concluded that the relationship between short-term SO_2 exposure and premature mortality was “suggestive of a causal relationship” because it is difficult to attribute the mortality risk effects to SO_2 alone. Although the SO_2 ISA stated that studies are generally consistent in reporting a relationship between SO_2 exposure and mortality, there was a lack of robustness of the observed associations to adjustment for other pollutants.

5.3.3 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.

5.3.4 NO_2 and SO_2 Welfare Benefits

As described in the Integrated Science Assessment (ISA) for Oxides of Nitrogen, Oxides of Sulfur and Particulate Matter Ecological Criteria (NOx/SOx/PM ISA) (U.S. EPA, 2020d), NOx and SO_2 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 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)

5.3.5 Visibility Impairment Benefits

Reducing secondary formation of $PM_{2.5}$ 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 emission 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_2 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).

5.3.6 Water Quality and Availability Benefits

As described in Chapter 4, this proposed 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 below. [12] 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).

[12] 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.

Potential Water Quality Benefits of Reducing Coal-Fired Power Generation

Discharges of wastewater from coal-fired power plants can contain toxic and bio-accumulative 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. EPA expects the ecological impacts from reducing coal-fired power plant discharges could include habitat changes for fresh- 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.

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 by a lag between detection of changes in source water contaminants and the system implementing treatment to address the issue. This lag 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.

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.

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.

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 species primarily comes from the nonuse values people hold for the survivorship of both individual organisms and species survival.

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).

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; Ribaudo 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. 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.

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 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.

5.3.7 Hazardous Air Pollutant Impacts

The proposed rule is expected to reduce fossil-fired EGU generation by up to 8 percent per year 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

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 proposed 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 proposed rulemaking. For additional discussion of impacts on fuel use and electricity prices, see Chapter 4, Section 4.5.3.

6.1 Small Entity Analysis

For the proposed rule, the EPA performed a small entity screening analysis for impacts on all affected EGUs and non-EGU facilities[1] 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)[2] 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).

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[1] The facilities were identified in the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026*, or non-EGU screening assessment, available in the docket.
[2] 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 >

6.1.1 EGU Small Entity Analysis and Results

This section presents the methodology and results for estimating the impact of the proposal on small EGU entities in 2023 and in 2026 based on the following endpoints:

- annual economic impacts of the proposal on small entities, and
- ratio of small entity impacts to revenues from electricity generation.

In this analysis, EPA considered EGUs that are subject to the proposed 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 proposal; 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, EPA identified a total of 130 potentially affected EGUs warranting examination in 2023 and 481 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.[3] Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.[4] 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.

[3] 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.
[4] 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.

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.
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, 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).[5] In these cases, the ultimate parent entity was identified via D&B Hoover's, whether domestically or internationally owned.

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.[6] SBA guidelines list all industries, along with their associated North American Industry Classification System (NAICS) code[7] and SBA size standard. Therefore, it was necessary to identify the specific NAICS code associated with each ultimate parent entity in order 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

[5] 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.
[6] SBA's table of size standards can be located here: https://www.sba.gov/document/support--table-size-standards.
[7] North American Industry Classification System can be accessed at the following link: https://www.census.gov/naics/

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 4-3. 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.

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		1000
221210	Natural Gas Distribution		1000
221310	Water Supply and Irrigation Systems	$30	
221320	Sewage Treatment Facilities	$22	
221330	Steam and Air-Conditioning Supply	$16	

Note: Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective August 19, 2019. Available at the following link: https://www.sba.gov/document/support--table-size-standards).
Source: SBA, 2019

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.[8] In parallel, EPA also considered estimated revenues from affected EGUs based on analysis of IPM parsed-file[9] 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.[10] EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination.

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 2023 EPA identified 130 potentially affected EGUs, owned by 68 entities. Of these, EPA identified 15 potentially affected EGUs owned by 9 small entities included in EPA's power sector baseline. In 2026 total EPA identified 481 potentially affected EGUs, owned by 157 entities. Of these, EPA identified 56 potentially affected EGUs owned by 34 small entities included in the power sector baseline.

In 2023, an entity can comply with the proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (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

[8] Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.
[9] 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.
[10] The Regulatory Flexibility Act defines a small government jurisdiction as the government of a city, county, 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.

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 proposed 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[11], and Δ R represents the change in revenues, calculated as the difference in value of electricity generation between the baseline case and the proposed rule in 2023 or 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 proposed 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 proposed 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 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 proposal on small entities.

For this analysis, 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

[11] 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.

under the proposed 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 $1,800 (2016$) per ton for 2023 and $10,000 (2016$) per ton in 2026, which is the marginal cost of NO_X reductions used to set the modeled budgets in the proposed FIP for the 2015 ozone NAAQS. While this is a reasonable approximation, the analysis of the proposal which is the source of other costs and revenues used in this calculation, shows a lower projected allowance price. Units were assumed to purchase or sell allowances to exactly cover their projected emissions under the proposed FIP for the 2015 ozone NAAQS.

(3) **Fuel costs** ($\Delta\ C_{Fuel}$)**:** The change in fuel expenditures under the proposed FIP for the 2015 ozone NAAQS was estimated by taking the difference in projected fuel expenditures between the IPM estimates for the proposed FIP for the 2015 ozone NAAQS and the baseline.

(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 NO_X 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 proposed FIP for the 2015 ozone NAAQS on small entities are summarized in Table 6-2 and Table 6-3. All costs are presented in 2016$. EPA estimated the annual net compliance cost to small entities to be approximately $1.7 million in 2023 and $31 million in 2026.

Table 6-2. Projected Impact of the Proposed FIP for the 2015 Ozone NAAQS on Small Entities in 2023

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	Number of Small Entities with Compliance Costs >3% of Generation Revenues
Municipal	2	1.1	0	0
IOU	7	0.6	0	0
Total	**9**	**1.7**	**0**	**0**

Source: IPM analysis

Table 6-3. Projected Impact of the Proposed 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	Number of Small Entities with Compliance Costs >3% of Generation Revenues
Municipal	13	3	3	3
IOU	7	36	3	1
Private	10	-9.3	0	0
Co-op	4	1.8	0	0
Total	**34**	**31**	**6**	**4**

Source: IPM analysis

EPA assessed the economic and financial impacts of the proposed 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. Although this metric is commonly used in EPA impact analyses, it makes the most sense when as a general matter an analysis is looking at small businesses that operate in competitive environments.[12] However, small businesses in the electric power industry often operate in a price-regulated environment where they are able to recover expenses through rate increases. Of the 9 small entities considered in this analysis, none are projected to experience compliance costs greater than 1 percent of generation revenues in 2023. Of the 34 entities considered in this analysis, 6 are projected to experience compliance costs greater than 1% of generation revenues in 2026, and 4 are projected to experience compliance costs greater than 3% of generation revenues in 2026.

6.1.2 Non-EGU Small Entity Impacts and Results

We identified 250 facilities, using the non-EGU screening assessment for 2026 discussed in Chapter 4, owned by 85 parent companies, using information from D&B Hoover's[13], that

[12] U.S. EPA. EPA's Action Development Process. Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as Amended by the Small Business Regulatory Enforcement Fairness Act. September 2006. Available at https://www.epa.gov/sites/production/files/2015-06/documents/guidance-regflexact.pdf.

[13] 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.

could be affected by the proposed rule. Of the parent companies, five companies, or two 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 SBA's table of size standards to determine which of the companies were small entities. Table 6-4 below includes the ranges NAICS codes and SBA entity size guidelines for small entity parent companies.

Table 6-4. Non-EGU SBA Size Standards by NAICS Code

NAICS Codes	NAICS U.S. Industry Title	Size Standards (million$)	Size Standards (number of employees)
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	$30	
322110	Pulp Mills		750
322121	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

Also, we calculated the cost-to-sales ratios for all of the affected entities to determine (i) the magnitude of the costs of the proposal, 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 6-5 for *all* firms the average cost-to-sales ratio is approximately 0.1 percent; the median cost-to-sales ratio is less than 0.01 percent; and the maximum cost-to-sales ratio is approximately 1.4 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 1.4 percent. For *small* firms, the average cost-to-sales ratio is approximately 0.7 percent, the median cost-to-sales ratio is 0.5 percent, and the maximum cost-to-sales ratio is 1.3 percent.

Table 6-5. 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	5	2.0%	0.7%	0.5%	0.3%	1.3%
Large	245	98.0%	0.1%	<0.0%	<0.0%	1.4%
All	250	100.0%	0.1%	<0.0%	<0.0%	1.4%

As mentioned above, we compare annual compliance costs to annual revenues at the ultimate parent company level. For the small entities, the small parent companies are the small facilities; in other words, the small parent companies each own one small facility. Table 6-6 below includes the small parent companies and their projected cost-to-sales ratio, NAICS code, and small business size standards. The facility-specific costs for the small parent companies ranged from $227 thousand to $1.8 million annually (2016$).

Table 6-6. Summary of Small Parent Company Small Business Size Standards

Small Parent Company	NAICS	Cost to Sales Ratio	Number of Employees	SBA Size Standard: Number of Employees
Cstn Holdings, Inc.	325199	1.3%	600	1,250
Angus Chemical Company	325199	0.7%	500	1,250
Futurefuel Corp.	325199	0.5%	548	1,250
Capital Aggregates	327310	0.4%	525	1,000
Glass Energy Company, Inc.	327213	0.3%	353	1,250

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 in 2023 and in 2026 and for non-EGUs in 2026 separately and combined the 2026 results for a SISNOSE determination for the proposed rule.

For EGUs, estimates indicate that there are nine small entities that see a +/- 1 percent change in either summer NOx emissions, summer generation, or summer fuel use in 2023, and none are projected to have a cost-to-sales impact greater than 1 percent of their revenues in 2023. In 2026, the analysis indicates that 34 small entities see a +/- 1 percent change in either summer NOx emissions, summer generation or summer fuel use, and 6 of these are projected to have a cost impact of greater than 1 percent of their revenues in 2026.

In 2026, EPA identified 157 possibly affected EGU entities. Of these, EPA identified 34 small entities affected by the proposal, and of these 6 small entities may experience costs of greater than 1 percent of revenues. Of the 6 small entities projected to have costs greater than 1 percent of revenues, two operate in cost-of-service regions and would generally be able to pass any increased costs along to ratepayers. In EPA's modeling, most of the cost impacts for these small entities and their associated units are driven by lower electricity generation relative to the baseline. Specifically, four units reduce their generation by significant amounts, driving the bulk of the costs for all small entities. Finally, EPA's decision to exclude units smaller than 25 MW capacity from the proposed FIP, and exclusion of uncontrolled units smaller than 100 MW from backstop emission rate limits 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 five small entities, and one small entity is estimated to have a cost-to-sales impact of 1.3 percent of their revenues.

Based on this analysis, for this proposal overall we conclude that the estimated costs for the proposed 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 proposed 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 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. 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. 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 proposed 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.[14]

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 proposed rule. The estimated employment difference between these scenarios can be interpreted as the incremental effect of the proposed rule on employment in this sector. As discussed in Chapter 4, there is

[14] 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.

uncertainty related to the future baseline projections. 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 also excludes the economy-wide effects of changes to energy markets (such as higher or lower forecasted electricity prices). At the same time, this approach excludes labor impacts that are usually included in a benefits analysis for an 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.[15] 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

[15] https://www.usenergyjobs.org/

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 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 proposed 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.[16]

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

[16] 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/.

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 additional 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.

6.2.4 Projected Sectoral Employment Changes due to the Proposed Rule

Affected EGUs may respond to the proposed 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 proposed rule, 32 GW of SCR installations are projected by the 2025 run year, and an incremental 18 GW of coal and 4 GW of oil/gas retirements are projected by 2030. Additionally, an incremental 14 GW of non-hydro renewable additions are also projected under the proposed rule by the 2025 run year. These are primarily comprised of solar builds that occur earlier in the forecast period relative to the baseline projections as a result of the increased fossil thermal retirements.

Based on these power sector modeling projections, we estimate a sizable increase in construction-related jobs related to the installation of new pollution controls under the proposed option, as well as the construction of new generating capacity (largely solar PV). In 2025, we estimate an increase of over 150,000 construction-related job-years. Some of this capacity is projected to be built earlier under the policy case than the baseline (which explains the estimated decrease in 2030). 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 6-7 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). Negative construction job-year estimates occur when additional generating capacity is projected to be built in the baseline, but not projected to be built under the proposed rule.

Table 6-7. Changes in Labor Utilization: Construction-Related (Number of Job-Years of Employment in a Single Year)

	2023	2025	2028	2030
New Pollution Controls	600	11,400	<100	<100
New Capacity	<100	139,600	9,700	-43,900

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 new built capacity, create a stream of negative job-years. The proposed rule is projected to result, generally, in a replacement of relatively labor-intensive coal capacity with less labor-intensive capacity (primarily solar), which results in an overall decrease of non-construction jobs. The proposed rule is also projected to result in a small reduction in recurring employment related to fuel extraction. The total net estimated decrease in recurring employment is less than 7,500 job years in 2025, 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 6-8 provide detailed estimates of recurring non-construction employment changes.

Table 6-8. Changes in Labor Utilization: Recurring Non-Construction (Number of Job-Years of Employment in a Single Year)

	2023	**2025**	**2028**	**2030**
Pollution Controls	<100	<100	-100	-100
Existing Capacity	<100	-11,200	-11,800	-9,700
New Capacity	<100	4,300	5,200	3,600
Fuels (Coal, Natural Gas, Uranium)	<100	-600	-900	-500
Coal	*<100*	*-600*	*-1,000*	*-1,000*

Natural Gas	*<100*	*<100*	*<100*	*200*
Uranium	*<100*	*<100*	*100*	*200*

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 proposed rule, focusing on the directly regulated industries and groups of affected workers. The directly regulated firms in non-EGU industries fall into two tiers of industries[17] (Table 6-9):

- Tier 1 industries that have a maximum contribution to any one receptor of >0.10 ppb and (2) contribute >= 0.01 ppb to at least 10 receptors, and
- Tier 2 industries that either have (1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors.

The proposed rule only covers specific boilers in the Tier 2 industries and not every emissions unit in those industries. Table 6-9 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 of the Tier 1 industries 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 contracted in 2020 from the COVID-19 pandemic. The iron and steel mills and

[17] See Chapter 4, Section 4.4 for further discussion of the industry tiers.

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.[18]

Table 6-9. Relevant Industry Employment (2020)

	NAICS	Employment (Thousands)	Percent Change 2011 - 2020
Tier 1 Industries			
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%
Tier 2 Industries			
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%

Source: BLS

These industries are capital intensive. We rely on three 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, and employment and output by industry provided by the U.S. Bureau of Labor Statistics (BLS). 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 6-10 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 cement and concrete product manufacturing.

[18] Bureau of Labor Statistics. BLS Employment, Hours, and Earnings from the Current Employment Statistics survey (National), All-employees, May 2021

Table 6-10. Employment per $1 million Output in the Tier 1 Industries

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
Glass and Glass Product Manufacturing	3.34	3.35

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 proposed 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 (largely solar PV). The proposed rule is also projected to result, generally, in a replacement of relatively labor-intensive coal capacity with less labor-intensive capacity (primarily solar), which results in an overall decrease of non-construction jobs. 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.

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CHAPTER 7: ENVIRONMENTAL JUSTICE IMPACTS

7.1 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 (59 FR 7629, February 16, 1994). Additionally, Executive Order 13985 was signed to advance racial equity and support underserved communities through Federal government actions (86 FR 7009, January 20, 2021). EPA defines environmental justice (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. 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".[1] 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.[2] 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 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.

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[1] See, e.g., "Environmental Justice." *Epa.gov*, U.S. Environmental Protection Agency, 4 Mar. 2021, https://www.epa.gov/environmentaljustice.

[2] See https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.

A regulatory action may involve potential environmental justice 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, EPA relies upon its June 2016 "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,"[3] which provided recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time and resource constraints, and analytical challenges will vary by media and circumstance.

A reasonable starting point for assessing the need for a more detailed environmental justice 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 environmental justice analysis. EJ analyses can be grouped into two types, both of which are informative, but not always feasible for a given rulemaking:

1. <u>Baseline</u>: Describes the current (pre-control) distribution of exposures and risk, identifying potential disparities.

2. <u>Policy</u>: Describes the distribution of exposures and risk after the control strategy has been applied (post-control), identifying how potential disparities change in response to the rulemaking.

[3] See https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.

EPA's 2016 Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting an environmental justice analysis, 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 Proposal

In addition to the benefits assessment (Chapter 5), EPA considers potential environmental justice (EJ) concerns of this proposed rulemaking.[4] Although EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, EPA's EJ Technical Guidance[5] 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, EPA developed an analytical approach that considers the purpose and specifics of the proposed rulemaking, as well as the nature of known and potential exposures and impacts. For example, while we recognize that the proposal is focused on reducing NOx emissions to ensure states meet their obligations under the "Good Neighbor" provision of the Clean Air Act to eliminate significant contributions to, or interference with maintenance of, the 2015 ozone National Ambient Air Quality Standards (NAAQS), this proposed rulemaking may also reduce other pollutant emissions such as NO_2. Like other oxides

[4] 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, 2015a). For analytic 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, 2015a).

[5] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

of nitrogen, NO_2 can contribute to the formation of ozone downwind of sources; however, direct emissions of NO_2 can also lead to localized exposures that may be associated with respiratory effects in nearby populations at sufficiently high concentrations. While NO_2 exposures and concentrations were not estimated as part of this proposal, the proximity analysis allows for the possibility that such exposures may be relevant to the baseline and/or change due to this proposed action. Due to the potential for reductions in NO_2 concentration nearby affected sources, EPA conducts two proximity analyses to evaluate the potential EJ implications of changes in pollutants (Section 3): a demographic proximity analyses of populations residing near affected facilities (Section 7.3.1), and tribal proximity analyses of affected facilities (Section 7.3.2). EPA also conducts an analysis of reductions in ozone concentrations nationwide resulting from the NOx emission reductions projected to occur under the proposed rule, characterizing distributional exposures both prior to and following implementation of the regulatory alternatives in 2023 and 2026 (Section 7.4). Each analysis involves unique limitations and uncertainties, 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 proximity of vulnerable populations to environmental hazards 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 location such as noise, odors, and traffic. We include the following proximity screening analyses to characterize the potential for communities with EJ concerns to be impacted by emissions sources covered under this EPA action.

Although baseline proximity analyses are presented here, several important caveats should be noted. In most areas, emissions are not expected to increase from the proposed rulemaking, so most communities nearby affected facilities should not experience increases in exposure from directly emitted pollutants. However, facilities may vary widely in terms of the risk they already pose to nearby populations and 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 1 or 2 above from EPA's EJ Technical Guidance.

- *<u>Electricity Generating Unit (EGU)</u>*: 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.
- *<u>Non-EGU (non-electric generating units, or other stationary emissions sources)</u>*: 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.
- *<u>Tribal</u>*: Analysis of tribes and unique tribal lands within 50 miles of covered facilities.

7.3.1 EGU and Non-EGU Proximity Assessments

The current analysis identified all census blocks 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.[6] 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 each block's population provided by the decennial Census.[7] 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-EGU facilities). In calculating the total populations, to avoid

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[6] 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 and represents the maximum 50 km modeling domain for exposure modeling. The 10 km distance was added to this analysis as few to no people were within 5 km of some affected facilities.

[7] 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.

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 851 EGU facilities at the 5 km, 10 km, and 50 km radius distances (Table 7-1). Approximately 196 million people live within 50 km of the EGU facilities, representing roughly 60% 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 23.9 million and 65.5 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. Minorities constitute about 55% of the population within 5 km and 10 km of EGU facilities, which is about 15% greater than the national average of 40% minorities. The higher minority population is driven largely by a higher Hispanic/Latino population (about 10% above national average) and a higher African American population (about 3% 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 2-3% higher within 5 km and 10 km of the EGU facilities than the national average. About 8% to 9% of the population within 5 km and 10 km of the EGU facilities is living in linguistic isolation, this is more than 1.5 times higher than the national average (about 5%).

Table 7-1. Population Demographics for EGU Facilities

Demographic Group		Percent of Population Within Each Distance Compared to the National Average[1]			
		5km	10km	50km	National Average
Race/ Ethnicity	White	44.1%	44.9%	58.2%	60.1%
	Minority[2]	55.9%	55.1%	41.8%	39.9%
	African American	14.7%	15.4%	12.9%	12.2%
	Native American	0.3%	0.3%	0.4%	0.7%
	Other and Multiracial	11.1%	11.2%	9.0%	8.2%
	Hispanic or Latino[3]	29.7%	28.1%	19.4%	18.8%
Age	0-17 Years Old	22.4%	22.7%	22.5%	22.6%
	18-64 Years Old	63.7%	63.1%	62.2%	61.7%
	>=65 Years Old	13.9%	14.2%	15.3%	15.7%
Income	People Living Below the Poverty Level	16.3%	15.5%	13.1%	13.4%
Education	>= 25 Years Old Without a High School Diploma	16.7%	15.8%	12.7%	12.1%
Language	People Living in Linguistic Isolation	9.0%	8.4%	5.4%	5.4%
Total Population		23,863,069	65,522,012	196,411,623	328,016,242

[1] 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.

[2] Minority population is the total population minus the white population.

[3] 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 this action, a demographic analysis was also conducted for 251 non-EGU facilities at the 5 km, 10 km, and 50 km radius distances (Table 7-2). Approximately 92 million people live within 50 km of the non-EGU facilities, representing roughly 37% 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 2.8 million and 9.4 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 very similar. Minorities constitute about 39% of the population within 5 km and 40% of the population within 10 km of non-EGU facilities, which is the same or slightly less than the national average of 40% minorities. The age distribution for the population within 5 km and 10 km of non-EGU facilities is similar to the national average. The percent of people living below the poverty level is about 3-4% higher within 5 km and 10 km of the non-EGU facilities 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 lower (about 4%) than 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[1]			
		5km	**10km**	**50km**	**National Average**
Race/ Ethnicity	White	61.3%	60.1%	61.2%	60.1%
	Minority[2]	38.7%	39.9%	38.8%	39.9%
	African American	13.0%	15.4%	13.3%	12.2%
	Native American	0.6%	0.5%	0.4%	0.7%
	Other and Multiracial	7.7%	6.9%	7.4%	8.2%
	Hispanic or Latino[3]	17.4%	17.0%	17.7%	18.8%
Age	0-17 Years Old	23.7%	23.1%	22.3%	22.6%
	18-64 Years Old	60.9%	61.3%	62.1%	61.7%
	>=65 Years Old	15.4%	15.6%	15.5%	15.7%
Income	People Living Below the Poverty Level	17.6%	16.0%	13.8%	13.4%
Education	>= 25 Years Old Without a High School Diploma	14.2%	13.3%	12.9%	12.1%
Language	People Living in Linguistic Isolation	4.3%	3.9%	4.7%	5.4%
Total Population		2,819,973	9,437,895	91,874,288	328,016,242

[1] 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.

[2] Minority population is the total population minus the white population.

[3] 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.

Overall, the baseline demographic proximity analyses suggest that larger percentages of Hispanics, Blacks, 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 people below the poverty level and with less educational attainment living within 5 km and 10 km of a non-EGU facility. Relating these results to question 1 from Section 7.1, we find that there may be potential EJ concerns associated with environmental stressors affected by the regulatory action (e.g., NO_2) for certain population groups of concern in the baseline, although NO_2 air quality modeling was not performed. Additionally, concerns suggested by the proximity analyses results cannot be related to potential impacts from this proposed rulemaking resulting from ozone concentration decreases due to long-range transport.

For additional information on the proximity analyses, see the memorandum *Analysis of Demographic Factors For Populations Living Near EGU and Non-EGU Facilities*, in the proposed rulemaking docket.

7.3.2 Tribal Lands Proximity Assessment

We conducted a tribal analysis to identify the total number of EGU and non-EGU facilities located on and within 50 miles of tribal lands (Table 7-3).[8] For the purpose of this assessment, tribal lands refer to all lands associated with Federally recognized tribal entities.[9] Using Geographic Information System (GIS) to map tribal lands and facilities, EPA found that of the 851 EGUs included in this action, 38 are located on tribal lands and 176 are located within a 50-mile distance. Of the 251 non-EGUs facilities included in this action, 9 are located on tribal lands and 87 non-EGUs are located within a 50-mile distance.

Table 7-3. Tribal Proximity Assessment

	Total Number of Affected Sources	Number of Affected Sources with Tribes Within 50 Miles*	Number of Affected Sources Located on Tribal Lands
EGUs	851	176	38
Non-EGUs	251	87	9
EGUs and Non-EGUs	1,102	168	47

* The total number of tribes within 50 miles of facilities is not a direct sum. Tribes located within 50 miles of both an EGU and non-EGU facility are only counted once.

8 It has been established through tribal consultation that a 50-mile (not kilometer) radius from tribal lands is a sufficient distance to accomplish a tribal proximity analysis to address any concerns that a tribe might have on a specific action.

9 This includes Federally recognized Reservations, Off-Reservation Trust Lands, and Census Oklahoma Tribal Statistical Areas (OTSA).

7.4 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 proposal, we also assess the impact of NOx emission 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 proposed rule, as well as of the more and less stringent regulatory alternatives, in 2023 and 2026. Under the proposed rule and more stringent scenario, the year of full compliance is 2026 for both EGUs and non-EGUs. Under the less stringent scenario the year of full compliance is 2028 for EGUs and 2026 for non-EGUs. Population variables considered include race/ethnicity, poverty status, educational attainment, age, and sex (Table 7-4).[10,11]

Table 7-4. Populations Included in the Ozone Exposure Analysis

Demographic Characteristics	Description
Ethnicity	Hispanic, Non-Hispanic
Race	Asian, American Indian, Black, White
Educational Attainment	High school degree or more, No high school degree
Poverty Status	Above/below 200% of the poverty line, Above/below the poverty line
Age	Children (0-17), Adults (18-64), Older Adults (65-99)
Sex	Female, Male

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

[10] Due to the consent decree deadline, we did not have time to evaluate or bring in stratified baseline incidence rates or concentration-response functions relating to potentially evaluate 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.

[11] 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. 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).

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). This is 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.[12] 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, 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. Most health studies rely on a metric such as the warm-season average ozone concentration; as a result, 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, 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, we

[12] Level of 70 ppb with an annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years.

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 3-3 in Chapter 3, Section 3.4 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 national- and state-level aggregated results (Section 7.4.1) and then examine spatially resolved distributional results via figures (Section 7.4.2). Maps were not included as the magnitude of differences between populations observed is relatively small and ozone gradients are relatively smooth (Section 7.1.1).

7.4.1 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; Section 7.4.1.1) and regulatory alternative results in relative terms (i.e., the change in AS-MO3 concentrations; Sections 7.4.1.2).

7.4.1.1 Baseline Assessment

Before evaluating the impacts of the proposal, it is important to understand baseline, or pre-proposal, conditions. Below are the average baseline maximum daily 8-hour average ozone concentrations in parts per billion (ppb) over the April-September warm season in the two modeled future years, 2023 and 2026 (Figure 7-1). These concentrations 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 concentrations, with white coloring representing the lowest concentrations and dark orange coloring representing the highest.

Due to existing regulatory control programs reflected in the baseline, average ozone concentrations are estimated to decrease across the overall population 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., total population of contiguous U.S.), certain populations are estimated to experience higher average ozone concentrations in the baseline in both future years. The five populations with the largest differences from the national average ozone concentration within the subpopulation in both 2023 and 2026 as compared to the overall reference group were: American Indians, Hispanics, Asians, the less educated, and children. These populations live in areas with seasonal average baseline ozone concentrations of approximately 2.0, 1.9, 1.2, 0.3 and 0.2 ppb higher than the national average concentrations, respectively.[13] 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; aggregating results may underestimate the impact in individual locations where there is both an ozone nonattainment issue and a disproportionately large racial/ethnic population. Additionally, while AS-MO3 exposures across all groups are relatively low, in the range of 40-43 ppb, these seasonal averages 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 higher daily maximum exposures than others in the baseline.

[13] 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.

Population Groups	Populations (Age Range)	Year 2023	2026
Reference	All (0-99)	41.50	41.01
Ethnicity	Non-Hispanic (0-99)	41.04	40.50
	Hispanic (0-99)	43.36	42.94
Race	White (0-99)	41.59	41.10
	Asian (0-99)	42.65	42.19
	Black (0-99)	40.33	39.79
	American Indian (0-99)	43.53	43.07
Educational Attainment	More educated (high school or more) (25-99)	41.36	40.87
	Less educated (no high school) (25-99)	41.81	41.33
Poverty Status	Above 200% of the poverty line (0-99)	41.52	41.03
	Below 200% of the poverty line (0-99)	41.47	40.97
	Above poverty line (0-99)	41.52	41.02
	Below poverty line (0-99)	41.42	40.93
Age	Children (0-17)	41.73	41.23
	Adults (18-64)	41.54	41.05
	Older Adults (64-99)	41.10	40.61
Sex	Females (0-99)	41.49	41.00
	Males (0-99)	41.51	41.02

Figure 7-1. Heat Map of the National Average AS-MO3 Ozone Concentrations Across Demographic Groups in the Baseline Assessment (ppb)

Connecting back to question 1 from EPA's EJ Technical Guidance, the national-level baseline assessment of ozone concentrations suggests that there may be potential EJ concerns associated with environmental stressors affected by the regulatory action for certain population groups of concern in the 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.

7.4.1.2 Regulatory Alternatives Assessment

While the baseline provides information regarding overall ozone exposures, it does not provide information regarding how the proposed rulemaking will impact various populations. To better understand this, we evaluated how NOx emissions reductions affecting ozone concentrations downwind affected average ozone concentrations experienced by each subpopulation under the regulatory alternatives in 2023 and 2026, again with dark orange coloring representing the highest ozone concentration (Figure 7-2).[14] Although NOx reductions from this proposed rule will also reduce concentrations of fine particle ($PM_{2.5}$) and NO_2 and this proposed rule is also projected to reduce carbon dioxide (CO_2) emissions, this analysis is only a partial representation of the distributions of potential impacts.

Figure 7-2 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 proposal, the less stringent alternative, and the more stringent alternative. Under the proposed rule, the population-weighted seasonal average ozone reduction in the overall reference group is approximately 0.02 ppb in 2023 and 0.36 ppb in 2026. In 2026, roughly 0.17 ppb of ozone concentration reductions are attributable to affected EGUs and 0.20 ppb are attributable to non-EGU affected facilities. Hispanics, Asians, and American Indians are estimated to experience reductions in AS-MO3 that are slightly less than the reference group in both 2023 and 2026.[15] Pairing these results with the national baseline ozone concentrations shown in Section 7.4.1.1 suggests that although this proposal 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, Blacks and non-Hispanics, who on average experience lower ozone concentrations than the reference group under the baseline, are estimated to experience average ozone concentration reductions slightly greater than the reference group in 2023 and 2026 (e.g., roughly 0.06 ppb greater reduction in ozone concentrations than the reference group).[16] Again, these differences are small relative to

[14] The proposed rule identifies unit level emissions rates on EGUs in the 2025 run year, while the less stringent alternative identifies these emissions rates in the 2028 run year. The unit level emissions rate limits drive much of the EGU retirement activity, and retirements are delayed in the less stringent alternative relative to the proposed rule. 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 less stringent alternative relative to the proposed rule due to delayed retirements. As such, emissions are slightly lower in 2023 in some states in the less stringent alternative relative to the proposed rule, leading to slightly greater emission reductions.

[15] A smaller or greater ozone concentration reduction is defined as at least a 0.2 ppb less than the national average ozone concentration within the subpopulation in 2026.

[16] Due to the consent decree deadline, we did not have time to evaluate or bring in stratified baseline incidence rates or concentration-response functions relating to potentially evaluate at-risk populations. As results of a risk analysis lacking stratified concentration-response and/or baseline incidence rates would not provide additional information

the overall reduction in ozone concentrations across all populations. We report analytics only to the hundredths decimal place for ppb of ozone, as uncertainty with regard to modeling accuracy is likely larger for very small differences.

Under the less stringent regulatory alternative in 2023 there are similar magnitudes of ozone concentration reductions in the reference group as in the proposed rule, and a greater reduction in average ozone concentration in the more stringent regulatory alternative, within all population groups.[17] 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 proposed 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 relative population-weighted AS-MO3 ozone concentration reduction contributions from EGUs and non-EGUs can be directly compared in 2026. For all regulatory control alternatives and across all populations, non-EGU NOx emission reductions are estimated to result in greater ozone concentration reductions than the EGU NOx emissions reductions. The difference is relatively small under the policy and more stringent alternatives but is greater under the less stringent alternative.

regarding population group impacts beyond exposure differences and age-related difference in baseline incidence, this EJ analysis was limited to exposure only.

[17] The proposed rule identifies unit level emissions rates on EGUs in the 2025 run year, while the less stringent alternative identifies these emissions rates in the 2028 run year. The unit level emissions rate limits drive much of the EGU retirement activity, and retirements are delayed in the less stringent alternative relative to the proposed rule. 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 less stringent alternative relative to the proposed rule due to delayed retirements. As such, emissions are slightly lower in 2023 in some states in the less stringent alternative relative to the proposed rule, leading to slightly greater emission reductions.

			2023					2026					
		Policy	Less	More	Policy			Less			More		
Population Groups	Populations (Age Range)	EGU	EGU	EGU	EGU	NonEGU	EGU+ NonEGU	EGU	NonEGU	EGU+ NonEGU	EGU	NonEGU	EGU+ NonEGU
Reference	All (0-99)	0.02	0.02	0.02	0.17	0.20	0.36	0.08	0.17	0.25	0.19	0.21	0.41
Ethnicity	Non-Hispanic (0-99)	0.02	0.02	0.02	0.18	0.21	0.39	0.08	0.18	0.27	0.21	0.22	0.44
	Hispanic (0-99)	0.01	0.01	0.01	0.11	0.15	0.26	0.06	0.14	0.19	0.13	0.17	0.30
Race	White (0-99)	0.02	0.02	0.02	0.17	0.19	0.36	0.08	0.17	0.25	0.19	0.21	0.40
	Asian (0-99)	0.01	0.01	0.01	0.11	0.17	0.28	0.05	0.15	0.20	0.14	0.18	0.32
	American Indian (0-99)	0.01	0.01	0.01	0.12	0.16	0.28	0.06	0.14	0.20	0.14	0.17	0.31
	Black (0-99)	0.02	0.02	0.02	0.20	0.22	0.42	0.09	0.19	0.29	0.23	0.24	0.47
Educational Attainment	More educated (25-99)	0.02	0.02	0.02	0.17	0.20	0.36	0.08	0.17	0.25	0.20	0.21	0.41
	Less educated (no high school) (25-99)	0.02	0.02	0.02	0.16	0.19	0.35	0.08	0.17	0.24	0.18	0.21	0.39
Poverty Status	Above 200% of the poverty line (0-99)	0.02	0.02	0.02	0.17	0.20	0.36	0.08	0.17	0.25	0.19	0.21	0.41
	Below 200% of the poverty line (0-99)	0.02	0.02	0.02	0.17	0.20	0.37	0.08	0.17	0.25	0.20	0.21	0.41
	Above poverty line (0-99)	0.02	0.02	0.02	0.17	0.20	0.36	0.08	0.17	0.25	0.19	0.21	0.41
	Below poverty line (0-99)	0.02	0.02	0.02	0.17	0.20	0.37	0.08	0.17	0.26	0.20	0.22	0.41
Age	Children (0-17)	0.02	0.02	0.02	0.17	0.20	0.37	0.08	0.18	0.26	0.20	0.22	0.41
	Adults (18-64)	0.02	0.02	0.02	0.17	0.20	0.36	0.08	0.17	0.25	0.19	0.21	0.41
	Older Adults (64-99)	0.02	0.02	0.02	0.17	0.19	0.36	0.08	0.17	0.25	0.19	0.21	0.40
Sex	Females (0-99)	0.02	0.02	0.02	0.17	0.20	0.37	0.08	0.17	0.25	0.20	0.21	0.41
	Males (0-99)	0.02	0.02	0.02	0.17	0.20	0.36	0.08	0.17	0.25	0.19	0.21	0.41

Figure 7-2. Heat Map of the National Average AS-MO3 Ozone Concentration Reductions by Demographic Group, Regulatory Alternative, and Affected Facilities (ppb)

The goal of this proposed 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.[18] As upwind emissions reductions necessary to achieve this goal will not affect ozone concentrations uniformly within each state, we provide AS-MO3 ozone concentration reductions by state and demographic population for the combined EGU and non-EGU proposed alternative in 2026 for the 48 states in the contiguous U.S. (Figure 7-3). In this heat map dark orange indicates larger AS-MO3 reductions, 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 1.02 ppb and populations potentially of concern are projected to experience reductions in AS-MO3 concentrations by up to 1.15 ppb.

Air quality improvements across demographic groups within individual states are variable. For example, although nationally Hispanics experienced a smaller improvement in air quality than the overall average, this effect was observed in only 14 of the 48 states. In addition, for Hispanics there were greater average improvements of AS-MO3 concentrations in the two states with the largest AS-MO3 concentration reductions, Kentucky and Louisiana. Therefore,

[18] See Section 1 of the proposal preamble for a discussion of the states included in the proposal and their proposed requirements for EGUs and non-EGUs.

small differences in air quality improvements observed at the national level are not experienced consistently across geographic areas.

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 reduction occurs in Kentucky, as of 2021 it is the 26th most populated state with approximately 4.5 million people and will contribute less to the national population-weighted AS-MO3 information than California.

Year / Regulatory Alternative / Facilities / Population Groups / Populations
2026
Policy
EGU+ NonEGU

	Ref	Race/Ethnicity						Poverty Status				Education		Ages			Sex	
State	All	Non-Hispanic	Hispanic	White	Asian	Black	Amer Indian	Above 200% of poverty line	Above poverty line	Below 200% of poverty line	Below poverty line	Less educated	More educated	Children (0-17)	Adults (18-64)	Older Adults (65-99)	Females	Males
Alabama	0.39	0.39	0.39	0.40	0.39	0.38	0.41	0.40	0.40	0.39	0.39	0.39	0.40	0.39	0.39	0.40	0.39	0.39
Arizona	0.04	0.05	0.04	0.04	0.04	0.04	0.06	0.04	0.04	0.04	0.05	0.04	0.04	0.04	0.04	0.05	0.04	0.04
Arkansas	0.89	0.90	0.80	0.87	0.81	1.02	0.79	0.89	0.89	0.89	0.89	0.87	0.89	0.89	0.89	0.89	0.89	0.89
California	0.11	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.11	0.11	0.11	0.11	0.10	0.11	0.11	0.10	0.11	0.11
Colorado	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Connecticut	0.23	0.23	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Delaware	0.38	0.38	0.39	0.38	0.40	0.39	0.38	0.39	0.39	0.38	0.38	0.38	0.38	0.39	0.39	0.38	0.39	0.38
Florida	0.09	0.10	0.07	0.09	0.10	0.09	0.11	0.10	0.09	0.09	0.09	0.09	0.09	0.10	0.09	0.09	0.09	0.10
Georgia	0.27	0.27	0.28	0.28	0.29	0.27	0.28	0.28	0.28	0.27	0.27	0.27	0.28	0.27	0.27	0.27	0.27	0.27
Idaho	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.02
Illinois	0.71	0.72	0.66	0.71	0.66	0.73	0.69	0.71	0.71	0.72	0.73	0.71	0.71	0.71	0.71	0.72	0.71	0.71
Indiana	0.84	0.84	0.78	0.84	0.82	0.81	0.81	0.84	0.84	0.83	0.83	0.83	0.84	0.83	0.84	0.84	0.84	0.84
Iowa	0.38	0.38	0.37	0.38	0.39	0.40	0.35	0.38	0.38	0.38	0.39	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Kansas	0.45	0.45	0.43	0.45	0.47	0.47	0.47	0.45	0.45	0.45	0.45	0.44	0.45	0.45	0.45	0.45	0.45	0.45
Kentucky	1.02	1.02	1.07	1.01	1.09	1.15	1.03	1.05	1.04	0.97	0.96	0.94	1.03	1.03	1.02	1.02	1.02	1.02
Louisiana	0.97	0.97	1.00	0.97	1.00	0.98	0.87	0.98	0.98	0.96	0.96	0.96	0.98	0.97	0.98	0.97	0.98	0.97
Maine	0.10	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Maryland	0.43	0.43	0.43	0.44	0.44	0.42	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
Massachusetts	0.17	0.17	0.16	0.17	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.16	0.17	0.17	0.17
Michigan	0.62	0.62	0.65	0.62	0.63	0.63	0.56	0.62	0.62	0.62	0.62	0.62	0.62	0.63	0.62	0.61	0.62	0.62
Minnesota	0.27	0.27	0.27	0.27	0.28	0.27	0.22	0.27	0.27	0.26	0.26	0.26	0.27	0.27	0.27	0.26	0.27	0.27
Mississippi	0.73	0.73	0.76	0.74	0.79	0.72	0.68	0.73	0.73	0.73	0.73	0.72	0.73	0.73	0.73	0.73	0.73	0.73
Missouri	0.81	0.81	0.73	0.79	0.88	0.91	0.72	0.82	0.81	0.78	0.79	0.80	0.81	0.80	0.81	0.81	0.81	0.81
Montana	0.03	0.03	0.03	0.03	0.02	0.03	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Nebraska	0.26	0.26	0.26	0.26	0.27	0.28	0.25	0.26	0.26	0.25	0.26	0.25	0.26	0.26	0.26	0.25	0.26	0.26
Nevada	0.07	0.07	0.07	0.07	0.08	0.08	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
New Hampshire	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
New Jersey	0.32	0.32	0.31	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
New Mexico	0.11	0.10	0.11	0.11	0.10	0.11	0.09	0.11	0.11	0.11	0.11	0.11	0.10	0.11	0.11	0.10	0.11	0.11
New York	0.28	0.29	0.27	0.29	0.27	0.27	0.28	0.28	0.28	0.28	0.28	0.27	0.28	0.28	0.28	0.29	0.28	0.28
North Carolina	0.32	0.32	0.32	0.32	0.32	0.32	0.28	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
North Dakota	0.09	0.10	0.09	0.10	0.10	0.10	0.08	0.10	0.09	0.09	0.09	0.09	0.10	0.09	0.10	0.09	0.10	0.09
Ohio	0.76	0.76	0.74	0.76	0.78	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.75	0.76	0.76
Oklahoma	0.62	0.63	0.61	0.62	0.63	0.63	0.65	0.63	0.62	0.62	0.62	0.62	0.63	0.62	0.62	0.63	0.63	0.62
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
Pennsylvania	0.49	0.50	0.45	0.50	0.47	0.46	0.47	0.49	0.49	0.49	0.49	0.48	0.50	0.49	0.49	0.50	0.49	0.49
Rhode Island	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
South Carolina	0.24	0.24	0.24	0.24	0.25	0.23	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
South Dakota	0.17	0.17	0.18	0.17	0.18	0.19	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Tennessee	0.56	0.55	0.58	0.54	0.58	0.64	0.55	0.55	0.56	0.56	0.56	0.55	0.55	0.57	0.56	0.54	0.56	0.56
Texas	0.46	0.51	0.41	0.45	0.50	0.53	0.48	0.48	0.47	0.44	0.43	0.43	0.47	0.46	0.47	0.47	0.47	0.46
Utah	0.21	0.21	0.23	0.21	0.23	0.23	0.19	0.22	0.21	0.21	0.21	0.21	0.21	0.22	0.22	0.20	0.21	0.21
Vermont	0.20	0.20	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
Virginia	0.45	0.45	0.45	0.46	0.45	0.43	0.45	0.45	0.45	0.46	0.46	0.46	0.45	0.45	0.45	0.46	0.45	0.45
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
West Virginia	0.70	0.70	0.65	0.70	0.69	0.68	0.70	0.70	0.70	0.70	0.71	0.69	0.70	0.70	0.70	0.70	0.70	0.70
Wisconsin	0.46	0.46	0.51	0.46	0.47	0.52	0.43	0.46	0.46	0.47	0.47	0.47	0.46	0.47	0.47	0.46	0.47	0.46
Wyoming	0.17	0.17	0.18	0.18	0.17	0.18	0.13	0.18	0.17	0.17	0.18	0.18	0.17	0.18	0.18	0.17	0.17	0.17

Figure 7-3. Heat Map of State Average AS-MO3 Ozone Concentration Reductions by Demographic Group for EGUs and Non-EGUs Under the Proposed Rule (ppb)

Connecting back to question 2 from EPA's EJ Technical Guidance again, the aggregated analyses of ozone exposures under the various regulatory alternatives in 2023 and 2026 do not suggest that there may be potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups evaluated.

7.4.2 Distributional Results

While aggregated national- and state-level average ozone concentration results (Section 7.4.1) 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 proposal, 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., Asians) 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 in that same range. 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 increasing baseline ozone concentration (Section 7.4.2.1) and ozone concentration changes from NOx emission reductions under the regulatory alternatives (Section 7.4.2.2). 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 AS-MO3 exposure. We also did not evaluate whether concentrations experienced by different groups persist across the distribution of air quality. 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 either the baseline or the proposal.

7.4.2.1 Baseline Assessment

Under baseline conditions approximately 80% of the overall reference population (i.e., total population of the contiguous U.S.) resides in areas of AS-MO3 ozone concentrations at or less than about 45 ppb in 2023 and at or less than about 44 ppb in 2026 (Figure 7-4). 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.

As was observed in the national average ozone concentration analysis (Section 7.4.1), projected ozone concentration distributions for some populations visibly differed from the reference population distribution in 2023 and 2026. Notably, there were proportionally more Hispanics and American Indians residing in areas of ozone concentrations above approximately 40 ppb than in other demographic groups evaluated. Conversely, at 30-38 ppb AS-MO3 the Hispanic population is exposed to disproportionately lower ozone concentrations than the White population, reducing the overall impact observed in the national average above. The distribution of the Asian population's exposure to ozone concentrations also indicated proportionally higher exposures as compared to the reference population, but to a lesser degree and across nearly the full array of ozone concentrations. There was also a slight shift in the distribution of less educated populations at ozone concentrations above about 43 ppb, indicating that a greater proportion of less educated people reside in areas of slightly higher ozone concentrations than more educated people. Exposure of populations differing by poverty status, age, and sex did not differ from the reference population with regard to national average ozone concentrations (Figure 7-1). These populations also did not substantially differ across the distribution of baseline ozone concentrations in 2023 and 2026 (Figure 7-4).

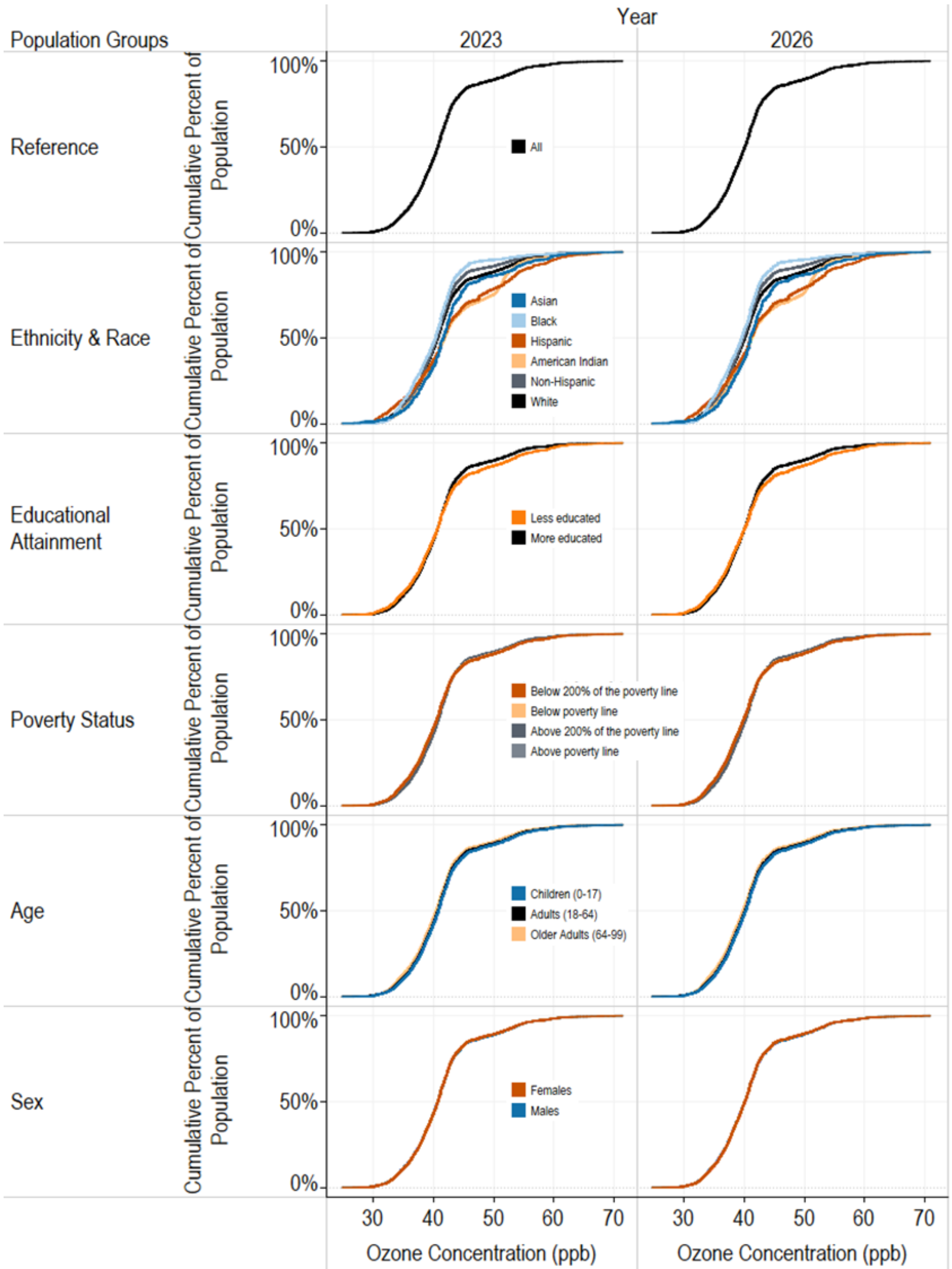

Figure 7-4. Distributions of Baseline Ozone Concentrations Across Populations in 2023 and 2026

Connecting back to question 1 from EPA's EJ Technical Guidance again, this distributional analysis of baseline ozone concentrations further supports that there may be potential EJ concerns associated with environmental stressors affected by the regulatory action for certain population groups of concern evaluated in the baseline.

7.4.2.2 Regulatory Alternatives Assessment

Distributions of 12 km gridded ozone concentration reductions from NOx emission reductions in 2023 and 2026 are shown in Figure 7-5 and Figure 7-6, respectively. As with the national average results (Section 7.4.1.1), the horizontal axes scales are different than in the baseline analyses, indicating the disproportionate impacts of the proposal are substantially smaller than under baseline conditions.

NOx emission reductions from affected EGUs under the three regulatory alternatives analyzed in this proposed rulemaking are evaluated in 2023 (Figure 7-5). Approximately 90% of the overall reference population experienced an ozone concentration reduction of less than 0.04 ppb.

There are slight differences in the ozone concentration reductions across population demographics and regulatory alternatives. Proportionally, Hispanics, Asians, and American Indians 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 Blacks is greater than the reference population only in the smallest half of ozone concentration reductions.

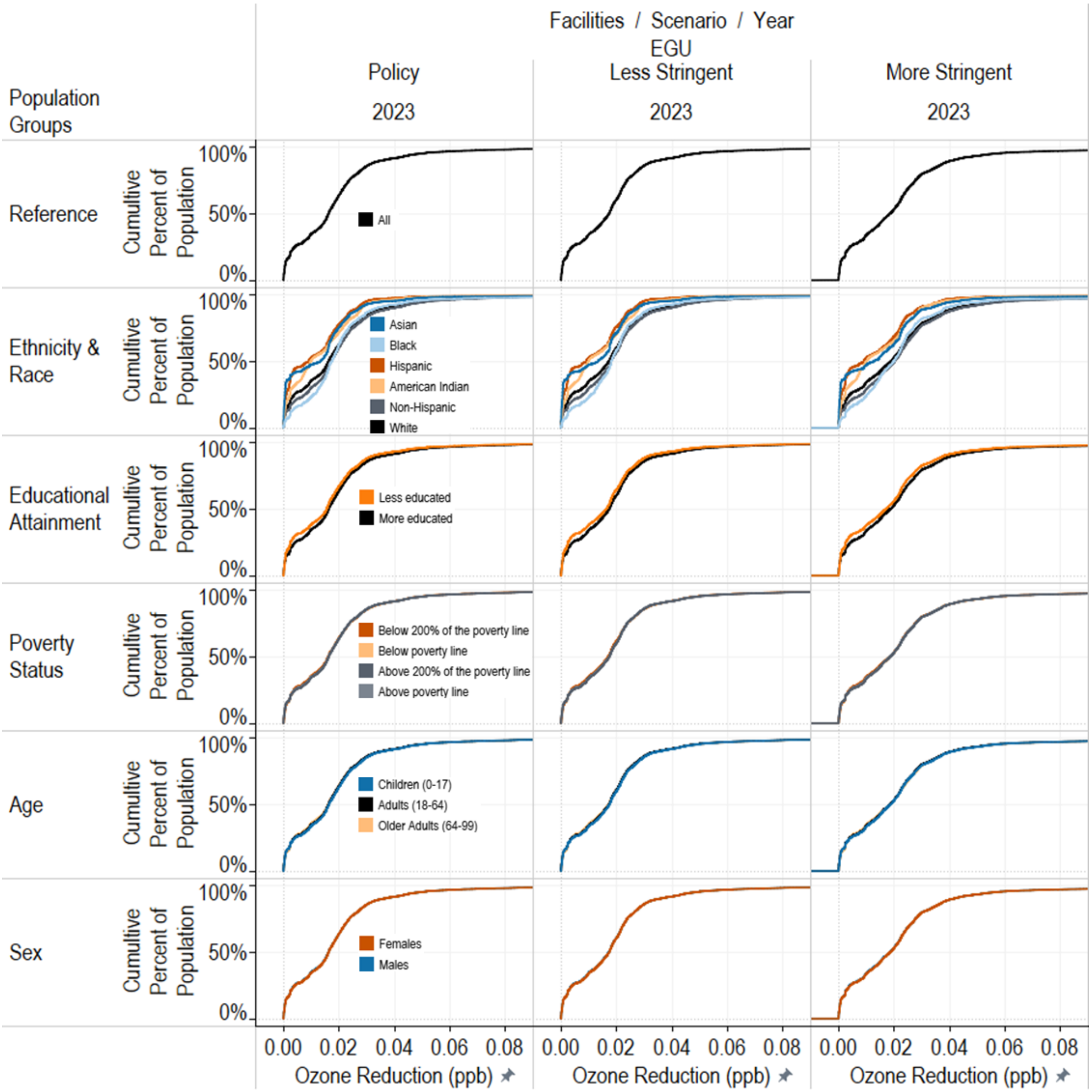

Figure 7-5. Distributions of Ozone Concentration Reductions from EGU NOx Emission Reductions Across Regulatory Alternatives and Populations in 2023

NOx emission reductions from affected EGU and non-EGU facilities under the three regulatory alternatives analyzed in this proposed rulemaking in 2026 are evaluated in Figure 7-5. The magnitude of ozone concentration reductions from affected EGUs 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.

There are differences in the ozone concentration reductions across population demographics and affected facility types. However, distributions are reasonably similar across the three regulatory alternatives. Hispanics, Asians, and American Indians experience proportionally smaller ozone concentration reductions from EGU and non-EGU NOx emission reductions under the regulatory alternatives than the overall reference population in 2026. Alternatively, the distribution of ozone concentration reductions for Blacks is greater than the reference population. This shift is greatest in the 30% of the population experiencing the smallest ozone concentration reductions from EGU NOx emission reductions.

There is a shift in the distribution of ozone concertation reductions between more and less educated populations in 2026 that differs by affected facility. Less educated people experience disproportionately smaller ozone concentration reductions from affected EGUs at lower ozone concentration reductions (approximately less than 0.2 ppb), whereas less educated people experience disproportionately smaller ozone concentration reductions from affected non-EGUs at larger ozone concentration reductions (approximately greater than 0.2 ppb).

As shown in Figure 7-6, both above and below the poverty line and 200% of the poverty line were evaluated, with comparisons between both being very similar. Across about the 60^{th}-90^{th} percentiles of people below the poverty line or 200% of the poverty line in 2026 experience disproportionately smaller ozone concentration reductions from affected EGUs and non-EGUs, as shown by the small shifts to the right in the population distributions. Substantial differences in ozone exposure reductions were not observed in the distributions of populations stratified by age or sex.

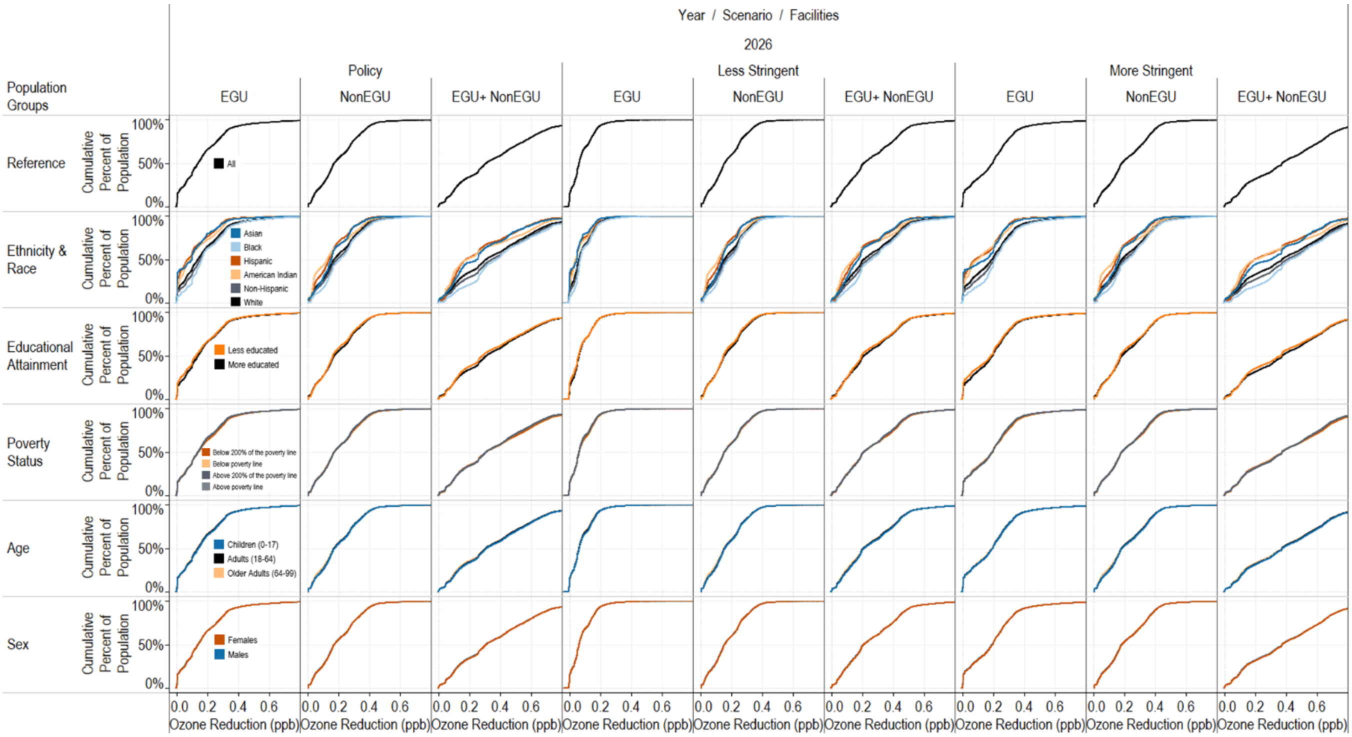

Figure 7-6. Distributions of Ozone Concentration Reductions from NOx Emission Reductions Across Affected Facilities, Regulatory Alternatives, and Populations in 2026

Connecting back to questions 2 and 3 from EPA's EJ Technical Guidance again, the distributional analyses of ozone concentrations changes under the various regulatory alternatives in 2023 and 2026 do not find evidence of potential EJ concerns associated with environmental stressors affected by the regulatory action (e.g., ozone concentrations) for population groups evaluated.

7.5 Qualitative Assessment of CO_2

CO_2 reductions are also predicted for this proposed rulemaking, although they were not modeled for baseline or regulatory alternatives under this proposed rulemaking. Therefore, similar analyses of disproportionate CO_2 impacts, as was done for ozone concentrations in Section 7.4, could not be performed. However, a brief qualitative discussion of the EJ impacts of climate change is provided.

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),[19,20] the Intergovernmental Panel on Climate Change

[19] 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.

[20] 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

(IPCC),[21,22,23,24] and the National Academies of Science, Engineering, and Medicine[25,26] 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*[27] 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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[22] 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.

[23] 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.

[24] 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.

[25] National Research Council. 2011. America's Climate Choices. Washington, DC: The National Academies Press. https://doi.org/10.17226/12781.

[26] 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.

[27] USGCRP, 2016: The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment

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.[28] The report found that Blacks and African Americans 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_2 reductions from NOx emission reductions under this proposed rule 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 proposed rule on the multiple climate-EJ interactions described above, we cannot analyze the potential impacts of the proposed rule quantitatively.

7.6 Qualitative Assessment of $PM_{2.5}$

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). Particulate matter with a mean aerodynamic diameter less than or equal to 2.5 µm ($PM_{2.5}$) reductions are expected from this proposed action but were not modeled for baseline or regulatory alternatives under this proposed rulemaking. Therefore, similar analyses of disproportionate $PM_{2.5}$ impacts, as was done for ozone concentrations in Section 7.4, could not be performed. However, a brief qualitative discussion of the potential for disproportionate $PM_{2.5}$ impacts is provided.

In general, both recent publications and analyses by the EPA suggest that the burden of $PM_{2.5}$ exposures and impacts may disproportionately affect certain groups, such as Black and

[28] EPA 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430-R-21-003.

Hispanic populations (e.g., Bell 2012, Bravo 2016, Kelly 2021, U.S. EPA 2020, U.S. EPA 2021a, U.S. EPA 2021c). $PM_{2.5}$ reductions from NOx emission reductions under this proposed rule may have benefits for disproportionately impacted populations. However, as we have not conducted air quality modeling of $PM_{2.5}$, we cannot analyze these potential impacts of the proposed rule quantitatively.

7.7 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. 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.

For the proposal, we quantitatively evaluate 1) the proximity of affected facilities to potentially disadvantaged populations (Section 7.3.1), 2) the potential for disproportionate total ozone concentrations in the baseline across different demographic groups (Sections 7.4.1.1 and 7.4.2.1), and 3) how regulatory alternatives differentially impact the ozone concentration changes experienced by different demographic populations (Sections 7.4.1.2 and 7.4.2.2). 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 are relevant for identifying which populations may be exposed to near-source pollutants, such as NO_2 emitted from affected sources in this proposed rule, however such analyses do not account for the potential impacts from this proposed rulemaking from long-range ozone concentration decreases. Baseline demographic proximity analyses can also provide information as to whether there may be potential EJ concerns associated with environmental stressors affected by the regulatory action for certain population groups of concern in the baseline. The baseline demographic proximity analysis finds larger percentages of Hispanic individuals, Black individuals, people below the poverty level, people with less educational attainment, and people linguistically isolated living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of people below the poverty level and with less educational attainment living within 5 km and 10 km of an affected non-EGU. Separately, the tribal proximity analysis finds multiple tribes and unique tribal lands located within 50 miles of an affected facility. These results cannot be used to demonstrate disproportionate impacts of affected facilities in the baseline but could suggest that population groups of concern in the baseline may be disproportionately impacted by any potential local environmental stressors affected by the regulatory action.

While the demographic proximity analyses may appear to parallel the baseline analysis of nationwide AS-MO3 ozone concentrations in certain ways, the two should not be directly compared. This is because the demographic proximity analysis does not include information on baseline or policy-specific ozone concentration information. The AS-MO3 ozone concentration assessment is in effect an analysis of total ozone burden in the contiguous U.S. in 2023 and 2026, including various assumptions such as the implementation of promulgated regulations. It serves as a starting point for both the estimated ozone changes due to this proposal as well as a snapshot of AS-MO3 ozone concentrations in the near future.

The baseline analysis of AS-MO3 ozone concentrations responds to question 1 from EPA's EJ Technical Guidance document more directly than the proximity analyses, as it evaluates a form of the environmental stressor primarily affected by the regulatory action. Baseline AS-MO3 analyses show that certain populations, such as American Indians, Hispanics, and Asians, may experience disproportionately higher AS-MO3 concentrations compared to the national average. The less educated and children may also experience higher concentrations compared to the national average, but to a lesser extent. Conversely, Black populations may experience lower AS-MO3 concentrations than the national average. Therefore, there likely are potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline.

The third type of EJ analysis presented here evaluates how regulatory alternatives of this proposal are expected to differentially impact demographic populations, informing questions 2 and 3 from EPA's EJ Technical Guidance with regard to AS-MO3 exposure changes. Overall, AS-MO3 concentrations under the proposal, more stringent, and less stringent alternatives are predicted to impact demographic groups very similarly in both future years and across both EGUs and non-EGUs. While national-level results found slightly smaller AS-MO3 ozone concentration improvements for Hispanic, Asian, and Native American populations and greater but consistent AS-MO3 ozone concentration improvements for Black populations, state-level results showed this difference was highly variable across areas. Additionally, the magnitude of these differences in air quality improvement is at or near the limit of uncertainty with regard to our ability to distinguish meaningful health impacts as well as air quality modeling accuracy.

Therefore, regarding AS-MO3 concentrations, there may be potential baseline EJ concerns that will be affected by the regulatory action for certain population groups of concern (question 1). However, we do not find evidence of meaningful EJ concerns associated with AS-MO3 concentrations after imposition of the proposed regulatory action or alternatives under consideration (question 2). We also do not find evidence that any potential EJ concerns related to AS-MO3 would be meaningfully exacerbated in the regulatory alternatives under consideration, compared to the baseline (question 3). Importantly, the action described in this proposal is expected to lower ozone in many areas, including residual ozone nonattainment areas, and thus mitigate some pre-existing health risks of ozone across all populations evaluated.

7.8 References

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CHAPTER 8: COMPARISON OF BENEFITS AND COSTS

Overview

EPA performed an analysis to estimate the costs and benefits of compliance with the proposed Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (FIP for the 2015 ozone NAAQS) and more and less stringent alternatives. EPA is proposing to promulgate new or revised FIPs for 25 states that include new NO_X ozone season emission budgets for electric generating unit (EGU) sources, with implementation of these emission budgets beginning in the 2023 ozone season. EPA is also proposing to adjust these states' emission budgets for each ozone season thereafter to maintain the initial stringency of the emissions budget, accounting for retirements and other changes to the fleet over time. EPA is also proposing to extend the CSAPR NOx Ozone Season Group 3 Trading Program beginning in the 2023 ozone season through the 2025 ozone season. EPA is proposing to establish new emissions budgets for the CSAPR NOx Ozone Season Group 3 Trading Program beginning in the 2026 ozone season, as discussed in Section VII.B.1. of the preamble.

EPA is also proposing to promulgate new FIPs for 23 states that include new NO_X emissions limitations for non-electric generating unit (non-EGU) sources, with initial compliance dates for these emissions limitations beginning in 2026.

For the RIA, in order to implement the OMB Circular A-4 requirement for fulfilling Executive Order (E.O.) 12866 to assess one less stringent and one more stringent alternative to the proposed rule, for the EGUs, all three alternatives use emission budgets that were developed using uniform control stringency represented by $1,800 per ton of NO_X (2016$) in 2023 and $11,000 per ton of NOx (2016$) in 2026. The less stringent alternative imposes backstop emission rate limits in the 2028 run year (reflective of imposition in the 2027 calendar year), while the proposed rule and more stringent alternative impose backstop emission rate limits in the 2025 run year (reflective of imposition in the 2026 calendar year) that force uncontrolled units to either install NOx controls or retire. For the proposed rule and more stringent alternative, backstop emission rate limits are imposed on all coal units within the 23-state region that are greater than 100 MW and lack SCR controls. Emission rate limits are also imposed on all oil/gas steam units within the linked states that are greater than 100 MW and lack SCR controls that operated at a greater than 20 percent historical capacity factor. In addition to the backstop rate limits present in the proposed rule and the less stringent alternative, the more stringent alternative also imposes backstop emission rate limits on all oil/gas steam units in the affected states that are greater than 100 MW, lack SCR controls and have operated at below a 20 percent capacity factor historically.

The proposal also includes NO_X emissions limitations with an initial compliance date of 2026 applicable to certain non-EGU stationary sources in 23 states. The proposed rule establishes NO_X 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; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; and impactful boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. In order to implement the OMB Circular A-4 requirement for fulfilling Executive Order (E.O.) 12866 to assess one less stringent and one more stringent alternative to the proposed rule, we analyzed a less stringent non-EGU alternative that assumes there are emissions limits for all emission units from the proposed rule alternative except for boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. We analyzed a more stringent non-EGU alternative that assumes emissions limits for all emission units from the proposed rule alternative and all boilers, not just impactful boilers, in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. A summary of the proposed 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 proposed rule are expected to reduce their emissions in response to the requirements and flexibilities provided by the remedy implemented by the proposed FIP for the 2015 ozone NAAQS and the benefits, costs and impacts of their expected compliance behavior. This chapter summarizes these results. Table 8-1 shows the ozone season NO_X emissions reductions expected from the proposed 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 annual NO_X, SO_2, $PM_{2.5}$, and CO_2 emissions reductions expected from the proposed rule as well as the more and less stringent alternatives analyzed from 2023 through 2030, and for 2035 and 2042. Table 8-2 below provides a summary of the 2019 ozone season emissions for non-EGUs for the 23 states subject to the proposed FIP in 2026, along with the estimated ozone season reductions for the proposal and the less and more stringent alternatives.

Table 8-1. EGU Ozone Season NO_X Emissions Changes and Annual Emissions Changes for NO_X, SO_2, $PM_{2.5}$, and CO_2 for the Regulatory Control Alternatives from 2023 - 2042

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
2023			
NOx (ozone season)	6,000	6,000	7,000
NOx (annual)	10,000	10,000	10,000
SO_2 (annual)*	--	1,000	2,000
CO_2 (annual, thousand metric)	--	--	--
$PM_{2.5}$ (annual)	--	--	--
2024			
NOx (ozone season)	26,000	14,000	29,000
NOx (annual)	42,000	22,000	45,000
SO_2 (annual)	42,000	20,000	43,000
CO_2 (annual, thousand metric)	18,000	10,000	19,000
$PM_{2.5}$ (annual)	4,000	1,000	4,000
2025			
NOx (ozone season)	46,000	22,000	51,000
NOx (annual)	73,000	33,000	80,000
SO_2 (annual)	83,000	39,000	84,000
CO_2 (annual, thousand metric)	37,000	19,000	38,000
$PM_{2.5}$ (annual)	9,000	2,000	9,000
2026			
NOx (ozone season)	47,000	32,000	53,000
NOx (annual)	81,000	55,000	87,000
SO_2 (annual)	106,000	76,000	108,000
CO_2 (annual, thousand metric)	40,000	26,000	42,000
$PM_{2.5}$ (annual)	9,000	5,000	9,000
2027			
NOx (ozone season)	49,000	42,000	54,000
NOx (annual)	88,000	76,000	95,000
SO_2 (annual)	129,000	113,000	131,000
CO_2 (annual, thousand metric)	43,000	34,000	46,000
$PM_{2.5}$ (annual)	10,000	7,000	10,000
2030			
NOx (ozone season)	52,000	52,000	57,000
NOx (annual)	96,000	98,000	100,000
SO_2 (annual)	104,000	100,000	103,000
CO_2 (annual, thousand metric)	50,000	45,000	50,000

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
$PM_{2.5}$ (annual)	9,000	9,000	9,000
2035			
NOx (ozone season)	49,000	50,000	52,000
NOx (annual)	90,000	93,000	93,000
SO_2 (annual)	96,000	93,000	98,000
CO_2 (annual, thousand metric)	38,000	36,000	38,000
$PM_{2.5}$ (annual)	11,000	12,000	10,000
2042			
NOx (ozone season)	47,000	47,000	48,000
NOx (annual)	70,000	75,000	71,000
SO_2 (annual)	54,000	50,000	54,000
CO_2 (annual, thousand metric)	25,000	23,000	24,000
$PM_{2.5}$ (annual)	8,000	9,000	8,000

* SO_2 emissions reductions under the proposed rule are 350 tons and rounded to zero. SO_2 emissions reductions under the less stringent alternative are 507 tons and rounded to 1000 tons. SO_2 emissions reductions are 1,699 tons under the more stringent alternative and rounded to 2,000 tons. Given the rounding, the difference between the reductions under the proposed rule and the less stringent alternative is approximately 160 tons.

Table 8-2. Non-EGU Ozone Season (OS) NO_X Emissions and Emissions Reductions for the Proposed Rule and the Less and More Stringent Alternatives

State	2019 OS NOx Emissions	Proposed Rule - OS NOx Reductions	Less Stringent Alternative - OS NOx Reductions	More Stringent Alternative - OS NOx Reductions
AR	8,265	1,654	922	1,654
CA	14,579	1,666	1,598	1,777
IL	16,870	2,452	2,452	2,553
IN	19,604	3,175	2,787	3,175
KY	11,934	2,291	2,291	2,291
LA	35,831	6,769	4,121	6,955
MD	2,365	45	45	45
MI	18,996	2,731	2,731	3,093
MN	17,591	673	673	789
MO	9,109	3,103	3,103	3,103
MS	12,284	1,761	1,577	1,761
NJ	2,025	0	0	29
NV	2,418	0	0	0
NY	6,003	500	389	613
OH	19,729	2,790	2,611	2,814
OK	22,146	3,575	3,575	3,871
PA	15,861	3,284	3,132	3,340
TX	47,135	4,440	4,440	6,596
UT	6,276	757	757	757
VA	7,041	1,563	1,465	1,660
WI	6,571	2,150	677	2,234
WV	9,825	982	982	982
WY	10,335	826	826	826
Totals	322,793	47,186	41,153	50,918

As shown in Chapter 4, the estimated annual compliance costs to implement the proposed rule, as described in this RIA, are approximately $-210 million in 2023 and $1,100 million in 2026 (2016$). Compliance costs are negative because in 2023 the EGU compliance costs are negative. 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. This results in delayed retrofit and retirement at EGU facilities, which in turn leads to negative total cost point estimates in 2023.

This RIA uses compliance costs as a proxy for social costs as mentioned in Chapter 4. As shown in Chapter 5, the estimated monetized benefits from reduced $PM_{2.5}$ and ozone concentrations from implementation of the proposed rule are approximately $100 and $500 million in 2023 (2016$, based on a real discount rate of 3 percent). For 2026, the estimated monetized benefits from implementation of the proposed rule are approximately \$9,300 and \$18,000 million (2016\$, based on a real discount rate of 3 percent).

EPA calculates the monetized net benefits of the proposal by subtracting the estimated monetized compliance costs from the estimated monetized benefits in 2023, 2026, and 2030. The benefits include those to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The annual monetized net benefits of the proposed rule in 2023 (in 2016\$) are approximately \$310 and \$710 million using a 3 percent real discount rate. The annual monetized net benefits of the proposed rule in 2026 are approximately \$8,200 and \$17,000 million using a 3 percent real discount rate. The annual monetized net benefits of the rule in 2030 are approximately \$7,700 and \$18,000 million using a 3 percent real discount rate. Table 8-3 presents a summary of the monetized benefits, costs, and net benefits of the proposed rule and the more and less stringent alternatives for 2023. Table 8-4 presents a summary of these impacts for the proposed rule and the more and less stringent alternatives for 2026.

Table 8-5 presents a summary of these impacts for the proposed rule and the more and less stringent alternatives for 2030. These results present an incomplete overview of the effects of the proposal, because important categories of benefits -- including benefits from reducing climate pollution, 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 proposal to be more net beneficial than this table reflects.

Table 8-3. Monetized Benefits, Costs, and Net Benefits of the Proposed Rule and Less and More Stringent Alternatives for 2023 for the U.S. (millions of 2016\$) [a,b]

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
Benefits[c]	\$100 and \$500	\$120 and \$520	\$250 and \$720
Costs[d]	-\$210	-\$170	-\$180
Net Benefits	**\$310 and \$710**	**\$290 and \$690**	**\$430 and \$900**

[a] We focus results to provide a snapshot of costs and benefits in 2023, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted

pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.
[d] The costs presented in this table are 2023 annual estimates for each alternative analyzed. 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.

Table 8-4. Monetized Benefits, Costs, and Net Benefits of the Proposed Rule and Less and More Stringent Alternatives for 2026 for the U.S. (millions of 2016$) [a,b]

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
Benefits[c]	$9,300 and $18,000	$4,300 and $10,000	$9,100 and $19,000
Costs[d]	$1,100	-$49	$1,600
Net Benefits	**$8,200 and $17,000**	**$4,300 and $10,000**	**$7,500 and $17,000**

[a] We focus results to provide a snapshot of costs and benefits in 2026, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.
[d] The costs presented in this table are 2026 annual estimates for each alternative analyzed. 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.

Table 8-5. Monetized Benefits, Costs, and Net Benefits of the Proposed Rule and Less and More Stringent Alternatives for 2030 for the U.S. (millions of 2016$) [a,b]

	Proposed Rule	Less Stringent Alternative	More Stringent Alternative
Benefits[c]	$9,400 and $20,000	$4,300 and $11,000	$9,200 and $21,000
Costs[d]	$1,600	$1,600	$2,200
Net Benefits	**$7,700 and $18,000**	**$2,800 and $9,700**	**$7,000 and $19,000**

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.
[d] The costs presented in this table are 2030 annual estimates for each alternative analyzed. 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.

As part of fulfilling analytical guidance with respect to E.O. 12866, 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 proposed rule, annual benefits and costs are discounted to 2022 at 3 percent and 7 discount rates as directed by OMB's Circular A-4. 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.

For the twenty-year period of 2023 to 2042, the PV of the net benefits, in 2016$ and discounted to 2022, is $220,000 million when using a 3 percent discount rate and $130,000 million when using a 7 percent discount rate. The EAV is $15,000 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 proposed rule can be found in Table 8-6. Estimates in the table are presented as rounded values.

Table 8-6. Summary of Present Values and Equivalent Annualized Values for the 2023-2042 Timeframe for Estimated Monetized Compliance Costs, Benefits, and Net Benefits for the Proposed Rule (millions of 2016$, discounted to 2022)[a,b]

	Benefits		Cost[c]		Net Benefits	
	3%	7%	3%	7%	3%	7%
2023	$500	$450	($210)		$710	$660
2024	$520	$460	$710		-$190	-$240
2025	$530	$470	$710		-$180	-$230
2026	$18,000	$16,000	$1,100		$17,000	$15,000
2027	$19,000	$17,000	$2,000		$17,000	$15,000
2028	$18,000	$16,000	$2,000		$16,000	$14,000
2029	$19,000	$17,000	$2,000		$17,000	$15,000
2030	$20,000	$18,000	$1,600		$18,000	$16,000
2031	$20,000	$18,000	$1,600		$19,000	$16,000
2032	$21,000	$18,000	$2,100		$18,000	$16,000
2033	$20,000	$18,000	$2,100		$18,000	$16,000
2034	$21,000	$18,000	$2,100		$19,000	$16,000
2035	$21,000	$19,000	$2,100		$19,000	$16,000
2036	$21,000	$19,000	$2,100		$19,000	$17,000
2037	$22,000	$19,000	$2,100		$19,000	$17,000
2038	$21,000	$19,000	$1,300		$20,000	$18,000
2039	$22,000	$19,000	$1,300		$20,000	$18,000
2040	$22,000	$19,000	$1,300		$21,000	$18,000
2041	$22,000	$19,000	$1,300		$21,000	$18,000
2042	$22,000	$20,000	$1,300		$21,000	$18,000
PV 2023-2042	**$250,000**	**$150,000**	**$22,000**	**$14,000**	**$220,000**	**$130,000**
EAV 2023-2042	**$17,000**	**$14,000**	**$1,500**	**$1,300**	**$15,000**	**$12,000**

[a] Rows may not appear to add correctly due to rounding.
[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2023 to 2042. The benefits values use the larger of the two benefits estimates presented in Table ES-9 and Table ES-10, as well as for all other years. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.
[c] The costs presented in this table are consistent with the costs presented in Chapter 4. To estimate these annualized costs, 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% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

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