Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review

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Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review

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1.1 Introduction

On November 15, 2021, the Environmental Protection Agency (EPA) published a proposed rule intended to mitigate climate-destabilizing pollution and protect human health by reducing greenhouse gas (GHG) and VOC emissions from the Oil and Natural Gas Industry, specifically the Crude Oil and Natural Gas source category.[1,2] In the November 2021 proposal, the EPA proposed New Source Performance Standards (NSPS) and Emissions Guidelines for Existing Sources (EG) under CAA section 111 which would be codified in 40 CFR part 60 at subpart OOOOb (NSPS OOOOb) and subpart OOOOc (EG OOOOc). The EPA also proposed several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021, under the Congressional Review Act (CRA), disapproving the EPA's final rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review," September 14, 2020 ("2020 Policy Rule"). Lastly in November 2021, the EPA proposed a protocol under the general provisions for optical gas imaging.

On December 6, 2022, the EPA published a supplemental proposed rule that comprised a few distinct actions.[3] First, the EPA updated, strengthened, and/or expanded on the new source performance standards proposed in November 2021 under CAA section 111(b) for GHGs (in the form of methane limitations) and VOC emissions from new, modified, and reconstructed facilities that commenced construction, reconstruction, or modification after November 15, 2021. Second, the EPA updated, strengthened, and/or expanded the presumptive standards proposed in November 2021 as part of the CAA section 111(d) EG for GHGs emissions (in the form of methane limitations) from existing designated facilities that commenced construction, reconstruction, or modification on or before November 15, 2021. Third, EPA established the implementation requirements for states to limit GHGs pollution (in the form of methane

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[1] 86 FR 63110.

[2] The EPA defines the Crude Oil and Natural Gas source category to mean: (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station, commonly referred to as the "city-gate."

[3] 87 FR 74702.

limitations) from existing sources (designated facilities) in the source category under CAA section 111(d).

The purpose of this final rulemaking is to finalize these multiple actions to reduce air emissions from the Crude Oil and Natural Gas source category. First, the EPA finalizes NSPS regulating GHGs in the form of limitations on methane and VOCs for the Crude Oil and Natural Gas source category pursuant the review required by the CAA. Second, the EPA finalizes the first-ever EG under the CAA, for states to follow in developing, submitting, and implementing state plans to establish performance standards to limit GHGs emissions (in the form of methane limitations) from existing sources (designated facilities) in the Crude Oil and Natural Gas source category. Third, the EPA is finalizing several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021, under the Congressional Review Act (CRA), disapproving the EPA's final rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review," Sept. 14, 2020 ("2020 Policy Rule"). Fourth, the EPA is finalizing a protocol under the general provisions for optical gas imaging. These final actions respond to the President's January 20, 2021, Executive Order (E.O.) 13990 titled, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crises," which directed the EPA to consider taking these actions finalized here.

In accordance with E.O. 12866 and E.O. 14094, the guidelines of the Office of Management and Budget Circular A-4 and the EPA's Guidelines for Preparing Economic Analyses (U.S. EPA, 2014), this regulatory impact analysis (RIA) analyzes the nationwide benefits and costs associated with the projected emissions reductions under the for the final rule.[4] The RIA also examines expected economic and environmental justice impacts of the final rule requirements.

1.2 Legal and Economic Basis for this Rulemaking

In this section, we summarize the statutory requirements in the Clean Air Act that serve as the legal basis for the final rule and the economic theory that supports environmental

[4] Circular A-4 was recently revised. The effective date of the revised Circular A-4 (2023) is March 1, 2024, for regulatory analyses received by OMB in support of proposed rules, interim final rules, and direct final rules, and January 1, 2025, for regulatory analyses received by OMB in support of other final rules. For all other rules, Circular A-4 (2003) may be referred to until those dates.

regulation as a mechanism to enhance social welfare. The Clean Air Act requires the EPA to prescribe regulations for new and existing sources. In turn, those regulations attempt to address negative externalities created when private entities fail to internalize the social costs of air pollution.

1.2.1 Statutory Requirements

Clean Air Act section 111, which Congress enacted as part of the 1970 Clean Air Act Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision requires the EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." The EPA has listed more than 60 stationary source categories under this provision. Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for emissions of air pollutants from new sources in the source categories. Under section 111(b), EPA identifies the "best system of emission reduction" (BSER) that has been adequately demonstrated to control emissions of a particular pollutant from a particular type of source and sets a standard for new sources based on the application of that BSER. These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When the EPA establishes NSPS for sources in a source category under CAA section 111(b), the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for hazardous air pollutants (HAP). CAA section 111(d)'s mechanism for regulating existing sources differs from the one that CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish "standards of performance" for the affected sources and contain other measures to implement and enforce those standards.

"Standards of performance" are defined under CAA section 111(a)(1) as standards for emissions that reflect the emission limitation achievable from the "best system of emission reduction," considering costs and other factors, that "the Administrator determines has been adequately demonstrated." Under section 111(d), EPA determines the BSER, but, unlike with new sources under 111(b), the states are the entities that establish performance standards. CAA section 111(d)(1) grants states the authority, in applying a standard of performance, to take into account the source's remaining useful life and other factors.

Under CAA section 111(d), a state must submit its plan to the EPA for approval, and the EPA must approve the state plan if it is "satisfactory." If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for that state. Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved State Implementation Plan (SIP) under the Act.

1.2.2 Market Failure

Many regulations are promulgated to correct market failures, which otherwise lead to a suboptimal allocation of resources within the free market. Air quality and pollution control regulations address "negative externalities" whereby the market does not internalize the full opportunity cost of production borne by society as public goods such as air quality are unpriced.

While recognizing that optimal social level of pollution may not be zero, methane and VOC emissions impose costs on society, such as negative health and welfare impacts, that are not reflected in the market price of the goods produced through the polluting process. For the final regulatory action analyzed in this RIA, the goods produced are crude oil and natural gas. If crude oil and natural gas producers pollute the atmosphere when extracting, processing, and transporting products, the social costs will not be borne exclusively by the polluting firm but rather by society as a whole. Thus, the producer is imposing a negative externality, or a social cost of emissions, on society. The equilibrium market price of crude oil and natural gas may fail to incorporate the full opportunity cost to society of these products. Consequently, absent a regulation on emissions, producers will not internalize the social cost of emissions and social costs will be higher as a result. The final regulation will work towards addressing this market failure by causing affected producers to begin internalizing the negative externality associated with methane and VOC emissions.

1.3 Baseline and Regulatory Requirements

The impacts of regulatory actions are evaluated relative to a baseline that represents the world without the regulatory action. In this case, we present results for the final NSPS OOOOb and EG OOOOc. The baseline for the final rule incorporates changes to regulatory requirements induced by the Congressional Review Act (CRA) resolution that disapproved the 2020 Policy Rule. Throughout this document, we focus the analysis on the requirements that result in quantifiable compliance cost or emissions changes compared to the baseline. We do not analyze the regulatory impacts of all finalized requirements because we lack sufficient data, require additional work to adapt existing data into a coherent analysis framework, or believe the provisions would not result in compliance cost or emissions impacts; see Section for a discussion of provisions for which impacts were not quantified.

Compared to the analyses presented in the RIAs for the November 2021 proposal and the December 2022 supplemental proposal, this analysis reflects new methodologies to estimate and project the universe of affected facilities and their emissions profiles, as well as the cost and emissions impacts of applying control strategies. Most notably, the RIA estimates the cost and emissions impacts of associated gas provisions and requirements for optical gas imaging (OGI) monitoring of flares at controlled storage vessels at well sites, neither of which were quantified in the proposal RIAs. The RIA also leverages region-specific information regarding well site equipment to better characterize local air pollution impacts of the regulation, whereas the proposal RIAs relied on national aggregates. The updated baseline represents the EPA's most recent assessment of the current and future state of the industry absent the requirements of this final rulemaking.

Table 1-1 and Table 1-2 summarize the baseline and finalized standards of performance for the sources with impacts quantified in this RIA.[5] In Table 1-2, requirements in the baseline differ depending on when sources were constructed relative to previous NSPS proposal dates. We define pre- and post-KKK as having construction dates prior to and after January 20, 1984, respectively. The dividing dates for pre- and post-OOOO and pre- and post-OOOOa are August 23, 2011, and September 18, 2015, respectively. The abbreviations used in the table are OGI

[5] See the preamble for a more comprehensive description of the finalized standards.

(optical gas imaging), AVO (auditory, visual, and optical), scfh (standard cubic feet per hour), and scfm (standard cubic feet per minute).

Table 1-1 NSPS OOOOb Emissions Sources, Baseline Requirements, and Requirements under the Final Rule

	Standards of Performance	
Source	**In the Baseline**	**Under the Final Rule**
Fugitive Emissions/Equipment Leaks[a]		
Well Sites		
Wellhead only, single well site	No requirement	Quarterly AVO monitoring
Wellhead only, multiple well site	No requirement	Quarterly AVO monitoring + Semiannual OGI
Single well site with a single price of major equipment and no tank battery	Semiannual OGI	Quarterly AVO monitoring
Multiple well site with a single piece of major equipment, or any site with (1) two or more pieces of major equipment; (2) one piece of major equipment and a tank battery; or (3) a controlled tank battery.	Semiannual OGI	Bimonthly AVO monitoring + Quarterly OGI
Gathering and Boosting Stations	Quarterly OGI	Monthly AVO monitoring + Quarterly OGI
Transmission and Storage Compressor Stations		
Natural Gas Processing Plants	NSPS Subpart VVa	Bimonthly OGI
Pneumatic Pumps		
Well Sites	95% control	Zero emissions[b]
Gathering and Boosting Stations	No requirement	
Pneumatic Controllers[c]		
Well Sites	Natural gas bleed rate no greater than 6 scfh	Zero emissions[d]
Gathering and Boosting Stations		
Transmission and Storage Compressor Stations		
Natural Gas Processing Plants	Zero emissions	
Reciprocating Compressors		
Gathering and Boosting Stations	Rod-packing changeout on fixed schedule	Volumetric flow rate of 2 scfm
Natural Gas Processing Plants		
Transmission and Storage Compressor Stations		
Wet-Seal Centrifugal Compressors		
Gathering and Boosting Stations	No requirement	95% control
Natural Gas Processing Plants	95% control	
Transmission and Storage Compressor Stations		
Liquids Unloading		
Well Sites	No requirement	Zero emissions or best management practices[e]

Source	Standards of Performance	
	In the Baseline	Under the Final Rule
Storage Vessels		
PTE ≥ 6 tpy VOC	95% control, affected facility is the tank	95% control, affected facility is the tank battery
PTE < 6 tpy VOC	No requirement	No requirement
Associated Gas		
Well Sites	No requirement	Route to sales line

[a] Well sites and compressor stations on the Alaska North Slope are subject to Annual OGI monitoring only.
[b] The zero emission standard for pumps applies to sites with electrical power and/or three or more diaphragm pumps. Sites without access to electrical power that have fewer than three diaphragm pumps must route emissions to a control device, provided one is onsite.
[c] Specifically, the affected source is natural gas-driven controllers that vent to the atmosphere.
[d] The zero emissions rate standard does not apply to pneumatic controllers at sites in Alaska for which on site power is not available. Instead, natural gas-driven continuous bleed controllers at those sites are required to achieve bleed rates at or below 6 scfh, while natural gas-driven intermittent bleed controllers are subject to OGI monitoring and repair of emissions from controller malfunctions.
[e] The final regulation requires liquids unloading events to be zero-emitting unless technical infeasibilities exist, in which case the regulation requires that best management practices be adopted.

Table 1-2 EG OOOOc Emissions Sources, Baseline Requirements, and Requirements under the Final Rule

Source	Presumptive Standards of Performance: In the Baseline	Presumptive Standards of Performance: Under the Final Rule
Fugitive Emissions/Equipment Leaks[a,b]		
Well Sites		
Wellhead only, single well site	No requirement	Quarterly AVO monitoring
Wellhead only, multiple well site	No requirement	Quarterly AVO monitoring + Semiannual OGI
Single well site with a single price of major equipment and no tank battery	Pre-OOOOa: No requirement Post-OOOOa: Semiannual OGI	Quarterly AVO monitoring
Multiple well site with a single piece of major equipment, or any site with two or more pieces of major equipment or one piece of major equipment and a tank battery	Pre-OOOOa: No requirement Post-OOOOa: Semiannual OGI	Bimonthly AVO monitoring + Quarterly OGI
Gathering and Boosting Stations	Pre-OOOOa: No requirement Post-OOOOa: Quarterly OGI	Monthly AVO monitoring + Quarterly OGI
Transmission and Storage Compressor Stations	Pre-OOOOa: No requirement Post-OOOOa: Quarterly OGI	Monthly AVO monitoring + Quarterly OGI
Natural Gas Processing Plants	Pre-KKK: No requirement Post-KKK and Pre-OOOO: NSPS Subpart VV Post-OOOO: NSPS Subpart VVa	Bimonthly OGI
Pneumatic Pumps		
Well Sites	Pre-OOOOa: No requirement Post-OOOOa: 95% control	Methane emission rate of zero[b]
Gathering and Boosting Stations	No requirement	Methane emission rate of zero[b]
Pneumatic Controllers[c]		
Well Sites	Pre-OOOO: No requirement Post-OOOO: Natural gas bleed rate no greater than 6 scfh	Methane emission rate of zero[d]
Gathering and Boosting Stations	Pre-OOOO: No requirement Post-OOOO: Natural gas bleed rate no greater than 6 scfh	Methane emission rate of zero[d]
Transmission and Storage Compressor Stations	Pre-OOOOa: No requirement Post-OOOOa: Natural gas bleed rate no greater than 6 scfh	Methane emission rate of zero[d]
Natural Gas Processing Plants	Pre-OOOO: No requirement Post-OOOO: Zero emissions	Methane emission rate of zero
Reciprocating Compressors		
Gathering and Boosting Stations	Pre-OOOO: No requirement Post-OOOO: Rod-packing changeout on fixed schedule	Volumetric flow rate of 2 scfm
Natural Gas Processing Plants	Pre-OOOO: No requirement Post-OOOO: Rod-packing changeout on fixed schedule	Volumetric flow rate of 2 scfm
Transmission and Storage Compressor Stations	Pre-OOOOa: No requirement Post-OOOOa: Rod-packing changeout on fixed schedule	Volumetric flow rate of 2 scfm
Wet-Seal Centrifugal Compressors		
Gathering and Boosting Stations	No requirement	Volumetric flow rate of 3 scfm
Natural Gas Processing Plants	Pre-OOOO: No requirement Post-OOOO: 95% control	Volumetric flow rate of 3 scfm
Transmission and Storage Compressor Stations	Pre-OOOO: No requirement Post-OOOO: 95% control	Volumetric flow rate of 3 scfm
Liquids Unloading		
Well Sites	No requirement	Zero emissions or best management practices[e]

Source	Presumptive Standards of Performance In the Baseline	Under the Final Rule
Storage Vessels		
PTE $\geq$ 20 tpy CH_4	Pre-OOOO: No requirement Post-OOOO: 95% control, affected facility is the tank	95% control, affected facility is the tank battery
PTE < 20 tpy CH_4 and $\geq$ 6 tpy VOC		No requirement
PTE < 20 tpy CH_4 and < 6 tpy VOC	No requirement	
Associated Gas		
Well Sites		
PTE $\geq$ 40 tpy CH_4	No requirement	Route to sales line
PTE < 40 tpy CH_4	No requirement	95% control

[a] Well sites and compressor stations on the Alaska North Slope are subject to Annual OGI monitoring only.
[b] The zero emission standard for pumps applies to sites with electrical power and/or three or more diaphragm pumps. Sites without access to electrical power that have fewer than three diaphragm pumps must route emissions to a control device, provided one is onsite.
[c] Specifically, the affected source is natural gas-driven controllers that vent to the atmosphere.
[d] The zero emissions rate standard does not apply to pneumatic controllers at sites in Alaska for which on site power is not available. Instead, natural gas-driven continuous bleed controllers at those sites are required to achieve bleed rates at or below 6 scfh, while natural gas-driven intermittent bleed controllers are subject to OGI monitoring and repair of emissions from controller malfunctions.
[e] The final regulation requires liquids unloading events to be zero-emitting unless technical infeasibilities exist, in which case the regulation requires that best management practices be adopted.

The net benefits analysis summarized in this RIA reflects a nationwide engineering analysis of compliance cost and emissions reductions, of which there are two main components: activity data and information on control measures. The activity data represents estimates of the counts of affected facilities over time, and the control measure information includes data on costs and control efficiencies for typical facilities. Both components are described briefly below, with more detailed information provided in Section 2.2.

The first component is activity data for a set of representative or model plants for each regulated facility.[6] To project activity data for regulated facilities, we first project activity data for oil and natural gas sites, which include well sites, natural gas processing plants, and compressor stations (gathering and boosting, transmission, and storage). Projections include addition of newly constructed sites and retirement of previously constructed sites, with magnitudes based on a combination of analysis of several data sources and, where necessary, assumptions. Using representative "per-site" factors based on the EPA's Greenhouse Gas

[6] Regulated facilities include well site fugitives (including component emissions and malfunctioning storage vessel flares), gathering and boosting station fugitives, transmission and storage compressor station fugitives, natural gas processing plant equipment leaks, pneumatic pumps, pneumatic controllers, reciprocating compressors, centrifugal compressors, liquids unloading, storage vessels, and associated gas.

Inventory (GHGI) (U.S. EPA, 2021), regulated facilities are apportioned to sites across all industry segments.[7] We assume the per-site factors are fixed over time, so that the projected counts of regulated facilities change in proportion to the projected counts of sites.

The regulated facility projections are combined with information on control options, including capital costs, annual operations and maintenance costs, and control efficiencies. Information on control options is derived from the analysis underpinning the BSER determinations. Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a regulatory regime, multiplying activity data by model plant cost and emissions estimates, differencing from the baseline scenario, and then summing to the desired level of aggregation. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted in production or sold. Where applicable, we present projected compliance costs with and without the projected revenues from product recovery.

For the analysis, we calculate the cost and emissions impacts of the final NSPS OOOOb and EG OOOOc requirements from 2024 to 2038. The initial analysis year is 2024 as the rule will take effect early in that year. The NSPS OOOOb is assumed to take effect immediately and impact sources that commence construction after publication of the December 2022 proposal.[8] We assume that sources begin production, and thus begin generating emissions related to that production, one year after they commence construction, so that sources assumed to be constructed in 2023 first contribute cost and emissions impacts in 2024.[9] We assume the EG OOOOc will take longer to go into effect as states will need to develop implementation plans in response to the rule and have them approved by the Agency. We assume that this process will take four years, and so EG OOOOc impacts will begin in 2028. The final analysis year is 2038, which allows us to present up to 15 post-NSPS-finalization years of regulatory impact estimates.

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[7] Industry segments include production, gathering and boosting, processing, transmission, and storage.

[8] As explained in the preamble to the final rule, NSPS OOOOb would apply to all emissions sources (“affected facilities”) identified in the proposed 40 CFR 60.5365b that commenced construction, reconstruction, or modification after December 6, 2022.

[9] Due to supply chain considerations, NSPS OOOOb allows for longer compliance deadlines for process controllers and pumps; see Sections XI.D.4 (process controllers) and XI.E.2 (pumps). To allow new wells the ability to plan to comply with the associated gas provisions, NSPS OOOOb also allows for a longer compliance deadline for these affected facilities; see Section XI.F.2.d (associated gas) for additional details. We do not quantify the impacts of those extensions in the RIA, but we expect the impacts to be small relative to the overall impacts of the rule due to the limited nature of the extensions.

1.4 Summary of Projected Emissions Reductions and Benefit-Cost Analysis

A summary of the key benefit-cost analysis results is shown below. All dollar estimates are in 2019 dollars. Also, all compliance costs, emissions changes, and benefits are estimated for the years 2024 to 2038 relative to a baseline without the final NSPS OOOOb and EG OOOOc.

Table 1-3 summarizes the emissions reductions associated with the finalized standards over the 2024 to 2038 period for the NSPS OOOOb, the EG OOOOc, and the NSPS OOOOb and EG OOOOc combined. The emissions reductions are estimated by multiplying the source-level emissions reductions associated with each applicable control and facility type by the number of affected sources of that facility type. We present methane emissions in both short tons and CO_2 equivalents (CO_2 Eq.) using a global warming potential (GWP) of 28.[10]

Table 1-3 Projected Emissions Reductions under the Final NSPS OOOOb and EG OOOOc Option, 2024–2038[a,b,c]

	Emissions Changes			
Final	**Methane (million short tons)**	**VOC (million short tons)**	**HAP (million short tons)**	**Methane (million metric tons CO_2 Eq. using GWP=28)**
NSPS OOOOb	23	7.1	0.27	590
EG OOOOc	35	8.6	0.32	890
Total	**58**	**16**	**0.59**	**1,500**

[a] Numbers rounded to two significant digits unless otherwise noted. Totals may not appear to add correctly due to rounding. To convert from short tons to metric tons, multiply the short tons by 0.907. Alternatively, to convert metric tons to short tons, multiply metric tons by 1.102.
[b] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC and HAP emissions.
[c] The control techniques used to meet the storage vessel-related standards are associated with several types of secondary emissions impacts, which may partially offset the direct benefits of this rule. Relative to the direct emission reductions anticipated from this rule, as discussed in Section 3.9, the magnitude of these secondary air pollutant increases is small.

Table 1-4, Table 1-5, and Table 1-6 present results for the NSPS OOOOb, EG OOOOc, and NSPS OOOOb and EG OOOOc combined, respectively. Each table presents the present value (PV) and equivalent annual value (EAV), estimated using discount rates of 2, 3, and 7 percent, of the changes in quantified climate and health benefits, costs, and net benefits, as well

[10] Global warming potential is a measure that allows comparisons of the global warming impacts of different greenhouse gases. Specifically, it is a measure of how much energy the emission of 1 ton of a gas will absorb over a given period of time, relative to the emission of 1 ton of carbon dioxide (CO_2).

as the emissions reductions relative to the baseline.[11,12] These values reflect an analytical time horizon of 2024 to 2038, are discounted to 2021,[13] and presented in 2019 dollars. We present the total compliance costs, the value of product recovery generated by the capture of natural gas, and the net compliance costs, which treats the value of product recovery as an offset to the compliance costs.[14] The table includes consideration of the non-monetized benefits associated with the emissions reductions projected under the final rule.

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[11] Monetized climate effects are presented under a 2 percent near-term Ramsey discount rate, consistent with EPA's updated estimates of the SC-GHG. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. While this RIA was being drafted and reviewed, OMB finalized an update to Circular A-4, in which it recommended the general application of a 2.0 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC-GHG estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG. See Section 3.2 for more discussion.

[12] The EPA has also applied its updated estimates of the social cost of carbon dioxide (SC-CO_2) in an illustrative analysis of potential climate disbenefits from secondary CO_2 emissions associated with control techniques for storage vessels. Given that the estimated climate disbenefits from the CO_2 impacts would at most offset only about 1 percent of the methane benefits, the EPA finds that the summary values shown in this table are a reasonable estimate of the net monetized climate effects of the rule. See Section 3.9 for further discussion.

[13] Costs and benefits are discounted to 2021 to maintain consistency with the November 2021 and December 2022 RIAs.

[14] Almost 90 percent of revenue from the sale of captured natural gas is projected to be earned by operators in the production segment of the industry, where we assume that the operators own the natural gas and will receive the financial benefit from the captured natural gas. The remainder of the captured natural gas is captured within the gathering and boosting, processing, transmission, and storage segments, where operators do not typically own the natural gas they transport; rather, they receive payment for the service they provide. In the RIA, we treat these revenues as an offset to projected compliance costs, while the revenues may also be considered as a benefit of the regulatory action. However, regardless of whether the revenue from capture of natural gas is considered a compliance cost offset or a benefit, the net benefits are equivalent. See Section 2 for further discussion regarding firm incentives for product recovery.

Table 1-4 Projected Benefits, Compliance Costs, and Emissions Reductions for the Finalized NSPS OOOOb, 2024–2038 (million 2019$)

	2 Percent Near-Term Ramsey Discount Rate					
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Climate Benefits[b]	$44,000	$3,400	$44,000	$3,400	$44,000	$3,400
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Ozone Health Benefits[c]	N/A	N/A	N/A	N/A	N/A	N/A
Net Compliance Costs	$5,800	$450	$5,800	$480	$5,300	$580
Compliance Costs	$14,000	$1,100	$13,000	$1,100	$10,000	$1,100
Value of Product Recovery	$7,900	$620	$7,100	$590	$4,700	$520
Net Monetized Benefits[d]	$38,000	$3,000	$38,000	$2,900	$39,000	$2,800
Non-Monetized Benefits	Ozone-related health benefits from reducing 23 million short tons of methane from 2024 to 2038 Benefits to provision of ecosystem services from reducing 23 million short tons of methane, 7.1 million short tons of VOC, and 270 thousand short tons of HAP from 2024 to 2038 $PM_{2.5}$-related health benefits from reducing 7.1 million short tons of VOC from 2024 to 2038 HAP benefits from reducing 270 thousand short tons of HAP from 2024 to 2038					

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane ($SC\text{-}CH_4$) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the $SC\text{-}CH_4$ at the 2 percent near-term Ramsey discount rate. Please see Table 3.4 and 3.5 for the full range of monetized climate benefit estimates.
[c] Due to time and resource limitations, the monetized ozone benefits under the NSPS OOOOb alone were not quantified and are not included in the monetized benefits in this table. See Table 1-6 for an estimate of the monetized ozone benefits under the combined NSPS OOOOb and EG OOOOc combined.
[d] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 3.2 for a discussion of climate effects that are not yet reflected in the $SC\text{-}CH_4$ and thus remain unmonetized and Sections 3.4 through 3.8 for a discussion of other non-monetized benefits.

Table 1-5 Projected Benefits, Compliance Costs, and Emissions Reductions for the Finalized EG OOOOc, 2024–2038 (million 2019$)

	2 Percent Near-Term Ramsey Discount Rate					
	PV	EAV	PV	EAV	PV	EAV
Climate Benefits[b]	$65,000	$5,100	$65,000	$5,100	$65,000	$5,100
	2 Percent Discount Rate		3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV	PV	EAV
Ozone Health Benefits[c]	N/A	N/A	N/A	N/A	N/A	N/A
Net Compliance Costs	$13,000	$1,000	$12,000	$1,000	$8,900	$970
Compliance Costs	$18,000	$1,400	$16,000	$1,400	$12,000	$1,300
Value of Product Recovery	$4,700	$370	$4,200	$350	$2,700	$300
Net Monetized Benefits[d]	$52,000	$4,100	$53,000	$4,100	$56,000	$4,100
Non-Monetized Benefits	Ozone-related health benefits from reducing 35 million short tons of methane from 2024 to 2038 Benefits to provision of ecosystem services from reducing 35 million short tons of methane, 8.6 million short tons of VOC, and 320 thousand short tons of HAP from 2024 to 2038 $PM_{2.5}$-related health benefits from reducing 8.6 million short tons of VOC from 2024 to 2038 HAP benefits from reducing 320 thousand short tons of HAP from 2024 to 2038					

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate. Please see Table 3.4 and 3.5 for the full range of monetized climate benefit estimates.
[c] Due to time and resource limitations, the monetized ozone benefits under the EG OOOOc alone were not quantified and are not included in the monetized benefits in this table. See Table 1-6 for an estimate of the monetized ozone benefits under the combined NSPS OOOOb and EG OOOOc combined.
[d] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 3.2 for a discussion of climate effects that are not yet reflected in the SC-CH_4 and thus remain unmonetized and Sections 3.4 through 3.8 for a discussion of other non-monetized benefits.

Table 1-6 Projected Benefits, Compliance Costs, and Emissions Reductions for the Finalized NSPS OOOOb and EG OOOOc, 2024–2038 (million 2019$)

	2 Percent Near-Term Ramsey Discount Rate					
	PV	EAV	PV	EAV	PV	EAV
Climate Benefits[b]	$110,000	$8,500	$110,000	$8,500	$110,000	$8,500
	2 Percent Discount Rate		3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV	PV	EAV
Ozone Health Benefits[c]	$6,900	$540	$6,000	$510	$3,500	$380
Net Compliance Costs	$19,000	$1,500	$18,000	$1,500	$14,000	$1,600
Compliance Costs	$31,000	$2,400	$29,000	$2,400	$22,000	$2,400
Value of Product Recovery	$13,000	$980	$11,000	$950	$7,400	$820
Net Monetized Benefits[d]	$97,000	$7,600	$97,000	$7,500	$98,000	$7,300
Non-Monetized Benefits	Ozone-related health benefits from reducing 58 million short tons of methane from 2024 to 2038 Benefits to provision of ecosystem services from reducing 58 million short tons of methane, 16 million short tons of VOC, and 590 thousand short tons of HAP from 2024 to 2038 $PM_{2.5}$-related health benefits from reducing 16 million short tons of VOC from 2024 to 2038 HAP benefits from reducing 590 thousand short tons of HAP from 2024 to 2038					

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate. Please see Table 3.4 and 3.5 for the full range of monetized climate benefit estimates.
[c] Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.
[d] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 3.2 for a discussion of climate effects that are not yet reflected in the SC-CH_4 and thus remain unmonetized and Sections 3.4 through 3.8 for a discussion of other non-monetized benefits.

1.5 Organization of RIA

Section 2 describes the projected compliance cost and emissions impacts from the final rule, including the PV and EAV of the projected costs over the 2024 to 2038 period and the associated EAV. Section 3 describes the projected climate benefits, including the PV and EAV of the projected climate benefits and ozone benefits over the 2024 to 2038 period. Section 3 additionally considers the potential beneficial climate, health, and welfare impacts that are not quantified in this RIA. Section 4 describes the economic impact and distributional analysis associated with the final rule. The economic impact and distributional analysis section includes analysis of oil and natural gas market impacts, marginal wells, environmental justice, small entities, and employment. Section 5 compares the projected benefits and compliance cost reductions of this action, as well as a summary of the net benefits with consideration of non-monetized benefits. Section 5 also highlights uncertainties and limitations of the analysis.

1.6 References

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U.S. EPA. (2021). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019 (EPA-430-R-21-005). https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019

2 PROJECTED COMPLIANCE COSTS AND EMISSIONS REDUCTIONS

In this section, we present estimates of the projected engineering compliance costs and emissions reductions associated with the final rule for the 2024 to 2038 period. These estimates are generated by combining model plant-level cost and emissions reductions based on the BSER analysis with activity data projections based on a combination of historical trends and third-party projections. The methods and assumptions used to construct the activity data projections are also documented in this section.

The cost analysis of this RIA is in part based upon on the possibility that reducing emissions from the oil and natural gas sector also produces a financial return via preventing the loss of marketable natural gas. Assuming financially rational producers, standard economic theory suggests that oil and natural gas firms would incorporate all cost-effective improvements, which they are aware of, without government intervention. In general, however, the cost of abating emissions exceeds the potential financial returns from the captured product such that the producer does not abate emissions absent a regulatory requirement. It is possible in certain circumstances that the financial returns from reducing emissions exceed the abatement costs, yet producers still do not capture the natural gas. There may be an opportunity cost associated with the installation of environmental controls (for purposes of mitigating the emission of pollutants) that is not reflected in the control costs. If the environmental investment displaces other investment in productive capital, the difference between the rate of return on the marginal investment displaced by the mandatory environmental investment is a measure of the opportunity cost of the environmental requirement to the regulated entity. However, if firms are not capital constrained, then there may not be any displacement of investment, and the rate of return on other investments in the industry would not be relevant as a measure of opportunity cost. If firms should face higher borrowing costs as they take on more debt, there may be an additional opportunity cost to the firm. To the extent that any opportunity costs are not added to the control costs, the compliance costs presented in this RIA may be underestimated.

2.1 Emissions Sources and Regulatory Requirements Analyzed in this RIA

A series of emissions sources and controls were evaluated as part of the NSPS OOOOb and EG OOOOc rulemaking. Section 2.1.1 provides a basic description of emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic analysis. Section describes the regulatory choices within the final NSPS OOOOb and EG OOOOc that are examined in this RIA. Additional technical detail on the engineering and cost basis of the analysis is available within the preamble, the Technical Support Document (TSD) accompanying the final rulemaking, hereafter referred to as the Final Rule TSD (U.S. EPA, 2023);[15] the Technical Support Document (TSD) for the December 2022 Supplemental Proposal, hereafter referred to as the December 2022 TSD (U.S. EPA, 2022); and the TSD for the November 2021 proposal, hereafter referred to as the November 2021 TSD (U.S. EPA, 2021).

2.1.1 Emissions Sources

The section provides brief descriptions of the emissions sources subject to NSPS OOOOb and EG OOOOc requirements. More detailed modeling, assumptions and other crucial information, and additional technical detail is available in the preamble, the Final Rule TSD, the December 2022 TSD, and the November 2021 TSD.

Fugitive Emissions:[16] There are several potential sources of fugitive emissions throughout the crude oil and natural gas production source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated pressure relief valves (PRVs) or worn gaskets on thief hatches on controlled storage vessels are also potential causes of fugitive emissions. Additional sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves or controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission (e.g., an intermittent pneumatic controller that is venting continuously).

[15] Available at https://www.regulations.gov/ under Docket No. EPA-HQ-OAR-2021-0317.
[16] See Chapter 5 of the December 2022 TSD and Attachments A and B of the Final Rule TSD for more information.

Pneumatic Controllers:[17] Pneumatic controllers are devices used to regulate a variety of physical parameters, or process variables, using air or gas pressure to control the operation of mechanical devices, such as valves. The valves, in turn, control process conditions such as levels, temperatures and pressures. When a pneumatic controller identifies the need to alter a process condition, it will open or close a control valve. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control the valve. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control.

Pneumatic controllers can be categorized based on the emissions pattern of the controller. Some controllers are designed to have the supply-gas provide the required pressure to power the end-device, and the excess amount of gas is emitted. The emissions of this excess gas are referred to as "bleed," and this bleed occurs continuously. Controllers that operate in this manner are referred to as "continuous bleed" pneumatic controllers. These controllers can be further categorized based on the amount of bleed they are designed to have. Those that have a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh) are referred to as "low bleed," and those with a bleed rate of greater than 6 scfh are referred to as "high bleed." Another type of controller is designed to release gas only when the process parameter needs to be adjusted by opening or closing the valve, and there is no vent or bleed of gas to the atmosphere when the valve is stationary. These types of controllers are referred to as "intermittent vent" pneumatic controllers. A third type of controller releases gas to a downstream pipeline instead of the atmosphere. These "closed loop" types of controllers can be used in applications with very low pressure.

Not all pneumatic controllers are natural gas-driven. At sites with electricity, electrically powered pneumatic devices or pneumatic controllers using compressed air can be used. As these devices are not driven by pressurized natural gas, they do not emit any natural gas to the atmosphere. At sites without electricity provided through the grid or on-site electricity generation, solar power can be used in some instances.

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[17] See Chapter 3 of the December 2022 TSD and Chapter 2 of the Final Rule TSD for more information.

Pneumatic Pumps:[18] Most pneumatic pumps fall into two main types: diaphragm pumps, generally used for heat tracing and plunger/piston pumps, generally used for chemical and methanol injection. The pneumatic pump may use natural gas or another gas to drive the pump. These pumps can also be electrically powered. "Non-natural gas-driven" pneumatic pumps can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Because these devices are not natural gas-driven, they do not directly release natural gas or methane emissions. However, these systems have other energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power an air control system.

Reciprocating Compressors:[19] In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder.

Centrifugal Compressors:[20] Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Some centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The

[18] See Chapter 4 of the December 2022 TSD and Chapter 3 of the Final Rule TSD for more information.
[19] See Chapter 7 of the November 2021 TSD for more information.
[20] See Chapter 2 of the December 2022 TSD for more information.

circulated oil entrains and adsorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process. Off gassing of entrained natural gas from wet seal centrifugal compressors is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process. Some centrifugal compressors utilize dry seal systems. Dry seal systems minimize leakage by using the opposing force created by hydrodynamic grooves and springs.

Storage vessels:[21] Storage vessels, or storage tanks, in the oil and natural gas sector are used to hold a variety of liquids, including crude oil, condensates, and produced water. Many facilities operate a group of storage vessels, sometimes in series but most often in parallel, used to store the same oil or condensate streams. This group of tanks used to store a common fluid is typically called a tank battery.

Underground crude oil contains many light hydrocarbon gases in solution. When oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons are removed through a series of high-pressure and low-pressure separators. The oil (or condensate or water) from the separator is then directed to a tank battery where it is stored before being shipped off-site. Some light hydrocarbon gases remain dissolved in the oil, condensate, or water because the separator operates at pressures above atmospheric pressure. These dissolved hydrocarbon gases are released from the liquid as vapors, commonly referred to as flash gas, when stored at atmospheric pressures in the tank batteries. Typically, the larger the operating pressure of the separator, the more flash emissions will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions. Lighter crude oils and condensate generally flash more hydrocarbons than heavier crude oils.

In addition to flash gas losses, other hydrocarbons may be emitted from the storage vessels due to working and breathing (or standing) losses. Working losses occur when vapors are displaced due to the emptying and filling of tank batteries. When the liquid level in the tank is lowered, ambient air is drawn into the tank's headspace. Some hydrocarbons from the liquid will volatilize into the headspace to reach equilibrium with the new headspace gas. When the liquid level in the tank is increased, it will expel the saturated headspace gas into the atmosphere.

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[21] See Chapter 6 of the November 2021 TSD for more information.

Breathing losses are the release of gas associated with daily temperature fluctuations when the liquid level remains unchanged. As temperatures drop (or atmospheric pressure increases), gas in the headspace contracts, drawing in ambient air. Again, hydrocarbons volatilize into this new gas due to equilibrium effects. As the temperature rises (or atmospheric pressure falls), the gas in the tank's headspace expands, expelling a portion of the hydrocarbon-saturated gas. Working losses increase relative to the "turnover rate" (throughput rate divided by the tank capacity) and are typically much greater than breathing losses.

Liquids Unloading:[22] In new natural gas wells, there is generally sufficient reservoir pressure/gas velocity to facilitate the flow of water and hydrocarbon liquids through the well head and to the separator to the surface along with produced gas. In mature gas wells, the accumulation of liquids in the wellbore can occur when the bottom well pressure/gas velocity approaches the average reservoir pressure (i.e., volumetric average fluid pressure within the reservoir across the areal extent of the reservoir boundaries). This accumulation of liquids can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production (i.e., liquids loading), removal of fluids (i.e., liquids unloading) is required to maintain production. These gas wells therefore often need to remove or "unload" the accumulated liquids so that gas production is not inhibited.

The choice of what liquids unloading technique to employ is based on a well-by-well and reservoir-by-reservoir analysis. To address the complex science and engineering considerations to cover well unloading requirements, many differing technologies, techniques, and practices have been developed to address an individual well's characteristics of the well to manage liquids and maintain production of the well. At the onset of liquids loading, techniques that rely on the reservoir energy are typically used. Eventually a well's reservoir energy is not sufficient to remove the liquids from the well and it is necessary to add energy to the well to continue production. Owners and operators can choose from several techniques to remove the liquids, including manual unloading, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps, intermittent unloading, gas lift (e.g., use of a plunger lift), foam agents and wellhead compression. Each of these methods/procedures removes accumulated liquids and thereby maintains or restores gas production. Although the unloading method employed by an

[22] See Chapter 11 of the November 2021 TSD for more information.

owner or operator can itself be a method that mitigates/eliminates venting of emissions from a liquids unloading event, dictating a particular method to meet a particular well's unloading needs is a production engineering decision.

Equipment Leaks at Gas Plants:[23] The primary sources of equipment leak emissions from natural gas processing plants are pumps, valves, and connectors. The major cause of equipment leak emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. For pumps, emissions are often a result of a seal failure. The large number of valves, pumps, and connectors at natural gas processing plants means emissions from these components can be significant.

Common classifications of equipment at natural gas processing facilities include components in VOC service and in non-VOC service. "In VOC service" is defined as a component containing or in contact with a process fluid that is at least 10 percent VOC by weight or a component "in wet gas service," which is a component containing or in contact with field gas before extraction. "In non-VOC service" is defined as a component in methane service (at least 10 percent methane) that is not also in VOC service.

The most common technique to reduce emissions from equipment leaks is to implement a leak detection and repair (LDAR) program. Implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure for the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. The effectiveness of an LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks.

Associated Gas:[24] Associated gas is natural gas that is generated by oil wells (at wellheads). The natural gas is either naturally occurring in a discrete gaseous phase within the liquid hydrocarbon or is released from the liquid hydrocarbons by separation. In many areas, a natural gas gathering infrastructure may be at capacity or unavailable. In such cases, if there is

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[23] See Chapter 10 of the November 2021 TSD for more information.

[24] See Chapter 13 of the November 2021 TSD, Chapter 6 of the December 2022 TSD, and Chapter 4 of the Final Rule TSD for more information.

not another beneficial use of the gas at the site (e.g., as fuel) the collected natural gas is either flared or vented directly to the atmosphere.

Since unprocessed natural gas is primarily composed of methane, with additional amounts of carbon dioxide (CO_2) and volatile organic compounds (VOC), including some hazardous air pollutant (HAP) like benzene, toluene, ethylbenzene, and xylene, these air pollutants are vented to the atmosphere from venting associated gas. If flared, the methane and VOC emissions are reduced, but carbon monoxide (CO), CO_2, nitrogen oxides (NO_X), and the HAP formaldehyde would be generated. Several analyses conducted by the EPA have indicated that associated gas significantly contributes to methane and VOC emissions.

Options to mitigate emissions from associated gas in order of environmental and resource conservation benefit include:

- Capturing the associated gas from the separator and routing the gas into a gas gathering flow line or collection system;
- Beneficially using the associated gas (e.g., onsite use, natural gas liquid processing, electrical power generation, gas to liquid);
- Reinjecting for enhanced oil recovery; and
- Flaring.

Except for flaring, the site-specific variabilities associated with the application of these control options are significant.

2.1.2 Regulatory Requirements

Table 2-1 and Table 2-2 summarize the baseline and finalized standards of performance for the sources with impacts quantified in this RIA.[25] In Table 2-2, requirements in the baseline differ depending on when sources were constructed relative to previous NSPS proposal dates. We define pre- and post-KKK as dates prior to and after January 20, 1984, respectively. The dividing dates for pre- and post-OOOO and pre- and post-OOOOa are August 23, 2011, and September 18, 2015, respectively. The abbreviations used in the table are OGI (optical gas

[25] See the preamble for a more comprehensive description of the final standards.

imaging), AVO (auditory, visual, and optical), scfh (standard cubic feet per hour), and scfm (standard cubic feet per minute).

Table 2-1 NSPS OOOOb Emissions Sources, Baseline Requirements, and Finalized Requirements

Source	Standards of Performance: In the Baseline	Standards of Performance: Under the Final Rule
Fugitive Emissions/Equipment Leaks[a]		
Well Sites		
Wellhead only, single well site	No requirement	Quarterly AVO monitoring
Wellhead only, multiple well site	No requirement	Quarterly AVO monitoring + Semiannual OGI
Single well site with a single price of major equipment and no tank battery	Semiannual OGI	Quarterly AVO monitoring
Multiple well site with a single piece of major equipment, or any site with (1) two or more pieces of major equipment; (2) one piece of major equipment and a tank battery; or (3) a controlled tank battery.	Semiannual OGI	Bimonthly AVO monitoring + Quarterly OGI
Gathering and Boosting Stations	Quarterly OGI	Monthly AVO monitoring + Quarterly OGI
Transmission and Storage Compressor Stations		
Natural Gas Processing Plants	NSPS Subpart VVa	Bimonthly OGI
Pneumatic Pumps		
Well Sites	95% control	Zero emissions[b]
Gathering and Boosting Stations	No requirement	
Pneumatic Controllers[c]		
Well Sites	Natural gas bleed rate no greater than 6 scfh	Zero emissions[d]
Gathering and Boosting Stations		
Transmission and Storage Compressor Stations		
Natural Gas Processing Plants	Zero emissions	
Reciprocating Compressors		
Gathering and Boosting Stations	Rod-packing changeout on fixed schedule	Volumetric flow rate of 2 scfm
Natural Gas Processing Plants		
Transmission and Storage Compressor Stations		
Wet Seal Centrifugal Compressors		
Gathering and Boosting Stations	No requirement	95% control
Natural Gas Processing Plants	95% control	
Transmission and Storage Compressor Stations		
Liquids Unloading		
Well Sites	No requirement	Zero emissions or best management practices[e]

Storage Vessels		
PTE ≥ 6 tpy VOC	95% control, affected facility is the tank	95% control, affected facility is the tank battery
PTE < 6 tpy VOC	No requirement	No requirement
Associated Gas		
Well Sites	No requirement	Route to sales line

[a] Well sites and compressor stations on the Alaska North Slope are subject to Annual OGI monitoring only.
[b] The zero emission standard for pumps applies to sites with electrical power and/or three or more diaphragm pumps. Sites without access to electrical power that have fewer than three diaphragm pumps must route emissions to a control device, provided one is onsite.
[c] Specifically, the affected source is natural gas-driven controllers that vent to the atmosphere.
[d] The zero emissions rate standard does not apply to pneumatic controllers at sites in Alaska for which on site power is not available. Instead natural gas-driven continuous bleed controllers at those sites are required to achieve bleed rates at or below 6 scfh, while natural gas-driven intermittent bleed controllers are subject to OGI monitoring and repair of emissions from controller malfunctions.
[e] The final regulation requires liquids unloading events to be zero-emitting unless technical infeasibilities exist, in which case the regulation requires that best management practices be adopted.

Table 2-2 EG OOOOc Emissions Sources, Baseline Requirements, and Finalized Requirements

Source	Presumptive Standards of Performance: In the Baseline	Presumptive Standards of Performance: Under the Final Rule
Fugitive Emissions/Equipment Leaks[a,b]		
Well Sites		
Wellhead only, single well site	No requirement	Quarterly AVO monitoring
Wellhead only, multiple well site		Quarterly AVO monitoring + Semiannual OGI
Single well site with a single price of major equipment and no tank battery	Pre-OOOOa: No requirement Post-OOOOa: Semiannual OGI	Quarterly AVO monitoring
Multiple well site with a single piece of major equipment, or any site with two or more pieces of major equipment or one piece of major equipment and a tank battery	Pre-OOOOa: No requirement Post-OOOOa: Semiannual OGI	Bimonthly AVO monitoring + Quarterly OGI
Gathering and Boosting Stations	Pre-OOOOa: No requirement Post-OOOOa: Quarterly OGI	Monthly AVO monitoring + Quarterly OGI
Transmission and Storage Compressor Stations		
Natural Gas Processing Plants	Pre-KKK: No requirement Post-KKK and Pre-OOOO: NSPS Subpart VV Post-OOOO: NSPS Subpart VVa	Bimonthly OGI
Pneumatic Pumps		
Well Sites	Pre-OOOOa: No requirement Post-OOOOa: 95% control	Methane emission rate of zero[b]
Gathering and Boosting Stations	No requirement	
Pneumatic Controllers[c]		
Well Sites	Pre-OOOO: No requirement Post-OOOO: Natural gas bleed rate no greater than 6 scfh	Methane emission rate of zero[d]
Gathering and Boosting Stations		
Transmission and Storage Compressor Stations	Pre-OOOOa: No requirement Post-OOOOa: Natural gas bleed rate no greater than 6 scfh	
Natural Gas Processing Plants	Pre-OOOO: No requirement Post-OOOO: Zero emissions	Methane emission rate of zero
Reciprocating Compressors		
Gathering and Boosting Stations	Pre-OOOO: No requirement Post-OOOO: Rod-packing changeout on fixed schedule	Volumetric flow rate of 2 scfm
Natural Gas Processing Plants		
Transmission and Storage Compressor Stations	Pre-OOOOa: No requirement Post-OOOOa: Rod-packing changeout on fixed schedule	
Wet Seal Centrifugal Compressors		
Gathering and Boosting Stations	No requirement	Volumetric flow rate of 3 scfm
Natural Gas Processing Plants	Pre-OOOO: No requirement Post-OOOO: 95% control	
Transmission and Storage Compressor Stations		
Liquids Unloading		

Well Sites	No requirement	Zero emissions or best management practices[e]
Storage Vessels		
PTE ≥ 20 tpy CH_4	Pre-OOOO: No requirement Post-OOOO: 95% control, affected facility is the tank	95% control, affected facility is the tank battery
PTE < 20 tpy CH_4 and ≥ 6 tpy VOC		No requirement
PTE < 20 tpy CH_4 and < 6 tpy VOC	No requirement	
Associated Gas		
Well Sites		
PTE ≥ 40 tpy CH_4	No requirement	Route to sales line
PTE < 40 tpy CH_4	No requirement	95% control

[a] Well sites and compressor stations on the Alaska North Slope are subject to Annual OGI monitoring only.
[b] The zero emission standard for pumps applies to sites with electrical power and/or three or more diaphragm pumps. Sites without access to electrical power that have fewer than three diaphragm pumps must route emissions to a control device, provided one is onsite.
[c] Specifically, the affected source is natural gas-driven controllers that vent to the atmosphere.
[d] The zero emissions rate standard does not apply to pneumatic controllers at sites in Alaska for which on site power is not available. Instead, natural gas-driven continuous bleed controllers at those sites are required to achieve bleed rates at or below 6 scfh, while natural gas-driven intermittent bleed controllers are subject to OGI monitoring and repair of emissions from controller malfunctions.
[e] The final regulation requires liquids unloading events to be zero-emitting unless technical infeasibilities exist, in which case the regulation requires that best management practices be adopted.

There are finalized requirements that we do not attempt to quantify regulatory impacts for in this RIA. We do not attempt to quantify the impacts of the super-emitter response program *per se* due to the unpredictable nature of super-emission events, resulting in a lack of specific data on their frequency, intensity, and cost to mitigate. Moreover, there is a lack of specific information on how often third parties would conduct monitoring activities, what those activities would entail, how often they would detect super-emitters, how often those detections would provide sufficient and timely information for companies to respond. We do, however, attempt to quantify the impacts of a regulatory requirement to monitor flares during OGI inspections, though we limit our analysis to controlled storage vessels because we believe the available data is sufficient for that emissions source to conduct meaningful quantification. Process emissions from inactive or malfunctioning flares represent a significant source of super-emission events (Cusworth et al., 2021), and so our assessment of the flare monitoring requirements can be viewed as capturing a portion of the impacts that the super-emitter response program might otherwise have.

In addition, we also do not attempt to quantify regulatory impacts for storage vessel control requirements at centralized production facilities (CPFs) and in the gathering and boosting segment, or dry seal centrifugal compressor requirements in any segment. In both instances, we lack sufficient data to conduct an informative analysis. However, given the relatively small source-level impact estimates for storage vessel control requirements at well sites (see Table 5-6), we expect the impacts from the storage vessels provisions at CPFs and in the gathering and boosting segment to be small relative to the overall impacts of the final rule.

Finally, we also do not account for instances in which all or some sources in Alaska are subject to different requirements than those in the rest of the country, both in the baseline due to previous rulemakings and in this final rule. See Section 5.2 for additional discussion.

2.2 Methodology

The compliance cost and emissions reductions analysis summarized in this RIA reflects a nationwide engineering analysis of which there are two main components: activity data and information on control measures. The activity data represents estimates of the counts of affected facilities over time, and the control measure information includes data on costs and control efficiencies for typical facilities.

The first component is activity data for a set of representative (or model) plants for each regulated facility.[26] To project activity data for regulated facilities, we first project activity data for oil and natural gas sites, which include well sites, natural gas processing plants, and compressor stations (gathering and boosting, transmission, and storage). Projections include addition of newly constructed sites and retirement of previously constructed sites, with magnitudes based on a combination of analysis of several data sources and, where necessary, sensible assumptions. Using representative per-site factors generated from the GHGI, regulated facilities are apportioned to sites across all industry segments.[27] We assume the per-site factors are fixed over time, so that the projected counts of regulated facilities change in proportion to the projected counts of sites. The regulated facility projections are combined with information on control options, including capital costs, annual operations and maintenance costs, and control efficiencies. Information on control options is derived from the analysis underpinning the BSER determinations. Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a regulatory regime, multiplying activity data by model plant cost and

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[26] Regulated facilities include well site fugitives (including component emissions and malfunctioning storage vessel flares), gathering and boosting station fugitives, transmission and storage compressor station fugitives, natural gas processing plant equipment leaks, pneumatic pumps, pneumatic controllers, reciprocating compressors, centrifugal compressors, liquids unloading, storage vessels, and associated gas.

[27] Industry segments include production, gathering and boosting, processing, transmission, and storage.

emissions estimates, differencing from the baseline scenario, and then summing to the desired level of aggregation. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted in production or sold. Where applicable, we present projected compliance costs with and without the projected revenues from product recovery.

For the analysis, we calculate the cost and emissions impacts of the final NSPS OOOOb and EG OOOOc from 2024 to 2038. The initial analysis year is 2024 as the rule will take effect early in that year. The NSPS OOOOb is assumed to take effect immediately and impact sources that commence construction after publication of the December 2022 proposal. We assume that sources begin production, and thus begin generating emissions related to that production, one year after they commence construction, so that sources assumed to be constructed in 2023 first contribute cost and emissions impacts in 2024.[28] We assume the EG OOOOc will take longer to go into effect as states will need to develop implementation plans in response to the rule and have them approved by the Agency. We assume that this process will take four years, and so EG OOOOc impacts will begin in 2028. The final analysis year is 2038, which allows us to present up to 15 post-finalization years of regulatory impact estimates.

While it would be desirable to analyze impacts beyond 2038, limited information available to model long-term changes in practices and equipment use in the oil and natural gas industry make the choice of a longer time horizon currently infeasible with the data and modeling currently available to the EPA. In a dynamic industry like oil and natural gas, technological progress is likely to change control methods to a greater extent over a longer time horizon, creating more uncertainty about impacts of the NSPS OOOOb and the EG OOOOc. For example, the current analysis does not include potential fugitive emissions controls employing remote sensing technologies currently under development.

[28] Due to supply chain considerations, NSPS OOOOb allows for longer compliance deadlines for process controllers and pumps; see Sections XI.D.4 (process controllers) and XI.E.2 (pumps). To allow new wells the ability to plan ahead to comply with the associated gas provisions, NSPS OOOOb also allows for a longer compliance deadline for these affected facilities; see Section XI.F.2.d (associated gas) for additional details. We do not quantify the impacts of those extensions in the RIA, but we expect the impacts to be small relative to the overall impacts of the rule due to the limited nature of the extensions.

2.2.1 Activity Data Projections

To construct the activity data projections used in this analysis, we rely on historical data from the GHGI,[29] industry data collected by the EPA through an information collection request (ICR) distributed in 2016 (hereafter, "2016 ICR"), information from the private firm Enverus that provides energy sector data and analytical services,[30] the Department of Homeland Security's Homeland Infrastructure Foundation-Level Data (HIFLD),[31] and projections from the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO).[32] Our projections follow a two-step procedure. First, we construct projected counts of oil and natural gas sites, such as well sites, compressor stations, and processing plants, that contain or are themselves facilities affected by the regulations. Second, using per-well factors, we build upon the site projections to estimate the counts of these affected facilities. The details of these calculations are described by site/regulated facility type below.

In addition to sites and affected facilities, there is a third category of activity data that we track. When comparing a new regulatory regime, such as this final rule, to the baseline scenario, a subset of affected facilities is assumed to take action to comply with regulatory requirements: we refer to these facilities as "incrementally impacted facilities." In Section 2.2.1.3 below, we provide a table of incrementally impacted facility counts for the final rule relative to the baseline.

2.2.1.1 Projected Oil and Natural Gas Sites

There are three types of sites in our analysis of projected facilities: well sites, compressor stations, and natural gas processing plants. Compressor stations are further subdivided into sites located in different segments of the natural gas sector, that is, the gathering and boosting, transmission, and storage segments. For each site type, we generate annual projections of cumulative and new counts for four different vintage bins: the first vintage (V1) represents sites constructed prior to NSPS OOOO, the second vintage (V2) represents sites constructed after

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[29] See Methodology Annexes 3.5 and 3.6 at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2019-ghg. Activity data is presented in Tables 3.5-5 and 3.6-7, respectively.

[30] Enverus: https://www.enverus.com/.

[31] Homeland Infrastructure Foundation-Level Data (HIFLD): https://hifld-geoplatform.opendata.arcgis.com/.

[32] EIA AEO: https://www.eia.gov/outlooks/aeo/.

NSPS OOOO but prior to NSPS OOOOa, the third vintage (V3) represents sites constructed after NSPS OOOOa but prior to NSPS OOOOb, and the fourth vintage (V4) represents sites constructed after NSPS OOOOb. Within V3, sites are further subdivided into sites constructed after NSPS OOOOa through the base year (2019) and 3 additional vintages representing sites assumed to be constructed in each year from 2020 through 2023. V4 is subdivided into separate vintages for each year from 2024, when the NSPS OOOOb is assumed to take effect, through 2038. In the case of well sites only, V1 is subdivided into sites constructed prior to 2000 and sites constructed from 2000 on to capture differences in the characteristics of well sites constructed in different time periods.

There are two countervailing forces that impact the overall trajectory of our estimated sites beyond the base year: the rate at which new sites are constructed and the rate at which sites retire (or cease operation). In our analysis, counts of newly constructed sites are based on either analysis of historical trends from the GHGI (compressor stations), GHGI and the Department of Homeland Security's Homeland Infrastructure Foundation-Level Data (HIFLD) (processing plants), or projections from AEO (well sites). Estimates of retirement rates are based on analysis of Enverus data (well sites) and assumptions underlying analysis submitted in response to the 2018 NSPS OOOOa Policy Reconsideration proposal (processing plants and compressor stations);[33] along with new site counts, those rates are summarized in Table 2-3. To avoid sites having implausibly short lifespans in the analysis, we assume site retirements only apply to well sites that are at least five years old and processing plants and compressor stations in V1 (pre-OOOO).

[33] See page 4 of Appendix D of Docket ID No. EPA-HQ-OAR-2017-0757-0002.

Table 2-3 Assumed Retirement Rates and Annual New Site Counts by Site Type

Type of Site	New Site Counts in Each Year	Annual Retirement Rate as a Percentage of Existing Stock
Well Sites	14,000 – 28,000	-
Greater than 15 barrels of oil equivalent (boe) per day	-	0%
3–15 boe per day		
Oil	-	1.6%
Gas	-	1%
Less than 3 boe per day		
Oil	-	6.7%
Gas	-	4.4%
Compressor Stations		
Gathering and Boosting	439	1%
Transmission	102	1%
Storage	2	1%
Natural Gas Processing Plants	7	1%

Our projections of the cumulative counts of sites for each vintage are illustrated in Figure 2-1. While the projected total counts of wells are relatively stable over the analysis horizon, the projected total counts of well sites decline significantly, as older, smaller sites are displaced by newer, larger sites. The total counts of natural gas processing plants and storage compressor stations change slightly over time, due to very few assumed annual additions and retirements. For gathering and boosting and transmission compressor stations, the total number of sites increase significantly over the analysis horizon. Below, we describe how those trajectories are generated for each site type.

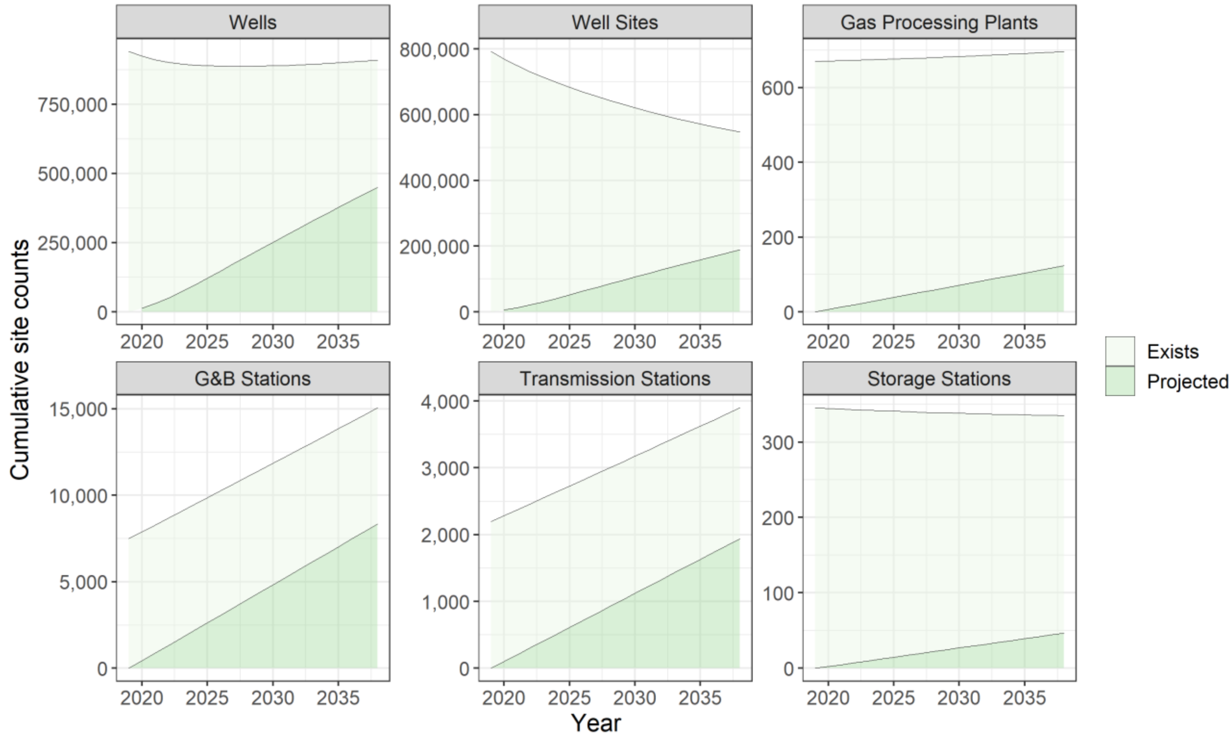

Figure 2-1 Projections of Cumulative Site Counts by Site Type and Vintage

(a) Well Sites

The dataset used to characterize the base year (2019) population of oil and natural gas well sites is developed from data provided by Enverus, a private firm focused on the energy industry that provides data and analytical services. The dataset includes two types of entities: wells and leases. Whether a well is represented as its own entity or as part of a lease depends on the state in which the well is located, as reporting requirements differ across state agencies. The columns in the dataset include entity identifiers, well site identifiers (for wells), locations, completion and initial production dates, well counts (for leases), and natural gas and liquids production levels. We restricted the dataset to onshore wells with positive production values in 2019. The base year is chosen as 2019 to maintain consistency with the proposals and avoid reflected anomalous behavior resulting from the Covid-19 pandemic.

Using the base year dataset, we perform a series of steps to convert from well- and lease-level data to site-level data. First, we aggregate the well-level data into site-level data using the Enverus-provided well site identifiers when available. Each data point includes information on site location, date (based on the most recent well completion), count of oil wells, count of gas wells, and liquids and gas production levels. Wells are categorized as oil or natural gas based on the wells' gas-to-oil ratios (GOR).[34] For wells without site identifiers and leases, we track the same information, but at the well or lease level. For each entity (site, well, or lease), we project production forward through the end of the analysis horizon using simple decline rate assumptions based on analysis of historical production data. Decline rates are estimated using well-level Enverus production data from 2010–2020. For each well and production year, decline percentages for oil/condensate and gas production are calculated as the production level in the next year less the production in the current year, divided by current production. We then calculate median decline rates for four production rate bins, resulting in the decline rate assumptions in Table 2-4.

Table 2-4 Decline Rate Assumptions by Production Type and Rate

	Production Rate Bin (barrels of oil equivalents/day, or BOE/d)			
Production Type	Greater than 100	15–100	3–15	Less than 3
Oil/Condensate	35%	18%	11%	10%
Gas	26%	13%	9%	7%

Using the projections, we aggregate entities into representative groups for each year (2019–2038). For well sites, each group characterized by a unique combination of state, region,[35] vintage (based on the bins described in the previous section), site type (oil or natural gas), well count bin (single well or multi-well), base year production rate bin, and current year production rate bin.[36] Each group includes total counts of sites, oil and natural gas wells, and oil and natural gas production. Likewise, the well and lease entities for which we do not have site identifiers are aggregated analogously, but without well count bins. To fill that gap, we apportion the well counts and production levels of the well/lease entity groups into single and multi-well bins based on regional- or state-level proportions derived from the subset of data with well site identifiers,

[34] If GOR > 100,000 mcf per bbl, then the well is designated as a gas well, otherwise, it is designated as an oil well.

[35] Well sites are mapped from American Association of Petroleum Geologists (AAPG) Geologic Provinces (see https://ngmdb.usgs.gov/Geolex/stratres/provinces) to the supply regions from EIA's National Energy Modeling System's Oil and Gas Supply Module (OGSM) (see Figure 1-2 in the linked report from https://www.eia.gov/analysis/pdfpages/m063index.php). Our analysis regions are nearly the same as the OGSM supply regions, except all sites in Alaska are grouped into a single region. The full set of regions and their abbreviations are Alaska (AK), Gulf Coast (GC), Midcontinent (MC), Northeast (NE), Northern Plains (NP), Rocky Mountain (RM), Southwest (SW), and West Coast (WC).

[36] Sites are grouped into the four production rate bins, based on the average BOE/d per well at the site, described in Table 2-4.

stratifying over site types, vintage bins, and initial production rate bins.[37] To complete the imputation, we calculate the number of sites within each group by dividing well counts by national average estimates of the number of wells per site. The two sets of groups are then combined to form one cohesive dataset with projections of production for a collection of representative well site groups.[38]

In addition to the projection of the base year dataset, we also implement a series of steps to construct projections for well sites assumed to be constructed in years beyond 2019. First, we implement the well site grouping procedure just described, but restricted to sites with completion dates in a recent vintage (2018). Our operating assumption is that future sites will be distributed similarly across locations, site types, well count bins, and production rate bins as sites recently completed. We then use the representative grouping to distribute AEO2022 nationwide-projections of new wells drilled from 2020 to 2038 based on the relative proportions of wells in each group, with production for each vintage projected through 2038.

The last step in the well site projection procedure is to apply the retirement percentages presented in Table 2-3. The retirement percentages differ by production bin and site type and are otherwise uniformly applied across groups regardless of other characteristics, such as location.[39] Only low production sites (less than 15 BOE/d/well) are assumed to retire, and the bulk of retirements come from sites with very low production (less than 3 BOE/d/well).

(a) Compressor Stations

[37] Wells in Kansas, Michigan, Mississippi, Nebraska, and Oklahoma are apportioned based on region-level data, since all data for those states is provided at the lease level. Wells in California are apportioned based on state-level data, since most wells in that state have pad identifiers. A small number of wells in Alabama, Arizona, Florida, Louisiana, Missouri, Nevada, Ohio, Oregon, Pennsylvania, Texas, West Virginia, and Wyoming do not have pad identifiers: those wells are assigned as single-well pads.

[38] The dataset, along with the analysis code used to estimate impacts, can be found in the docket.

[39] Retirement percentages are estimated using well-level Enverus production data from 2010–2020. For a subset of those years (2012–2018), we identify wells that previously had production, but have no recorded oil or gas production records for 2 consecutive years, as retired. Retirement percentages are then calculated by dividing the count of retired wells in each year by the total count of producing wells from the previous year. The retirement rate percentage assumptions result from averaging the estimated retirement rates over all years.

We project compressor stations for three segments (gathering and boosting, transmission, and storage) using data from the GHGI; the approach for all three segments is analogous.[40] The first step is to estimate the number of stations in the base year, 2019. We assume that the number of stations in 2011 are all V1 stations (pre-OOOO). To get the counts of V1 stations in subsequent years, including the base year, we apply the relevant annual retirement rates to the 2011 station counts. The number of V2 stations (post-OOOO, pre-OOOOa) in 2019 is estimated by subtracting the estimated number of V1 stations in 2015 from the total station counts from 2015. The number of V3 stations (post-OOOOa) in 2019 is estimated by subtracting the estimated number of V1 and V2 stations in 2019 from the total number of stations.

To project the number of new stations constructed in the years after the base year, we calculate a historical average number of new stations per year over a recent period (as presented in Table 2-3) and apply it uniformly across all years. Specifically, we divide the calculated number of V3 stations in 2019 and divide it by four, as the first V3 stations are assumed to be operating in 2016. This yields an estimate of the average number of V3 stations added per year through the base year, and we assume new stations are added at that same rate beyond the base year. New stations assumed to be operating in 2020–2023 are assigned to V3, while all estimated new stations beyond 2023 are assigned to V4.

The final step is to project station counts for those existing in the base year and combine those projections with the new construction projections. This results in a set of projections in which V1 station counts decline over the analysis horizon due to retirements and V2 station counts are uniform over the analysis horizon. V3 station counts are also uniform over the analysis horizon, but they are split across five vintages (2016 to 2019, 2020, 2021, 2022, and 2023), with the last four equal to the average number of new stations described above. Finally, V4 station counts are equal to the new station estimates in all vintage/year combinations from 2024 to 2038.

(b) Natural Gas Processing Plants

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[40] Station counts are extracted from the following rows: *Yard Piping* (gathering and boosting) and *Station + Compressor Fugitive Emissions* (transmission and storage).

To construct base year activity data counts for natural gas processing plants, we leverage data from both the GHGI and HIFLD.[41] The estimates of the counts of V1 and V2 plants are generated using the same process as for compressor stations: the 2011 count of plants are assigned to V1, and the V2 count of plants in 2015 is estimated to be the 2015 count from the GHGI minus the estimated count of V1 plants in 2015 after the annual retirement rates are applied. We use the HIFLD as a source of 2020 plant counts since plant counts have been fixed in the GHGI in recent years due to lack of data, and the latest update date for HIFLD is from October 2020. Estimates for the count of V3 plants in 2020 are then calculated using the 2020 total plant estimate and subtracting V1 (after applying retirements) and V2 plant counts. The estimated number of new plants in each year beyond the base year is then calculated by dividing the number of V3 plants in 2020 by the number of years (5) assumed to have passed since the first NSPS OOOOa-affected facilities were constructed. That estimate is used to calculate the number of V3 plants in the base year by subtracting it from the 2020 count, as well as to populate the counts of plants for all vintages and years beyond the base year.

2.2.1.2 Affected Facilities

In most cases, estimates of projected affected facility counts are generated by assuming fixed proportional relationships with the site counts. This means that as site counts are projected to expand (construction of new sources) or contract (retirement of existing sources), the counts of affected facilities expand and contract as well such that the ratio of facilities to sites remains constant. Details for each affected facility type are provided below.

(a) Fugitives and Leaks

The final rule features LDAR requirements across all segments. Well site requirements are the most nuanced and depend on the equipment present at the site, which we characterize through a series of data processing steps. Compressor station requirements are uniform across segments, and we rely on a single representative plant in each segment to estimate the impacts of those requirements. Requirements at natural gas processing plants distinguish the collection of

[41] The dataset of processing plants is downloaded from https://hifld-geoplatform.opendata.arcgis.com/datasets/geoplatform::natural-gas-processing-plants/explore. We filter out plants located in Canada and Mexico.

VOC service components and the collection of non-VOC service components. Our impacts analysis for processing plants differentiates between two model plant types representing "large" and "small" facilities.

The final rule features different monitoring frequency requirements for well sites depending on the equipment present at a site. The Enverus data does not provide information on site equipment, so we assign well site groups to equipment categories in fixed proportions based on analysis of data from the EPA's 2016 ICR and site-level survey data provided by the American Petroleum Institute (API).[42,43] The ICR data captured a survey of certain major equipment (separators, compressors, and dehydrators) and storage tanks at more than 100,000 well sites across the U.S., which we use to separately estimate the proportions of sites in eleven equipment categories and two tank bins for all combinations of oil and natural gas sites, production bins, and single and multi-well sites at the regional level, where the data was sufficient.[44] For a few regions, all site observations within each region were pooled to estimate equipment and storage vessel bin proportions.

Since the ICR data does not contain information on heater-treaters and process heaters, we supplement with information on those equipment types from the API survey data. Grouping the API survey sites by the presence of separators, compressors, and/or dehydrators (i.e., has major equipment surveyed in the ICR or not); regions; site types (oil or natural gas); and well count bins (single or multi), we calculated the proportion of sites with heater-treaters, and process heaters for each combination. The proportions were then applied to the equipment bins

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[42] See https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/background-information-request-oil-and for more information on the ICR. The ICR was withdrawn in 2017, but not before significant amounts of data were collected. The data used for this analysis were obtained from the file "OilandGasSpreadsheetUnredacted.xlsx" found at https://foiaonline.gov/foiaonline/action/public/submissionDetails?trackingNumber=EPA-HQ-2017-003014&type=Request.

[43] See Attachment 4 (Microsoft Excel workbook) of Docket ID No. EPA-HQ-OAR-2017-0757-0002, EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API. The dataset contains survey data on 2,183 gas well sites and 1,742 oil well sites.

[44] The equipment categories are: (1) no separators, compressors, or dehydrators; (2) one separator; (3) more than one separator; (4) one compressor; (5) more than one compressor; (6) one dehydrator; (7) more than one dehydrator; (8) both separator(s) and compressor(s); (9) both separator(s) and dehydrator(s); (10) both compressor(s) and dehydrator(s); and (11) separator(s), compressor(s), and dehydrator(s). The storage vessel categories are: (1) has tanks, and (2) does not have tanks. Since we estimate proportions for all combinations of equipment bin, storage vessel bin, region (AK, GC, MC, NE, NP, RM, SW, and WC), site type (oil, gas), production level (low, non-low) and well count bin (single, multi), there are 1,408 possibilities in total.

developed from the ICR data to estimate site proportions for all equipment bin combinations including heater-treaters and process heaters.[45]

We also estimate average equipment and storage vessel counts for each equipment and storage vessel bin combination. For single well sites, there are distinct estimates of separators, compressors, and dehydrators for each combination of region, equipment bin, and storage vessel bin at a minimum, with further disaggregation by site type and production level where possible. For multi-well sites, we fit linear models to estimate average equipment counts as a function of site well counts, constraining the estimated parameters to agree with the equipment bins for all possible well counts (e.g., at least one separator in each equipment bin that denotes the presence of a separator, at least two separators in the equipment bin that designates more than one separator at the site).[46] Average equipment counts for heater-treaters and process heaters are calculated from the API data for each combination of region, site type, well count bin, and equipment presence. See Section 2.7 for a detailed discussion of how the ICR data is processed to construct equipment bin proportions and average equipment counts.

After assigning equipment proportions and average counts from the ICR and API survey data to the well site group projections, the base year results were compared to 2019 activity data from the 2021 GHGI. For the major equipment survey in the ICR (separators, compressors, and dehydrators), the aggregate equipment counts were reasonably close and so no further adjustments were made. For the additional major equipment types only found in the API survey (heater-treaters and process heaters), the aggregate equipment counts estimated by applying the API equipment proportions and averages to the well site group projections were significantly larger than the estimates from the GHGI. The discrepancy is probably due to the underlying population of the API survey, which was intended to reflect the types of sites that would be

[45] The result is a total of 37 possible equipment bins: one “no equipment” bin, five “exactly one piece of major equipment” bins (one for each major equipment type), five “exactly one major equipment type but more than one piece of equipment” bins (one for each major equipment type), ten “exactly two major equipment types” bins (all combinations), ten “exactly three major equipment types” bins (all combinations), five “exactly four major equipment types” bins (all combinations), and one bin for having all five types of major equipment.

[46] Due to a lack of observations of multi-well sites, the linear models were fit to higher aggregations of regions, site types, and equipment, storage vessel, and production level bins. For separators, compressors, and dehydrators, distinct models were run for two equipment bin categories: (1) separators-only with more than one piece of major equipment, and (2) more than one type of major equipment. For separators, the data was sufficient to estimate models for each region, while for compressors and dehydrators, the models were estimated at the national level. For storage vessels, separate regional models were estimated on all sites with at least one storage vessel.

impacted by NSPS OOOOa requirements. Such sites would be expected to be larger and have more equipment than the overall population of production sites. Therefore, the equipment proportions and average counts for heater-treaters and process heaters were calibrated by reducing the prevalence of those equipment types for older (pre-NSPS OOOO) sites until the aggregate estimates for the well site group projections in the base year matched the GHGI activity data.

Beyond the major equipment types discussed above, we characterize two other types of equipment that have fugitive components in the well site group projections, headers and meters/piping. Initially, a header is assigned to all oil sites with at least one piece of major equipment or storage vessel. As was the case for process heaters and heater-treaters, this resulted in far more headers per well in the well site group base year projection than estimated in the GHGI activity data. To bring the projections more in line with the GHGI, we calibrated the proportion of pre-NSPS OOOO oil sites assumed to have headers such that the aggregate ratio of headers per well matched the values from the GHGI. For meters/piping, we assigned one unit to all gas well sites.

The equipment category proportions are illustrated in Table 2-5 for well sites in the base year and newly constructed sites in subsequent vintages. The table reflects the distribution of sites after making the adjustments for heaters and heater-treaters and applying the stratified proportions to the well site group dataset. We assume that equipment is assigned to well sites based on current year production levels, reflecting the reallocation of equipment away from certain sites as production declines.

Fugitive emissions monitoring requirements differ across the equipment bins captured in the table. In the analysis of the finalized option, single well wellhead-only sites and sites with only one major piece of equipment and no tank battery are assumed to perform quarterly AVO inspections. Wellhead-only sites with multiple wells are assumed to perform quarterly AVO and semiannual OGI monitoring. Sites with two or more major pieces of equipment, one piece of major equipment and a tank battery, or multi-wellhead sites with one piece of major equipment or a tank battery are assumed to perform bimonthly AVO and quarterly OGI monitoring. To calculate impacts for the fugitive monitoring requirements at well sites, we allocate the total number of well sites to the bins defined by counts of major equipment and tank batteries.

Table 2-5 Distribution of Well Sites in Equipment Bins

Site Bin	TSD Model Plant	Proportions in the base year (2019)	Proportions in the projected years (2020–2023)	Proportions in the projected years (2024–2038)
Natural Gas				
Single wellhead				
Wellhead only	1	33%	21%	21%
Small sites	1	18%	6%	6%
Large sites without controlled storage vessels	3	44%	23%	23%
Large sites with controlled storage vessels	4	<1%	5%	5%
Multi-wellhead				
Wellhead only	2	<1%	<1%	<1%
Large sites without controlled storage vessels	3	5%	36%	15%
Large sites with controlled storage vessels	4	<1%	9%	29%
Oil				
Single wellhead				
Wellhead only	1	49%	26%	26%
Small sites	1	11%	7%	7%
Large sites without controlled storage vessels	3	27%	7%	5%
Large sites with controlled storage vessels	4	3%	17%	19%
Multi-wellhead				
Wellhead only	2	2%	4%	4%
Large sites without controlled storage vessels	3	3%	4%	3%
Large sites with controlled storage vessels	4	4%	34%	34%

Affected facility counts for compressor station fugitives are equal to the compressor station counts detailed in the previous section. As such, compressor station fugitives affected facility counts are binned according to segment, vintage, and year.

There are two affected facility types associated with natural gas processing plant leaks: the collection of VOC service components and the collection of non-VOC service components. In each case, the number of affected facilities is equal to the number of processing plants, and so the total number of affected facilities is twice the number of processing plants. For the purposes of calculating impacts associated with LDAR at processing plants, we assume that 80 percent of plants are “large”, and 20 percent are “small”.[47]

[47] See page 6 of Chapter 10 of the November 2021 TSD.

(b) Pneumatic Controllers

Pneumatic controllers are represented in the GHGI for all segments. For well sites, we estimate the number of controllers at sites based on equipment counts. For compressor stations, controller counts are directly based on per-station counts from the GHGI in 2019. For processing plants, we assume that all controllers are already powered by compressed air and therefore do not estimate any impacts under the final rule for that segment and affected facility.

To estimate controller counts at well sites, we proceed in two steps. First, we multiply, for each well site group, equipment counts per site by controller-per-equipment factors presented in the Supporting Information of Zavala-Araiza et al. (2017).[48] Equipment counts for separators, compressors, dehydrators, and process heaters per site are calculated as described in the preceding section on fugitives and leaks. Plunger lifts are assigned to low production gas sites such that the aggregate proportion of gas sites with plunger lifts in the well site group projections matches the 2019 proportion from the 2021 GHGI activity data. The resulting aggregate implied controller counts for the base year are close to those from the GHGI activity data, so no further calibration steps are taken. Second, we allocate the controllers across to three types (low-bleed, high-bleed, and intermittent bleed) such that each type matches the corresponding GHGI controller per-well counts in 2019, assuming that no high-bleed controllers exist at post-OOOO sites in any state and at pre-OOOO sites in California, Colorado, or Utah.

The estimation of controller counts at compressor stations is similar to the last step for well sites. In that case, we assume that high-bleed controllers are only allocated to pre-OOOO gathering and boosting stations and pre-OOOOa stations for transmission and storage. In aggregate, the per-station counts for all three types of controllers in the base year match the per-station counts from the GHGI in 2019.

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[48] Using data from Allen et al. (2015), the authors estimate 0.42 controllers per wellhead, 0.90 controllers per plunger lift, 1 controller per separator at gas sites without liquids production, 2.06 controllers per separator at sites with liquids production, 1.5 controllers per process heater, 4.3 controllers per compressor, and 2.5 controllers per dehydrator. To prevent certain sites from having a fractional controller count, we assume 1 controller per plunger lift. We also assume, in lieu of a specific estimate, that each heater-treater has 1.5 controllers (same as process heaters and roughly the midpoint between separators at sites with and without liquids production). Finally, based on a review of the underlying data from Allen et al. (2015), we assume that all controllers at wellheads qualify as emergency shutdown devices and are thus not subject to the controller requirements.

(c) Pneumatic Pumps

The GHGI provides information on the number of pneumatic pumps in the production and gathering and boosting segments. For well sites, we assume that 30 percent of gas sites with equipment (and no sites without equipment) have chemical injection pneumatic pumps, based on analysis of the data underlying Allen et al. (2013).[49] Likewise, we assume 25 percent of oil sites with equipment have chemical injection pneumatic pumps, based on an analysis of the API survey data. For each site assumed to have pumps, we initially assign one pump to the site. Additional pumps are assigned in proportion to the number of pneumatic controllers at each site such that number of pumps per-well matches the 2019 data from the GHGI. For the gathering and boosting segment, we calculate the number of pumps per station implied by the GHGI in 2019 and apply the value to all stations for all vintages in all years.

(d) Reciprocating Compressors

The GHGI contains estimates of the number of reciprocating compressors in the gathering and boosting, processing, transmission, and storage segments. In all cases, we calculate the number of reciprocating compressors per site using the 2019 values from the GHGI and apply those ratios to the cumulative and new station counts for all vintages and years. In the case of gathering and boosting stations, the GHGI only includes a total count of compressors; we assume that 89 percent of those are reciprocating.[50]

(e) Centrifugal Compressors

The GHGI contains estimates of the number of wet seal centrifugal compressors in the gathering and boosting, processing, and transmission segments. For the transmission segment, we assume that no wet seal compressors have been installed since the NSPS OOOOa due to the routing requirements in that rule, and that no wet seal compressors will be installed at NSPS OOOOb-affected stations either. Taking that into account, wet seal compressors are allocated on a per-station basis such that the estimated aggregate counts of wet seal compressors per station in

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[49] The data can be downloaded from http://dept.ceer.utexas.edu/methane/study/datasets3.cfm. The workbook used for this analysis is final_SITES.xlsx.

[50] This assumption is based on data summarized on page 28 of Zimmerle et al. (2019).

the base year match the GHGI data from 2019. For gathering and boosting stations, the process is similar except we allocate wet seal compressors to all vintages since this segment/affected facility type has yet to be regulated. Also, the GHGI only includes a total count of compressors for this segment; we assume that 3 percent of those are centrifugal,[51] and that the proportion of wet seal to dry seal centrifugal compressors is the same as it is in the transmission segment.

(f) Liquids Unloading

For the purposes of the RIA, liquids unloading affected facilities are defined at the event level and apply only to natural gas well sites. To estimate impacts, we divide natural gas well site groups into two categories: those with plunger lifts and those without plunger lifts. The process for allocating plunger lifts across sites is described in the pneumatic controller section above; the process for allocating sites that have liquids unloading without plunger lifts is similar, as the GHGI contains activity data for the number of wells that perform liquids unloading events, so we divide that number by the total number of natural gas wells in the inventory in 2019 to generate fractions of wells performing liquids unloading for each category. Those fractions are applied to our projections of well sites with equipment for all years and vintages. In the case of wells with plunger lifts, we assume that 76 percent of sites perform manual unloading.[52] Finally, we convert from sites to events by multiplying by events per well values from the BSER analysis.[53]

(g) Associated Gas

Associated gas affected facility projections at well sites are constructed by applying base year proportions of associated gas to the well site group projections. First, proportions of oil wells with associated gas flaring and venting are calculated at the regional level using GHGRP data for the 2019 reporting year. Next, the well site group data for the base year is used to calculate proportions of oil wells both with and without gas production on site, conditional on the

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[51] Ibid.

[52] Memorandum. *Analysis of Greenhouse Gas Reporting Program Liquids Unloading Data*. Prepared by SC&A Incorporated for Amy Hambrick, SPPD/OAQPS/EPA. October 14, 2021. Docket ID No. EPA-HQ-OAR-2021-0317-0143. As summarized in the memo, analysis of well-level data from the GHGRP for reporting years 2015–2019 suggested that 76% of plunger lifts were manually operated.

[53] See page 12 of Chapter 11 of the November 2021 TSD. We assume that wells without plunger lifts have 5.6 events per year, and wells with manually operated plunger lifts have 7.7 events per year.

presence of a separator on site; gas sites and oil sites without separators are assumed not to have associated gas venting or flaring. Oil sites with separators are then partitioned into three categories: (1) no associated gas; (2) associated gas flaring; and (3) associated gas venting, such that the aggregate proportion of oil wells in each region with associated gas flaring and venting matches the GHGRP data, and no sites with gas production are assigned as having associated gas flaring or venting before any oil site with a separator without gas production. Notably, the proportions of oil sites with associated gas venting and flaring are assumed to be constant across vintages and production levels after conditioning on the region and presence of separators, due to a lack of data that would allow for more nuanced assumptions.

(h) Storage Vessels

Storage vessel-affected facility projections are generated for well sites only; projections of tanks at centralized production facilities and in the gathering and boosting segment have been omitted due to a lack of data. As described in Section 2.2.1.2(a)(a), proportions of sites with tanks and tank counts per oil and natural gas well are generated from the 2016 ICR data and merged into our well site projections. For each site assumed to have tanks, the total count of tanks is assumed to comprise a single tank battery. All liquids production at those sites (crude at oil sites, condensate at gas sites) is assumed to be throughput to the tank battery.

2.2.1.3 Incrementally Impacted Facilities

Estimates of incrementally impacted facility counts by year and regulated facility for the final rule are presented in Table 2-6 through Table 2-8. The counts for well sites and compressor stations represent fugitives requirements at those sites and the counts for natural gas processing plants represent VOC and non-VOC service.

Table 2-6 Projection of Incrementally Impacted Affected Facilities under the Final NSPS OOOOb and EG OOOOc, 2024 to 2038 (Production Sources)

	Fugitive Emissions		Pneumatics			Associated Gas	Liquids Unloading	Storage Vessels	
Year	**Well Sites**	**Flares**	**Well Sites**	**Controllers**	**Pumps**	**Well Sites**	**Events**	**Tank Batteries**	**Tanks**
2024	8,800	4,700	6,500	45,000	1,900	2,300	460	570	1,900
2025	18,000	9,800	14,000	95,000	4,000	4,700	980	1,200	4,000
2026	28,000	15,000	21,000	140,000	6,200	7,200	1,500	1,900	6,300
2027	38,000	20,000	28,000	190,000	8,300	9,700	2,100	2,500	8,300
2028	520,000	55,000	350,000	1,400,000	100,000	67,000	270,000	3,000	9,700
2029	510,000	57,000	350,000	1,400,000	100,000	67,000	260,000	3,400	11,000
2030	500,000	59,000	340,000	1,400,000	100,000	67,000	260,000	3,800	12,000
2031	490,000	63,000	340,000	1,400,000	99,000	68,000	250,000	4,200	13,000
2032	480,000	66,000	340,000	1,400,000	98,000	68,000	250,000	4,600	15,000
2033	480,000	69,000	330,000	1,400,000	97,000	68,000	240,000	5,000	16,000
2034	470,000	70,000	330,000	1,400,000	96,000	69,000	240,000	5,600	19,000
2035	460,000	73,000	330,000	1,400,000	95,000	69,000	230,000	6,500	23,000
2036	460,000	76,000	320,000	1,400,000	94,000	70,000	230,000	7,300	26,000
2037	450,000	79,000	320,000	1,400,000	93,000	70,000	220,000	8,700	35,000
2038	440,000	82,000	320,000	1,400,000	92,000	71,000	220,000	9,800	38,000

Table 2-7 Projection of Incrementally Impacted Affected Facilities under the Final NSPS OOOOb and EG OOOOc, 2024 to 2038 (Non-Production Fugitive/Leaks and Pneumatics Sources)

	Fugitives/Leaks			Pneumatics				
	Gathering and Boosting	Processing	Transmission and Storage	Gathering and Boosting			Transmission and Storage	
Year	**Stations**	**Plants**	**Stations**	**Stations**	**Controllers**	**Pumps**	**Stations**	**Controllers**
2024	0	6	0	420	4,100	440	99	1,700
2025	0	11	0	850	8,200	880	200	3,400
2026	0	17	0	1,300	12,000	1,300	300	5,100
2027	0	23	0	1,700	16,000	1,800	400	6,800
2028	5,200	590	1,900	11,000	100,000	11,000	3,200	59,000
2029	5,100	590	1,900	11,000	110,000	11,000	3,300	61,000
2030	5,100	590	1,800	11,000	110,000	12,000	3,300	62,000
2031	5,000	590	1,800	12,000	110,000	12,000	3,400	63,000
2032	5,000	600	1,800	12,000	120,000	13,000	3,500	65,000
2033	5,000	600	1,800	13,000	120,000	13,000	3,600	66,000
2034	4,900	600	1,800	13,000	130,000	13,000	3,700	68,000
2035	4,900	600	1,800	13,000	130,000	14,000	3,800	69,000
2036	4,900	600	1,800	14,000	130,000	14,000	3,900	71,000
2037	4,800	600	1,800	14,000	140,000	15,000	3,900	72,000
2038	4,800	600	1,700	15,000	140,000	15,000	4,000	73,000

Table 2-8 Projection of Incrementally Impacted Affected Facilities under the Final NSPS OOOOb and EG OOOOc, 2024 to 2038 (Non-Production Compressor Sources)

	Reciprocating Compressors			Wet-Seal Centrifugal Compressors		
Year	**Gathering and Boosting Stations**	**Processing Plants**	**Transmission and Storage Stations**	**Gathering and Boosting Stations**	**Processing Plants**	**Transmission and Storage Stations**
2024	970	38	290	13	0	0
2025	1,900	76	570	26	0	0
2026	2,900	110	860	39	0	0
2027	3,900	150	1,100	52	0	0
2028	24,000	4,000	9,500	320	280	740
2029	25,000	4,000	9,700	340	280	740
2030	26,000	4,000	10,000	350	280	730
2031	27,000	4,000	10,000	360	280	730
2032	28,000	4,000	10,000	370	270	720
2033	29,000	4,000	11,000	380	270	720
2034	30,000	4,000	11,000	390	270	710
2035	31,000	4,000	11,000	410	260	710
2036	31,000	4,000	11,000	420	260	700
2037	32,000	4,100	12,000	430	260	700
2038	33,000	4,100	12,000	440	260	690

2.2.2 Model Plant Compliance Cost and Emissions Reductions

The cost and emissions characteristics of the site projections used to estimate the impacts of the final rule are derived from the technical analyses underpinning the BSER determination. In some cases, we characterize our affected facilities to be identical to the model plants found in the Final Rule TSD, December 2022 TSD, or the November 2021 TSD, and so the cost and emissions estimates can be directly applied. In other cases, however, our model plants leverage the underlying data from the TSDs and other data sources to better fit the activity data and account for source heterogeneity.

(a) Compressor Station Fugitives, Natural Gas Processing Plant Leaks, and Compressors

We use cost and emissions information directly from the November 2021 TSD for compressor station fugitives, natural gas processing plant leaks, and reciprocating compressors, and from the December 2022 TSD for centrifugal compressors. Compressor station fugitives are represented by a single model plant for each of the gathering and boosting, transmission, and storage segments.[54] Processing plant leaks are divided into four different model plants: all combinations of large and small plants, and VOC and non-VOC service.[55] Reciprocating compressors are represented by a single model plant for each of the gathering and boosting, processing, transmission, and storage segments.[56] Wet-seal and dry-seal centrifugal compressors are each represented by a single model plant for each of the gathering and boosting, processing, and transmission segments.[57]

(b) Storage Vessels

Storage vessel control costs and emissions reductions are adapted from the BSER analysis summarized in Chapter 6 of the November 2021 TSD. For each well site group assumed to have tanks, representative site-level tank potential to emit (PTE) is calculated by multiplying crude or condensate throughput by an average emissions factor derived from the BSER analysis.[58] To determine which post-OOOO sites are assumed to have controlled tanks in the baseline, we use the VOC PTE estimate in the base year or initial year of construction, whichever is later; pre-OOOO sites are assumed to be uncontrolled in the baseline. In the final rule scenario, control requirements are determined by the VOC PTE estimates in the year of construction for NSPS OOOOb-affected facilities and CH_4 PTE estimates in the year that the EG

[54] See Chapter 12 of the November 2021 TSD for details on costs and emissions reductions associated with quarterly OGI monitoring, which represents the proposed BSER for compressor station fugitives in both the NSPS OOOOb and EG OOOOc.

[55] See Chapter 10 of the November 2021 TSD for details on costs and emissions reductions associated with NSPS VV Method 21 (the BSER established in NSPS KKK), NSPS VVa Method 21 (the BSER established in NSPS OOOO), and bimonthly OGI (the BSER proposed in NSPS OOOOb and EG OOOOc).

[56] See Chapter 7 of the November 2021 TSD for details on costs and emissions reductions associated with rod-packing replacement on a fixed schedule (the BSER established in NSPS OOOO and NSPS OOOOa) and rod-packing replacement based on emissions monitoring (the BSER proposed in NSPS OOOOb and EG OOOOc).

[57] See Chapter 2 of the December 2022 TSD for details on costs and emissions reductions associated with a direct inspection and maintenance/repair program to maintain emissions below 3 scfm (the BSER proposed in NSPS OOOOb for dry seals and EG OOOOc for wet and dry seals).

[58] Emission factors are estimated by calculating the average VOC and methane emissions per barrel across the sample tanks on the “Condensate” and “Oil” tabs from the docketed workbook, EPA-HQ-OAR-2021-0317-0039_attachment_21. Condensate emissions factors were applied to sites in AAPG Geological Provinces with average API gravity greater than or equal to 40, while oil emissions factors were applied to sites in AAPG Geological Provinces with average API gravity less than 40. Average API gravity for all AAPG Geological Provinces was calculated by taking the average API gravity from Table J.1 in Subpart W reporting year 2019 for all facilities, weighted by reported oil volume; see https://enviro.epa.gov/query-builder/ghg/PETROLEUM%20AND%20NATURAL%20GAS%20SYSTEMS%20(RY%202015-2022)/EF_W_ATM_STG_TANKS_CALC1OR2.

is assumed to take effect (2028) for EG OOOOc-affected facilities.[59] For sites subject to control requirements, we assume that 95 percent control is achieved through application of flares to the entire tank battery. The costs of control are based on the BSER analysis, with capital and annual costs equal to a minimum value below a 50 TPY CH_4 emissions threshold and following a quadratic cost function for sites with emissions above that threshold.[60]

(c) Well Site Fugitives

The methodology for projecting of costs and emissions impacts from AVO and OGI monitoring programs of different frequencies in the production segment uses counts of major equipment in well site groups (described in Section 2.7), the results of the BSER technical analysis performed in support of this action, and information on process emissions from the scientific literature. The BSER analysis is used to estimate baseline fugitive emissions from major equipment components and thief hatches at controlled storage vessels, as well as monitoring program costs and performance. Data from the scientific literature is used to estimate baseline emissions due to inactive flares at controlled storage vessels; OGI monitoring of flares is a requirement in the final rule.

The BSER analysis uses simulations produced by the Fugitive Emissions Abatement Simulation Tool (FEAST).[61] FEAST calculates simulated costs and emissions reductions of LDAR programs at model well sites under different assumptions. The BSER analysis performs FEAST simulations using four model well sites (a single-well site with no major equipment (MP1); a multi-well site with no major equipment (MP2); a multi-well site with a separator, an in-line heater, and a dehydrator (MP3); and a multi-well site with a separator, an in-line heater, a dehydrator, and a controlled storage tank battery (MP4)) and five OGI frequencies (annual, semiannual, quarterly, bimonthly, and monthly). Each model well site has an assumed number of components based on the number of wells and the type of major equipment present at the site. A

[59] Note that V2 and V3 vintage sites are subject to the more stringent of NSPS OOOO and NSPS OOOOc, which we assume is NSPS OOOO.

[60] The cost functions above the threshold are estimated by fitting a quadratic function of methane emissions on cost using data points for methane emissions of 50, 150, 300, and 1500 TPY in the "New" and "Existing" tabs from the docketed workbook, EPA-HQ-OAR-2021-0317-0039_attachment_20. The fitted cost functions imposed a constraint that the functions be equal to the cost values from the workbook at an emissions rate of 50 TPY CH_4.

[61] See Chapter 5 of the December 2022 TSD for details on the FEAST modeling and costs and emissions reductions associated with OGI monitoring at well sites.

FEAST simulation for a model well site produces an average annualized cost and emissions reduction percentage for each OGI monitoring frequency along with a baseline emissions rate in the absence of an LDAR program. Given that the only difference between MP3 and MP4 sites is the presence of storage tank battery control at the latter, we assume that the difference in baseline emissions between the two sites is due to thief hatch emissions and that those emissions are reduced by the same proportion as component emissions for a given LDAR program.

Emissions factors for process emissions due to inactive flares at controlled storage vessels in the production segment are estimated through a series of steps, starting with data published as supporting information to Cusworth et al. (2021). First, we merge the plume and source data from the study so that we can identify emissions sources in the data specific to inactive flares at storage vessels. To ensure that we are capturing emissions that could reasonably be reduced by an LDAR program, we limit the sample to sources that were identified by at least three overhead flights and calculate average emissions for each source using persistence-weighting. Then, we calculate average emissions across sources to arrive at an emissions factor (in tons per year of methane) for an inactive flare at a production segment tank battery. Finally, we convert the emissions factor for inactive flares to an emissions factor for all flares by multiplying by an estimate of the ratio of inactive flares to total flares at storage vessels within the study area. Since an estimate of the total number of flares at storage vessels in the study area was not available, we estimated one by using our well site group data to estimate the number of storage vessel flares per well in the southwest region (since the Cusworth et al. (2021) study was conducted on the Permian basin) and applied it to the number of wells in the study area (~72,000, according to the study authors).

The calculation of LDAR (including OGI monitoring at controlled storage vessels) costs and emissions impacts from a well site group consists of five main steps. First, a well site group is assigned major equipment as described in Section 2.2.1.2(a). Second, each well site group is matched to a FEAST model well site based on major equipment counts. Single-well sites with no major equipment or one piece of major equipment are matched to MP1, while multi-well sites with no major equipment are matched to MP2. All other sites are matched, depending on whether they are assumed to have controlled storage tank batteries, to either MP3 (without) or MP4 (with). The presence of control of storage vessels for each well site group is estimated based on a combination of estimated emissions, prior requirements under NSPS OOOO and

NSPS OOOOa, and new requirements under NSPS OOOOb and EG OOOOc. Third, a component count per well site is determined for a well site group based on the counts of major equipment from step 1. Component counts for each type of major equipment are assigned based on Tables W-1B (for gas well sites) and W-1C (for oil well sites) from 40 CFR part 98, Subpart W.[62] Fourth, the number of components per well site are multiplied by a per-component emissions factor and summed over well sites to determine baseline component emissions for a well site group, while thief hatch and inactive storage vessel flare emissions factors are applied to sites with controlled storage vessels. The per-component emissions factor is calculated by fitting a linear model regressing baseline emissions on component counts for MP1, MP2, and MP3 from the FEAST simulations. Finally, the cost and emissions impacts of an OGI monitoring program of a given frequency is determined by applying the average annualized cost and emissions reduction percentage for the matched model well site from the FEAST simulations to the well site group.

(d) Pneumatic Devices

Control of pneumatic controllers and pneumatic pumps are analyzed in a unified framework for pneumatic devices using a combination of BSER analysis, Carbon Limits' abatement cost tool, and the GHGI. Our analysis incorporates the impacts of replacing high bleed with low bleed pneumatic controllers,[63] which reflects the BSER established in NSPS OOOO for well sites and gathering and boosting stations and NSPS OOOOa for transmission and storage compressor stations, as well as three zero emitting control options: electronic controllers using grid electricity, electronic controllers powered by solar photovoltaic (PV) and battery systems, and compressed air systems using grid electricity.[64] Emissions factors for low-bleed, high-bleed, and intermittent bleed pneumatic controllers (all segments except processing) and pneumatic pumps (production and gathering and boosting) from the BSER analysis are converted from kg CH_4 per device to tons CH_4 per device and applied directly to device counts at the site level to

[62] See https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98.

[63] See Chapter 8 of the November 2021 TSD for details on costs and emissions reductions associated with replacing high bleed with low bleed pneumatic controllers.

[64] See Chapter 3 of the December 2022 TSD and Attachment Q "Carbon Limits 2021 Zero Bleed Pneumatics Cost Tool" at https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0845 for details on costs and emissions reductions associated with installing zero-bleed controllers (the BSER established in NSPS OOOO for processing plants and proposed in NSPS OOOOb and EG OOOOc for all other segments).

calculate site-wide emissions, pre- and post-control.[65] Control costs vary across control options and are described in detail below.

For each control option, pneumatic device control costs are comprised of capital and annual operations and maintenance costs, each of which is based on two main components: site-level "base" costs that are independent of the number of devices at the site, and costs that scale with the number of devices at the site. For replacement of high-bleed controllers with low-bleed controllers, control costs scale linearly with the number of high-bleed controllers at the site and are estimated using the BSER analysis from the 2011 TSD after updating to 2019 dollars (U.S. EPA, 2011c). Consistent with the Carbon Limits tool assumptions, we assume retrofit capital costs for low-bleed controllers (not including installation labor costs) are half of the cost of new capital costs, since only the controller and not the control valve will be required. For electronic controllers powered by solar photovoltaic and battery systems, we calculate the base and per-device capital costs associated with installing and replacing control panels, solar PV panels, batteries, and devices and annual (per-device) costs associated with device maintenance. Cost calculation for electronic controllers powered by grid electricity is similar, but with solar PV and battery capital costs replaced by base and per-device annual electricity costs. For compressed air systems, we calculate the base and per-device capital costs associated with installing and replacing a compressor and base and per-device annual costs associated with compressor maintenance and grid electricity purchases.[66]

For the final rule, as well as the regulatory alternatives specified in Section , control options are applied at the site level and compared to the baseline. Costs in the baseline consist of purchasing and installation costs (for newly constructed sites) and maintenance costs (for newly constructed and existing sites) of natural gas-driven pneumatic devices. We assume that electronic controllers powered by solar PV and battery systems are used to comply with the zero emissions standard at all well sites. In contrast, we assume that gathering and boosting and

[65] The emissions factor used for pumps is a blend of the diaphragm and piston pump emission factors used in the BSER analysis, assuming 50.2% of pumps are diaphragm pumps, which is consistent with the calculation method used in the GHGRP.

[66] Based on the Carbon Limits tool, we assume that compressor costs (capital and maintenance) are a quadratic function of horsepower requirements, which is a linear function of the number of each type of device at the site. Therefore, we model a second-order polynomial relationship between site-level compressor costs and the numbers of each type of device at the site.

transmission and storage compressor stations are grid-connected and comply with the regulation through, due to the large number of controllers assumed to be located at the model plants, installation of a compressed air system.

(e) Liquids Unloading

We define two model plants for liquids unloading: events at wells without plunger lifts and manual unloading events at wells with plunger lifts. In both cases, the costs per event are taken directly out of the December 2022 TSD. However, whereas the BSER analysis evaluates a range of emissions reductions levels associated with the final option, this analysis assumes emissions reductions of 29 percent and 36 percent for events at wells without plunger lifts and manual unloading events at wells with plunger lifts, respectively.[67]

(f) Associated Gas

Cost and emissions impacts for associated gas are estimated through a combination of assumptions from the BSER analysis (see the 2023 Final Rule TSD) and the GHGI. Baseline emissions are calculated by applying the 2019 basin-level, per-million-barrel emissions factors from the 2021 GHGI to the estimated production levels of the well site groups estimated to have associated gas flaring or venting as described in Section 2.2.1.2(g). The cost and performance assumptions are derived from the BSER analysis. We assume that flares have 95 percent control efficiency with capital costs of $100,579 and annual costs of $25,000 in 2019 dollars. The costs of routing to a sales line are estimated based on assumptions of a line length of 4 miles, compressor horsepower of 25 hp, and gathering line capital costs halfway between the costs of 4-inch line and 6-inch line. Sites with associated gas flaring in the baseline only incur costs (and achieve emissions reductions) if they are assumed to route to sales lines in the policy scenarios. For our analysis of the final rule, we assume that all NSPS OOOOb-affected facilities route to sales lines, while EG OOOOc-affected facilities only route to sales lines if estimated pre-flare associated gas emissions (assuming 95 percent control for sites with associated gas flaring) are greater than 10 tons of methane per year; otherwise, they are assumed to route to flare.

[67] See Chapter 11 of the November 2021 TSD for details on costs associated with best management practices during liquids unloading events, which is the compliance option we assume for this analysis. Additionally, see the memo titled "Analysis of Greenhouse Gas Reporting Program Liquids Unloading Data," Docket ID No. EPA-HQ-OAR-2021-0317-0143.

2.2.3 State Programs

The oil and natural gas industry is subject to numerous state and local requirements. These requirements differ greatly in scope and stringency across states. Given the difficulty in attempting to incorporate the myriad of state regulations in the baseline, we have chosen to incorporate state actions into the baseline for California and Colorado. Both states have comprehensive regulatory programs for the oil and natural gas industry and contribute significantly to national production levels. We have also incorporated fugitive monitoring requirements in New Mexico and Pennsylvania into the baseline. By not accounting for state and local requirements (outside of Colorado, California, New Mexico, and Pennsylvania) in the baseline, this analysis may overestimate both the benefits and the costs of the final regulation.

Specifically, we assume that California and Colorado have requirements at least as stringent as those in the final rule for compressor station fugitives, natural gas processing plant leaks, pneumatic devices, reciprocating compressors, wet seal centrifugal compressors, storage vessels; and associated gas. In addition, we assume that Colorado has requirements at least as stringent as those in the final rule for liquids unloading. For well site fugitives, we assume California, Colorado, Pennsylvania, and New Mexico have requirements at least as stringent as those in the final rule.

To incorporate the California, Colorado, New Mexico, and Pennsylvania rules in the baseline, our activity data projections for sites and affected facilities need to estimate the counts for those states. For the production segment, the processes described in Section 2.2.1.1 already account for state level activity counts. For the other segments, midstream data from HIFLD and Enverus was used to calculate the proportions of natural gas processing plants and compressor stations, respectively, in California and Colorado. We assume that those proportions hold fixed in all analysis years, and that affected facilities are also distributed according to those proportions.

2.3 Emissions Reductions

Table 2-9 summarizes the emissions reductions associated with the final standards. The emissions reductions are estimated by multiplying the source-level emissions reductions associated with each applicable control and facility type by the number of affected sources of that facility type. We present methane emissions in both short tons and CO_2 Eq. using GWP of 28.

Table 2-9 Projected Emissions Reductions under the Final NSPS OOOOb and EG OOOOc, 2024–2038

	Emissions Changes			
Year	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO_2 Eq. using GWP=28)**
2024	250,000	77,000	2,900	6,400,000
2025	490,000	150,000	5,600	12,000,000
2026	700,000	210,000	8,000	18,000,000
2027	900,000	270,000	10,000	23,000,000
2028	4,900,000	1,300,000	48,000	120,000,000
2029	4,900,000	1,300,000	49,000	130,000,000
2030	5,000,000	1,300,000	49,000	130,000,000
2031	5,000,000	1,300,000	50,000	130,000,000
2032	5,100,000	1,300,000	50,000	130,000,000
2033	5,100,000	1,400,000	51,000	130,000,000
2034	5,100,000	1,400,000	51,000	130,000,000
2035	5,100,000	1,400,000	52,000	130,000,000
2036	5,200,000	1,400,000	53,000	130,000,000
2037	5,200,000	1,400,000	54,000	130,000,000
2038	5,200,000	1,500,000	55,000	130,000,000
Total	58,000,000	16,000,000	590,000	1,500,000,000

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

2.4 Product Recovery

The projected compliance costs presented below include the revenue from natural gas recovery projected under the final standards. Requirements for fugitive emissions monitoring, equipment leaks at processing plants, reciprocating and centrifugal compressors, pneumatic devices, and liquids unloading events are assumed to increase the capture of methane and VOC emissions that would otherwise be vented to the atmosphere, and we assume that a large proportion of the averted methane emissions can be directed into natural gas production streams and sold; see Chapters 2–4 (pneumatic devices and associated gas) of the Final Rule TSD, Chapters 2 (centrifugal compressors) and 5 (fugitive emissions) of the December 2022 TSD and Chapters 7 (reciprocating compressors) and 10–11 (equipment leaks at natural gas processing plants and liquids unloading) of the November 2021 TSD for details on the proportion of recovered emissions associated with the compliance options.

Table 2-10 summarizes the increase in natural gas recovery and the associated revenue. The AEO2022 projects Henry Hub natural gas prices generally rising from $3.17/MMBtu in 2024 to $3.68/MMBtu in 2038 in 2021 dollars, with a low of $2.98/MMBtu in 2026.[68] To be consistent with other financial estimates in the RIA, we adjust the projected prices in AEO2022 from 2021 dollars to 2019 dollars using the GDP-Implicit Price Deflator. We also adjust prices for the wellhead using an EIA study that indicated that the Henry Hub price is, on average, about 11 percent higher than the wellhead price (Budzik, 2002). Finally, we use a conversion factor of 1.038 MMBtu equals 1 Mcf.[69] Incorporating these adjustments, wellhead natural gas prices are assumed to rise from $2.78/Mcf in 2024 to $3.23/Mcf in 2038 in 2019 dollars, with a low of $2.61/Mcf in 2026.

Table 2-10 Projected Increase in Natural Gas Recovery under the Final NSPS OOOOb and EG OOOOc Option, 2024–2038

Year	Increase in Gas Recovery (Bcf)	Increased Revenue (millions 2019$)
2024	62	$170
2025	110	$290
2026	140	$380
2027	170	$460
2028	400	$1,100
2029	410	$1,200
2030	410	$1,300
2031	420	$1,300
2032	420	$1,300
2033	430	$1,400
2034	430	$1,400
2035	430	$1,400
2036	430	$1,400
2037	440	$1,400
2038	440	$1,400

Note: Values rounded to two significant figures.

Operators in the gathering and boosting, processing, and transmission and storage segments of the industry do not typically own the natural gas they transport; rather, they receive payment for the transportation and processing service they provide. From a social perspective,

[68] Available at: https://www.eia.gov/outlooks/aeo/excel/aeotab_13.xlsx. Accessed July 25, 2022.
[69] For MMbtu-Mcf conversion factor, see https://www.eia.gov/tools/faqs/faq.php?id=45&t=8#:~:text=One%20thousand%20cubic%20feet%20(Mcf,1.036%20MMBtu%2C%20or%2010.36%20therms. Accessed October 31, 2023.

however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in a national-level analysis. An economic argument can be made that, in the long run, no single entity bears the entire burden of compliance costs or fully appropriates the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is likely to be spread across different market participants. Therefore, the simplest and most transparent option for allocating these revenues would be to keep the compliance costs and revenues within a given source category and not make assumptions regarding the allocation of costs and revenues across agents.

2.5 Compliance Costs

Table 2-11 summarizes the compliance costs and revenue from product recovery for the evaluated emissions sources and points. Total costs consist of capital costs, annual operating and maintenance costs, and revenue from product recovery. Capital costs include the capital costs from the requirements on newly affected pneumatic devices, reciprocating compressors, storage vessels, and associated gas facilities, as well as the planning costs associated with monitoring requirements for fugitive emissions at well sites and compressor stations and equipment leaks at processing plants; these costs are reincurred as operators are assumed to have to renew survey monitoring plans or purchase new capital equipment at the end of its useful life. The annual operating and maintenance costs are due to requirements on fugitive emissions and equipment leaks, controllers at gas processing plants, compressors, liquids unloading events, storage vessels, and associated gas.

Note that Table 2-11 shows a pulse of capital expenditures in 2028, the year the RIA assumes to be the compliance year for the EG OOOOc. In practice, however, the EG OOOOc gives States and sources the flexibility to spread these installations over a period of up to three years, or the 2027 to 2029 period.[70] While we do not distribute compliance expenditures across these years in the RIA, we believe that States and sources will avail themselves of this flexibility.

[70] The compliance timeline for EG OOOOc is 36 months after the state plan submittal deadline. See Section XIII.E. of the final rule preamble for discussion on state plan submittal and compliance timelines.

Table 2-11 Projected Compliance Costs under the Final NSPS OOOOb and EG OOOOc Option, 2024–2038 (millions 2019$)

Year	Capital Costs	Operating and Maintenance Costs	Annualized Costs	Increased Revenue from Product Recovery	Annualized Costs with Increased Revenue from Product Recovery
2024	$1,400	$27	$180	$170	$3
2025	$1,500	$57	$370	$290	$78
2026	$1,600	$88	$560	$380	$190
2027	$1,600	$120	$760	$460	$300
2028	$13,000	$1,500	$3,600	$1,100	$2,500
2029	$1,600	$1,500	$3,800	$1,200	$2,500
2030	$1,600	$1,500	$3,900	$1,300	$2,600
2031	$1,600	$1,500	$4,000	$1,300	$2,700
2032	$1,900	$1,500	$4,000	$1,300	$2,700
2033	$1,600	$1,400	$4,100	$1,400	$2,800
2034	$1,700	$1,400	$4,100	$1,400	$2,800
2035	$1,600	$1,400	$4,300	$1,400	$2,900
2036	$2,100	$1,400	$4,400	$1,400	$3,000
2037	$1,700	$1,400	$4,500	$1,400	$3,100
2038	$1,800	$1,400	$4,600	$1,400	$3,200

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

The expected lifetimes that capital and planning costs are incurred over differs across affected facilities. The cost of designing, or redesigning, fugitive emissions monitoring programs at well sites and compressor stations are assumed to occur every eight years, while the planning cost associated with equipment leak surveys at processing plants are assumed to occur every five years. Pneumatic device lifetimes are assumed to be 15 years, the lifetimes of solar PV panels and batteries used to power electronic controllers are assumed to be 10 and four years, respectively, and the lifetime of compressors used to power compressed air systems is assumed to be six years. Rod-packing replacement at reciprocating compressors is assumed to happen about every three years in the processing segment and four years in the gathering and boosting and transmission and storage segments. The capital costs in each year outlined in Table 2-11 includes the estimated costs for newly affected sources in that year, plus the costs for sources affected previously that have reached the end of their assumed economic lifetime.

The calculation of total annualized costs proceeds as follows. Capital and planning costs are annualized over their requisite expected lifetimes at an interest rate of 7 percent. These annualized capital costs are then added to the annual operating and maintenance costs of the requirements to get the total annualized costs without product recovery in each year. The value of product recovery is then subtracted to get the total annualized costs with product recovery in each year. Under the final rule, over 90 percent of revenue from the sale of captured natural gas is projected to be earned by operators in the production segment of the industry, where we assume that the operators own the natural gas and will receive the financial benefit from the captured natural gas. The remainder of the captured natural gas is captured within the gathering and boosting, processing, transmission, and storage segments, where operators do not typically own the natural gas they transport; rather, they receive payment for the transportation service they provide. In the RIA, we treat these revenues as an offset to projected compliance costs, though the revenues could instead be considered as a benefit of the regulatory action. However, regardless of whether the revenue from capture of natural gas is considered a compliance cost offset or a benefit, the net benefits are equivalent.

Table 2-12 shows the undiscounted stream of costs for each year from 2024 through 2038 due to the final standards. Capital costs are the projected capital and planning costs expected to be incurred. Total costs are the sum of the capital costs and annual operating costs. The revenue from the increase in product recovery is estimated using the AEO2022 natural gas price projections, as described earlier. Total costs with revenue from product recovery equal the total anticipated costs minus the revenue.

Table 2-12 Undiscounted Projected Compliance Costs under the Final NSPS OOOOb and EG OOOOc, 2024–2038 (millions 2019$)

Year	Capital Costs	Annual Operating Costs	Total Costs (w/o Revenue)	Revenue from Product Recovery	Total Costs (with Revenue)
2024	$1,400	$27	$1,400	$170	$1,300
2025	$1,500	$57	$1,600	$290	$1,300
2026	$1,600	$88	$1,600	$380	$1,300
2027	$1,600	$120	$1,700	$460	$1,200
2028	$13,000	$1,500	$14,000	$1,100	$13,000
2029	$1,600	$1,500	$3,100	$1,200	$1,900
2030	$1,600	$1,500	$3,100	$1,300	$1,800
2031	$1,600	$1,500	$3,100	$1,300	$1,800
2032	$1,900	$1,500	$3,400	$1,300	$2,000
2033	$1,600	$1,400	$3,100	$1,400	$1,700
2034	$1,700	$1,400	$3,100	$1,400	$1,800
2035	$1,600	$1,400	$3,000	$1,400	$1,700
2036	$2,100	$1,400	$3,500	$1,400	$2,100
2037	$1,700	$1,400	$3,100	$1,400	$1,700
2038	$1,800	$1,400	$3,200	$1,400	$1,800

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

We now present the compliance costs of the final NSPS OOOOb and EG OOOOc in a PV framework. The stream of the estimated costs for each year from 2024 through 2038 is discounted back to 2021 using 2, 3, and 7 percent discount rates and summed to get the PV of the costs. The PV is then used to estimate the EAV of the estimated costs. The EAV is the single annual value which, if summed in PV terms across years in the analytical time frame, equals the PV of the original (i.e., likely time-varying) stream of costs. In other words, the EAV takes the potentially "lumpy" stream of costs and converts them into a single value that, when discounted and added together over each period in the analysis time frame, equals the original stream of values in PV terms.

Table 2-13 shows the discounted stream of costs discounted to 2021 using 2, 3, and 7 percent discount rates. The PV of the stream of costs discounted to 2021 using a 2 percent discount rate and accounting for product recovery is $19 billion, with an EAV of $2.1 billion per year. The PV of the stream of costs discounted to 2021 using a 3 percent discount rate and accounting for product recovery is $18 billion, with an EAV of $2 billion per year. The PV of the stream of costs discounted to 2021 using a 7 percent discount rate and accounting for product recovery is $14 billion, with an EAV of $1.5 billion per year.

Table 2-13 Discounted Projected Costs under the Final NSPS OOOOb and EG OOOOc Option, 2024–2038 (millions 2019$)

Year	2 Percent			3 Percent			7 Percent		
	Total Annual Cost (w/o Product Recovery Revenue)	Revenue from Product Recovery	Total Annual Costs (w/ Product Recovery Revenue)	Total Annual Cost (w/o Product Recovery Revenue)	Revenue from Product Recovery	Total Annual Costs (w/ Product Recovery Revenue)	Total Annual Cost (w/o Product Recovery Revenue)	Revenue from Product Recovery	Total Annual Cost (w/ Product Recovery Revenue)
2024	$130	$160	-$32	$130	$160	-$24	$140	$140	$3
2025	$270	$270	$1	$270	$260	$14	$280	$220	$60
2026	$400	$340	$61	$400	$330	$78	$400	$270	$130
2027	$530	$410	$130	$530	$380	$140	$500	$300	$200
2028	$2,800	$1,000	$1,800	$2,600	$930	$1,700	$2,300	$710	$1,600
2029	$2,800	$1,000	$1,700	$2,600	$950	$1,700	$2,200	$700	$1,500
2030	$2,800	$1,100	$1,700	$2,600	$960	$1,700	$2,100	$680	$1,400
2031	$2,800	$1,100	$1,700	$2,600	$970	$1,600	$2,000	$660	$1,400
2032	$2,700	$1,100	$1,700	$2,500	$960	$1,600	$1,900	$630	$1,300
2033	$2,700	$1,100	$1,700	$2,500	$950	$1,600	$1,800	$600	$1,200
2034	$2,700	$1,100	$1,600	$2,500	$930	$1,500	$1,700	$570	$1,200
2035	$2,700	$1,000	$1,700	$2,400	$910	$1,500	$1,700	$530	$1,100
2036	$2,700	$1,000	$1,700	$2,400	$890	$1,500	$1,600	$500	$1,100
2037	$2,700	$1,000	$1,700	$2,400	$870	$1,600	$1,500	$470	$1,100
2038	$2,700	$1,000	$1,700	$2,400	$860	$1,600	$1,500	$450	$1,000
PV	$31,000	$13,000	$19,000	$29,000	$11,000	$18,000	$22,000	$7,400	$14,000
EAV	$3,500	$1,400	$2,100	$3,200	$1,200	$2,000	$2,400	$950	$1,500

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding. Costs and revenue from product recovery in each year are discounted to 2021.

2.6 Comparison of Regulatory Alternatives

In this section, we compare the compliance cost and emissions impacts projected under the final rule with the results of two alternative regulatory scenarios, one less stringent and one more stringent than the final rule. The alternative scenarios focus on sources that account for the greatest quantities of estimated emissions reductions of methane for the final rule: fugitives, pneumatic devices, and associated gas, all in the production segment.

The alternative scenarios are summarized in Table 2-14. [a] The NSPS OOOOa established a standard of performance of 95% control for diaphragm pumps at well sites with existing combustion devices, which we do not include in our baseline due to a lack of information regarding which sites would be subject to the requirement. We believe this results in a slight overestimate of the impacts of the final rule and more stringent scenarios. In the less stringent scenario, we estimate the impacts of allowing sites with four or fewer controllers to convert all continuous bleed controllers to either zero or intermittent bleed controllers (our analysis assumes the latter occurs in all cases) and perform periodic inspections to detect and repair malfunctioning intermittent bleed controllers. In the more stringent scenario, we illustrate the impact of the small well site OGI exemption for by requiring well sites with a single piece of major equipment to perform semiannual OGI in addition to quarterly AVO. The more stringent scenario also estimates the impact of the associated gas emissions threshold in the EG OOOOc by requiring all sites to route to sales regardless of estimated associated gas methane emissions. These alternatives reflect key regulatory design alternatives that the EPA considered while developing the final rule.

Table 2-14 Summary of Regulatory Alternatives (Well Sites Only)

Source	Applicable NSPS	NSPS Baseline	Less Stringent	Final	More Stringent
Fugitive Emissions					
Single well site with a single price of major equipment and no tank battery	OOOOa	Semiannual OGI	Quarterly AVO	Quarterly AVO	Quarterly AVO + Semiannual OGI
Pneumatic Devices					
Sites with four or fewer controllers					
Continuous bleed controllers	OOOO	Natural gas bleed rate no greater than 6 scfh	Zero emissions or convert to intermittent bleed	Zero emissions	Zero emissions
Intermittent bleed controllers	None	No requirement	Inspection program	Zero emissions	Zero emissions
Pumps	OOOOa	No requirement[a]	No requirement	Zero emissions	Zero emissions
Associated Gas (EG Only)					
Sites with associated gas emissions less than 40 TPY CH_4	None	No requirement	95% control	95% control	Route to sales

[a] The NSPS OOOOa established a standard of performance of 95% control for diaphragm pumps at well sites with existing combustion devices, which we do not include in our baseline due to a lack of information regarding which sites would be subject to the requirement. We believe this results in a slight overestimate of the impacts of the final rule and more stringent scenarios.

A comparison of estimated costs and emissions reductions is presented in Table 2-15 for three years: 2024 (the first year of NSPS OOOOb impacts), 2028 (the first year of EG OOOOc impacts), and 2038 (the last year of analysis) across regulatory options. Overall, the table demonstrates that we estimate the emissions impacts to be similar across the three options. By the time the EG OOOOc is assumed to begin having an effect in 2028, we estimate that the less stringent option would result in roughly ten percent fewer methane emissions reductions of the finalized option, while reducing costs by a commensurate amount. On the other hand, we estimate that the more stringent option would result in only slightly more methane emissions reductions while costing significantly more than the finalized option.

Table 2-15 Comparison of Regulatory Alternatives in 2024, 2028, and 2038 for the Final NSPS OOOOb and EG OOOOc across Regulatory Options (millions 2019$)

	Regulatory Alternative		
	Less Stringent	**Final Rule**	**More Stringent**
		Total Impacts, 2024	
Emissions reductions			
Methane (short tons)	250,000	250,000	250,000
VOC (short tons)	76,000	77,000	77,000
Costs			
Annualized Costs without Product Recovery (3%)	$150	$150	$150
Annualized Costs with Product Recovery (3%)	-$27	-$27	-$27
		Total Impacts, 2028	
Emissions reductions			
Methane (short tons)	4,500,000	4,900,000	5,000,000
VOC (short tons)	1,200,000	1,300,000	1,300,000
Costs			
Annualized Costs without Product Recovery (3%)	$3,000	$3,300	$7,000
Annualized Costs with Product Recovery (3%)	$1,900	$2,100	$5,800
		Total Impacts, 2038	
Emissions reductions			
Methane (short tons)	4,900,000	5,200,000	5,300,000
VOC (short tons)	1,400,000	1,500,000	1,500,000
Costs			
Annualized Costs without Product Recovery (3%)	$3,800	$4,000	$6,300
Annualized Costs with Product Recovery (3%)	$2,500	$2,600	$4,900

2.7 Additional Information on Use of 2016 Oil and Gas ICR Data

The 2016 ICR data includes a survey of equipment at well sites and production characteristics of the wells at those sites. The data are cleaned and processed to generate estimates of the distribution of major equipment and storage vessels across sites which can be directly applied to our base year well site activity data as described in Section 2.2.1. The data processing steps, and a list of key assumptions made along the way, are summarized below.

The first step in the data cleaning procedure is to read in and remove duplicate and incomplete entries from the raw 2016 ICR data workbook. Well-level data comes from the sheets "Pt1WellsFromWebForms" and "Pt1WellsFromFileUploads", with corresponding site-level data sheets "Pt1WellSiteFromWebForms" and "Pt1WellSiteFromFileUploads". Data from both types of submissions are merged together to create two master raw data tables, one for wells and one for sites. For both types of data, duplicate entries were removed, first on the basis of having identical entries for all rows, and then on the basis of having identical well/wellsite IDs. For the latter, when the only difference is the submission time entry, we assume the last entry (chronologically) is the correct one. If submission time cannot be used to differentiate in the well-level data, we simply pick the first entry,[71] unless duplicate entries have different well types (oil or gas), in which case we drop the wells from the sample. Finally, we remove sites that do not produce gas or oil and choose the first entry for sites with entries that only differ by their latitude/longitude values.

The next step is to standardize key information in the well and wellsite data tables. Wells identified in the raw data as "active" or "producing" are grouped together. Likewise, wells identified as producing gas (wet, dry, or unknown) or coal bed methane are designated as gas wells, while wells identified as producing oil (light, heavy, or unknown) are designated as oil wells. Finally, wells are designated either as low production, non-low production, or unknown. For well sites, data on equipment counts are standardized such that counts are either left blank if valid information has not been provided, or equal to an integer (for separators, dehydrators, and compressors) or real (for tanks) value. Sites are further designated as having full equipment inventories if valid entries were provided for all equipment columns and partial equipment

[71] For non-unique wells with the same well type and submission time, the only difference is found in the "pt1_production_site_id" column, a distinction that we assume is meaningless for this exercise.

inventories if at least one equipment column has a valid entry and the remaining columns were left blank, in which case blank entries were designated as zeroes.

After data standardization, the well and wellsite data is merged to create as single dataset with information on equipment and production. The well-level data is aggregated to create site-level estimates of the number of wells for each combination of oil and gas and low and non-low production level; this step removes any well entries for which the production type and level is not known. The aggregated data is then merged with the wellsite data based on the native "operator_name" and "well_site_id_name" columns. To facilitate use with the well site activity data used for the impacts analysis, sites are then characterized as single well or multi-well sites, oil or gas sites (based on whether there are more oil or gas wells at the site, with ties designated as oil sites), and low or non-low production sites (only sites with exclusively low production wells were designated as low production sites). Then well sites are assigned to one of the 11 equipment categories and one of the two tank categories described in footnote .

Finally, the dataset is aggregated to calculate the proportion of sites and average equipment counts per well in each equipment/tank category. For the aggregate calculations, we include sites with full and partial equipment inventories. The results for well site proportions, stratified by production type and level and well count bin, are presented in Table 2-16. A significant portion of sites, particularly single wellhead oil sites, do not have any major equipment. Larger sites, both in terms of production levels and well counts, tend to have more equipment and tanks for both site types.

Table 2-16 Well Site Equipment/Tank Category Proportions Estimated From the 2016 ICR

	Gas				Oil			
	Low Production		Non-low Production		Low Production		Non-low Production	
Equipment/Tank Category	Single	Multi	Single	Multi	Single	Multi	Single	Multi
Major Equipment Count								
Zero	42%	19%	35%	2%	69%	33%	49%	10%
One	51%	33%	51%	10%	25%	46%	26%	8%
Two or More	7%	49%	14%	88%	6%	21%	24%	82%
Tanks Present								
No	61%	12%	46%	14%	61%	9%	51%	11%
Yes	39%	88%	54%	86%	39%	91%	49%	89%

The results for well site equipment averages, stratified by production level, well count bin, and equipment category, are presented in Table 2-17. Storage vessel averages are conditional on sites having at least one tank. Typically, non-low production sites tend to have more equipment and tanks than low production sites, particularly when it comes to separators, though the relationships is not unambiguous across all well type, well count bin, and equipment category permutations.

Table 2-17 Per-Site Average Equipment/Tank Counts Estimated From the 2016 ICR Well Site

Site Type	Production Level	Well Count Bin	Major Equipment Count	Equipment Count Per Site: Separators	Compressors	Dehydrators	Tanks
Gas	Low	Single	0	-	-	-	1.56
			1	0.98	0.01	0.01	
			2+	1.66	0.54	0.17	
		Multi	0	-	-	-	2.55
			1	0.96	0.02	0.02	
			2+	3.51	0.70	0.20	
	Non-Low	Single	0	-	-	-	1.80
			1	0.95	0.02	0.03	
			2+	1.82	0.50	0.19	
		Multi	0	-	-	-	3.62
			1	0.95	0.05	0.00	
			2+	4.09	0.30	0.09	
Oil	Low	Single	0	-	-	-	2.39
			1	0.98	0.02	0.00	
			2+	1.93	0.36	0.05	
		Multi	0	-	-	-	2.80
			1	0.99	0.01	0.00	
			2+	2.81	0.27	0.03	
	Non-Low	Single	0	-	-	-	4.36
			1	0.98	0.01	0.00	
			2+	2.22	0.51	0.06	
		Multi	0	-	-	-	8.27
			1	0.95	0.03	0.02	
			2+	4.39	0.48	0.07	

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3 BENEFITS

The final NSPS OOOOb and EG OOOOc are projected to reduce methane, VOC, and HAP emissions.[72] The total emissions reductions over the 2024 to 2038 period are estimated to be about 58 million short tons of methane, 16 million tons of VOC, and 590 thousand tons of HAP. The decrease in methane emissions in CO_2-equivalent (CO_2 Eq.) terms is estimated to be about 1.5 billion metric tons using a global warming potential of 28.

We monetize the impacts of methane reductions in this RIA. We estimate the climate benefits under the final rule using updated estimates of the social cost of methane (SC-CH_4), as presented in Section 3.2. Additionally, we monetize ozone-related health impacts of VOC reductions as presented in Section 3.3.

In addition to presenting monetized estimates of impacts from methane and VOC reductions, we also provide a qualitative discussion of potential climate, human health, and welfare impacts that we are unable to quantify and monetize in Sections 0 through 3.8. Table 3-1 summarizes the quantified and unquantified benefits in this analysis.

[72] Some control techniques projected to be used under the final rule, such as routing emission to combustion devices, are also anticipated to have minor disbenefits resulting from secondary emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), PM, carbon monoxide (CO), and total hydrocarbons (THC).

Table 3-1 Climate and Human Health Effects of the Projected Emissions Reductions under the Final Rule

Category	Effect	Effect Quantified	Effect Monetized	More Information
Environment				
Climate effects	Climate impacts from methane (CH_4)	—[a]	✓	Section 3.2
	Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts)	—	—	IPCC, Ozone ISA, PM ISA
Human Health				
Mortality from exposure to ozone[b]	Premature respiratory mortality from short-term exposure (0-99)	✓	✓	Ozone ISA
	Premature respiratory mortality from long-term exposure (age 30–99)	✓	✓	Ozone ISA
Nonfatal morbidity from exposure to ozone[b]	Hospital admissions—respiratory (ages 65-99)	✓	✓	Ozone ISA
	Emergency department visits—respiratory (ages 0-99)	✓	✓	Ozone ISA
	Asthma onset (0-17)	✓	✓	Ozone ISA
	Asthma symptoms/exacerbation (asthmatics age 5-17)	✓	✓	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[c]
	Metabolic effects (e.g., diabetes)	—	—	Ozone ISA[c]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[c]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[c]
	Reproductive and developmental effects	—	—	Ozone ISA[c]
Premature mortality from exposure to $PM_{2.5}$	Adult premature mortality from long-term exposure (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)	—	—	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)	—	—	PM ISA
	Stroke (ages 65-99)	—	—	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

Category	Effect	Effect Quantified	Effect Monetized	More Information
	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[c]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[c]
	Other nervous system effects (e.g., autism, cognitive decline, dementia)	—	—	PM ISA[c]
	Metabolic effects (e.g., diabetes)	—	—	PM ISA[c]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA[c]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[c]
Incidence of morbidity from exposure to HAP	Effects associated with exposure to hazardous air pollutants such as benzene	—	—	ATSDR, IRIS[d,e]

[a] The climate and related impacts of CH_4 emissions changes, such as sea level rise, are estimated within each integrated assessment model as part of the calculation of the SC-CH_4. The resulting monetized damages, which are relevant for conducting the benefit-cost analysis, are used in this RIA to estimate the welfare effects of quantified changes in methane emissions.
[b] Ozone benefits only quantified for ozone changes resulting from VOC reductions. Benefits associated with ozone changes resulting from CH_4 reductions are discussed qualitatively in this RIA.
[c] Not quantified due to data availability limitations and/or because current evidence is only suggestive of causality.
[d] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.
[e] We assess these benefits qualitatively due to data limitations for this analysis, but we have quantified them in other analyses.

3.1 Emissions Reductions

Oil and natural gas operations in the U.S. include a variety of emission sources for methane, VOC, and HAP, including wells, well sites, processing plants, compressor stations, storage equipment, and natural gas transmission and distribution lines. These emission points are located throughout much of the country, though many of these emissions sources are concentrated in particular geographic regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas natural gas compressor stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

Table 3-2 shows the emissions reductions projected under the final NSPS OOOOb and EG OOOOc over the 2024 to 2038 period. We present methane emissions in both short tons and

CO_2 Eq. using a global warming potential of 28. The impacts of these pollutants accrue at different spatial scales. HAP emissions increase exposure to carcinogens and other toxic pollutants primarily near the emission source. VOC emissions are precursors to secondary formation of $PM_{2.5}$ and ozone on a broader regional scale. Climate effects associated with long-lived greenhouse gases like methane generally do not depend on the location of the emission of the gas and have global impacts. Methane is also a precursor to global background concentrations of ozone.

Table 3-2 Projected Annual Reductions of Methane, VOC, and HAP Emission Reductions under the Final NSPS OOOOb and EG OOOOc, 2024–2038

Year	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)
2024	250,000	77,000	2,900	6,400,000
2025	490,000	150,000	5,600	12,000,000
2026	700,000	210,000	8,000	18,000,000
2027	900,000	270,000	10,000	23,000,000
2028	4,900,000	1,300,000	48,000	120,000,000
2029	4,900,000	1,300,000	49,000	130,000,000
2030	5,000,000	1,300,000	49,000	130,000,000
2031	5,000,000	1,300,000	50,000	130,000,000
2032	5,100,000	1,300,000	50,000	130,000,000
2033	5,100,000	1,400,000	51,000	130,000,000
2034	5,100,000	1,400,000	51,000	130,000,000
2035	5,100,000	1,400,000	52,000	130,000,000
2036	5,200,000	1,400,000	53,000	130,000,000
2037	5,200,000	1,400,000	54,000	130,000,000
2038	5,200,000	1,500,000	55,000	130,000,000
Total	58,000,000	16,000,000	590,000	1,500,000,000

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

3.2 Methane Climate Effects and Valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone, which also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice sheets, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

According to the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (IPCC, 2021b), radiative forcing due to methane relative to the year 1750 was 0.54 W/m^2 in 2019, which is about 16 percent of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after CO_2.[73] After accounting for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions account for about 0.5 degrees of warming today, or about one third of the total warming resulting from historical emissions of well-mixed GHGs.

The oil and natural gas sector emits significant quantities of methane. The U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990–2019 (published 2021) estimates 2019 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries, petroleum transportation, and natural gas distribution) to be 187 million metric tons CO_2 Eq. (U.S. EPA, 2021a). In 2019, total methane emissions from the oil and natural gas industry represented 27 percent of the total methane emissions from all sources and account for about 3 percent of all CO_2 Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions.

We estimate the climate benefits of CH_4 emissions reductions expected from the final rule using estimates of the social cost of methane (SC-CH_4) that reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies of Science, Engineering, and Medicine (National Academies, 2017). The EPA presented these estimates in a sensitivity analysis in the December 2022 RIA, solicited public comment on the methodology and use of these estimates, and has conducted an external peer review of these estimates, as described further below.

[73] Increased concentrations of methane and other well mixed greenhouse gases in the atmosphere absorb thermal infrared emission energy, reducing the rate at which the Earth can cool through radiating heat to space. Radiative forcing, measured as watts per square meter (W/m^2), is a measure of the climate impact of greenhouse gases and other human activities.

The SC-CH_4 is the monetary value of the net harm to society from emitting a metric ton of CH_4 into the atmosphere in a given year, or the benefit of avoiding that increase. In principle, SC-CH_4 is a comprehensive metric that includes the value of all future climate change impacts (both negative and positive), including changes in net agricultural productivity, human health effects, property damage from increased flood risk, changes in the frequency and severity of natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-CH_4, therefore, reflects the societal value of reducing CH_4 emissions by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CH_4 emissions. In practice, data and modeling limitations restrain the ability of SC-CH_4 estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Since 2008, the EPA has used estimates of the social cost of various greenhouse gases (i.e., social cost of carbon (SC-CO_2), social cost of methane (SC-CH_4), and social cost of nitrous oxide (SC-N_2O)), collectively referred to as the “social cost of greenhouse gases” (SC-GHG), in analyses of actions that affect GHG emissions. The values used by the EPA from 2009 to 2016, and since 2021 — including in the November 2021 RIA and December 2022 RIA for this rulemaking — have been consistent with those developed and recommended by the Interagency Working Group on the SC-GHG (IWG); and the values used from 2017 to 2020 were consistent with those required by E.O. 13783, which disbanded the IWG. During 2015–2017, the National Academies conducted a comprehensive review of the SC-CO_2 and issued a final report in 2017 recommending specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies, 2017). The IWG was reconstituted in 2021 and E.O. 13990 directed it to develop a comprehensive update of its SC-GHG estimates, recommendations regarding areas of decision-making to which SC-GHG should be applied, and a standardized review and updating process to ensure that the recommended estimates continue to be based on the best available economics and science going forward.

The EPA is a member of the IWG and is participating in the IWG's work under E.O. 13990. While that process continues, as noted in previous EPA RIAs, the EPA is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward.[74] In the December 2022 RIA, the Agency included a sensitivity analysis of the climate benefits of the Supplemental Proposal using a new set of SC-GHG estimates that incorporates recent research addressing recommendations of the National Academies (2017) in addition to using the interim SC-GHG estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* (IWG, 2021) that the IWG recommended for use until updated estimates that address the National Academies' recommendations are available.

The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, which explains the methodology underlying the new set of estimates, in the December 2022 Supplemental Proposal.[75] Please see the response to comments document for the rulemaking for summaries and responses to public comments. The response to comments document can be found in the docket for this action.

To ensure that the methodological updates adopted in the technical report are consistent with economic theory and reflect the latest science, the EPA also initiated an external peer review panel to conduct a high-quality review of the technical report, completed in May 2023. The peer reviewers commended the agency on its development of the draft update, calling it a much-needed improvement in estimating the SC-GHG and a significant step towards addressing the National Academies' recommendations with defensible modeling choices based on current science. The peer reviewers provided numerous recommendations for refining the presentation and for future modeling improvements, especially with respect to climate change impacts and associated damages that are not currently included in the analysis. Additional discussion of omitted impacts and other updates have been incorporated in the technical report to address peer

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[74] EPA strives to base its analyses on the best available science and economics, consistent with its responsibilities, for example, under the Information Quality Act.

[75] See https://www.epa.gov/environmental-economics/scghg for a copy of the final report and other related materials.

reviewer recommendations. Complete information about the external peer review, including the peer reviewer selection process, the final report with individual recommendations from peer reviewers, and the EPA's response to each recommendation is available on EPA's website.[76]

The remainder of this section provides an overview of the methodological updates incorporated into the SC-GHG estimates used in this RIA. A more detailed explanation of each input and the modeling process is provided in the technical report, *Supplementary Material for the RIA: EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* (U.S. EPA, 2023f), included in the docket.

The steps necessary to estimate the SC-GHG with a climate change integrated assessment model (IAM) can generally be grouped into four modules: socioeconomics and emissions, climate, damages, and discounting. The emissions trajectories from the socioeconomic module are used to project future temperatures in the climate module. The damage module then translates the temperature and other climate endpoints (along with the projections of socioeconomic variables) into physical impacts and associated monetized economic damages, where the damages are calculated as the amount of money the individuals experiencing the climate change impacts would be willing to pay to avoid them. To calculate the marginal effect of emissions, i.e., the SC-GHG in year t, the entire model is run twice – first as a baseline and second with an additional pulse of emissions in year t. After recalculating the temperature effects and damages expected in all years beyond t resulting from the adjusted path of emissions, the losses are discounted to a present value in the discounting module. Many sources of uncertainty in the estimation process are incorporated using Monte Carlo techniques by taking draws from probability distributions that reflect the uncertainty in parameters.

The SC-GHG estimates used by the EPA and many other federal agencies since 2009 have relied on an ensemble of three widely used IAMs: Dynamic Integrated Climate and Economy (DICE) (Nordhaus, 2010); Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) (Anthoff & Tol, 2013a, 2013b); and Policy Analysis of the Greenhouse Gas Effect (PAGE) (Hope, 2013). In 2010, the IWG harmonized key inputs across the IAMs, but all other model features were left unchanged, relying on the model developers' best estimates

[76] https://www.epa.gov/environmental-economics/scghg-tsd-peer-review

and judgments. That is, the representation of climate dynamics and damage functions included in the default version of each IAM as used in the published literature was retained.

The SC-GHG estimates in this RIA no longer rely on the three IAMs (i.e., DICE, FUND, and PAGE) used in previous SC-GHG estimates. Instead, EPA uses a modular approach to estimating the SC-GHG, consistent with the National Academies' (2017) near-term recommendations. That is, the methodology underlying each component, or module, of the SC-GHG estimation process is developed by drawing on the latest research and expertise from the scientific disciplines relevant to that component. Under this approach, each step in the SC-GHG estimation improves consistency with the current state of scientific knowledge, enhances transparency, and allows for more explicit representation of uncertainty.

The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income, and GHG emissions developed under the Resources for the Future (RFF) Social Cost of Carbon Initiative (Rennert, Prest, et al., 2022). These socioeconomic projections (hereafter collectively referred to as the RFF-SPs) are an internally consistent set of probabilistic projections of population, GDP, and GHG emissions (CO_2, CH_4, and N_2O) to 2300. Based on a review of available sources of long-run projections necessary for damage calculations, the RFF-SPs stand out as being most consistent with the National Academies' recommendations. Consistent with the National Academies' recommendation, the RFF-SPs were developed using a mix of statistical and expert elicitation techniques to capture uncertainty in a single probabilistic approach, taking into account the likelihood of future emissions mitigation policies and technological developments, and provide the level of disaggregation necessary for damage calculations. Unlike other sources of projections, they provide inputs for estimation out to 2300 without further extrapolation assumptions. Conditional on the modeling conducted for the SC-GHG estimates, this time horizon is far enough in the future to capture the majority of discounted climate damages. Including damages beyond 2300 would increase the estimates of the SC-GHG. As discussed in U.S. EPA (2023f), the use of the RFF-SPs allows for capturing economic growth uncertainty within the discounting module.

The climate module relies on the Finite Amplitude Impulse Response (FaIR) model (IPCC, 2021b; Millar et al., 2017; Smith et al., 2018), a widely used Earth system model which captures the relationships between GHG emissions, atmospheric GHG concentrations, and global mean surface temperature. The FaIR model was originally developed by Richard Millar, Zeb Nicholls, and Myles Allen at Oxford University, as a modification of the approach used in IPCC AR5 to assess the GWP and GTP (Global Temperature Potential) of different gases. It is open source, widely used (e.g., IPCC (2018, 2021a)), and was highlighted by the (National Academies, 2017) as a model that satisfies their recommendations for a near-term update of the climate module in SC-GHG estimation. Specifically, it translates GHG emissions into mean surface temperature response and represents the current understanding of the climate and GHG cycle systems and associated uncertainties within a probabilistic framework. The SC-GHG estimates used in this RIA rely on FaIR version 1.6.2 as used by the IPCC (2021a). It provides, with high confidence, an accurate representation of the latest scientific consensus on the relationship between global emissions and global mean surface temperature, offers a code base that is fully transparent and available online, and the uncertainty capabilities in FaIR 1.6.2 have been calibrated to the most recent assessment of the IPCC (which importantly narrowed the range of likely climate sensitivities relative to prior assessments). See U.S. EPA (2023f) for more details.

The socioeconomic projections and outputs of the climate module are inputs into the damage module to estimate monetized future damages from climate change.[77] The National Academies' recommendations for the damage module, scientific literature on climate damages, updates to models that have been developed since 2010, as well as the public comments received on individual EPA rulemakings and the IWG's February 2021 TSD, have all helped to identify available sources of improved damage functions. The IWG (e.g., IWG 2010, 2016a, 2021), the National Academies (2017), comprehensive studies (e.g., Rose et al. (2014)), and public comments have all recognized that the damages functions underlying the IWG SC-GHG estimates used since 2013 (taken from DICE 2010 (Nordhaus, 2010); FUND 3.8 (Anthoff & Tol,

[77] In addition to temperature change, two of the three damage modules used in the SC-GHG estimation require global mean sea level (GMSL) projections as an input to estimate coastal damages. Those two damage modules use different models for generating estimates of GMSL. Both are based off reduced complexity models that can use the FaIR temperature outputs as inputs to the model and generate projections of GMSL accounting for the contributions of thermal expansion and glacial and ice sheet melting based on recent scientific research. Absent clear evidence on a preferred model, the SC-GHG estimates presented in this RIA retain both methods used by the damage module developers. See U.S. EPA. (2023f). *Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Washington, DC: U.S. EPA for more details.

2013a, 2013b); and PAGE 2009 (Hope, 2013)) do not include all the important physical, ecological, and economic impacts of climate change. The climate change literature and the science underlying the economic damage functions have evolved, and DICE 2010, FUND 3.8, and PAGE 2009 now lag behind the most recent research.

The challenges involved with updating damage functions have been widely recognized. Functional forms and calibrations are constrained by the available literature and need to extrapolate beyond warming levels or locations studied in that literature. Research focused on understanding how these physical changes translate into economic impacts is still developing, and has received less public resources, relative to the research focused on modeling and improving our understanding of climate system dynamics and the physical impacts from climate change (Auffhammer, 2018). Even so, there has been a large increase in research on climate impacts and damages in the time since DICE 2010, FUND 3.8, and PAGE 2009 were published. Along with this growth, there continues to be variation in methodologies and scope of studies, such that care is required when synthesizing the current understanding of impacts or damages. Based on a review of available studies and approaches to damage function estimation, the EPA uses three separate damage functions to form the damage module. They are:

1. a subnational-scale, sectoral damage function (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (Carleton et al., 2022; Climate Impact Lab (CIL), 2023; Rode et al., 2021),

2. a country-scale, sectoral damage function (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF's Social Cost of Carbon Initiative (Rennert, Errickson, et al., 2022), and

3. a meta-analysis-based damage function (based on Howard and Sterner (2017)).

The damage functions in DSCIM and GIVE represent substantial improvements relative to the damage functions underlying the SC-GHG estimates used by the EPA to date and reflect the forefront of scientific understanding about how temperature change and SLR lead to monetized net (market and nonmarket) damages for several categories of climate impacts. The models' spatially explicit and impact-specific modeling of relevant processes allows for improved understanding and transparency about mechanisms through which climate impacts are occurring and how each damage component contributes to the overall results, consistent with the

National Academies' recommendations. DSCIM addresses common criticisms related to the damage functions underlying current SC-GHG estimates (e.g., Pindyck (2017)) by developing multi-sector, empirically grounded damage functions. The damage functions in the GIVE model offer a direct implementation of the National Academies' near-term recommendation to develop updated sectoral damage functions that are based on recently published work and reflective of the current state of knowledge about damages in each sector. Specifically, the National Academies noted that "[t]he literature on agriculture, mortality, coastal damages, and energy demand provide immediate opportunities to update the [models]" (National Academies 2017, p. 199), which are the four damage categories currently in GIVE. A limitation of both models is that the sectoral coverage is still limited, and even the categories that are represented are incomplete. Neither DSCIM nor GIVE yet accommodate estimation of several categories of temperature driven climate impacts (e.g., morbidity, conflict, migration, biodiversity loss) and only represent a limited subset of damages from changes in precipitation. For example, while precipitation is considered in the agriculture sectors in both DSCIM and GIVE, neither model takes into account impacts of flooding, changes in rainfall from tropical storms, and other precipitation related impacts. As another example, the coastal damage estimates in both models do not fully reflect the consequences of SLR-driven salt-water intrusion and erosion, or SLR damages to coastal tourism and recreation. Other missing elements are damages that result from other physical impacts (e.g., ocean acidification, non-temperature-related mortality such as diarrheal disease and malaria) and the many feedbacks and interactions across sectors and regions that can lead to additional damages.[78] See U.S. EPA (2023f) for more discussion of omitted damage categories and other modeling limitations. DSCIM and GIVE do account for the most commonly cited benefits associated with CO_2 emissions and climate change — CO_2 crop fertilization and declines in cold related mortality. As such, while the GIVE- and DSCIM-based results provide state-of-the-science assessments of key climate change impacts, they remain

[78] The one exception is that the agricultural damage function in DSCIM and GIVE reflects the ways that trade can help mitigate damages arising from crop yield impacts.

partial estimates of future climate damages resulting from incremental changes in CO_2, CH_4, and N_2O.[79]

Finally, given the still relatively narrow sectoral scope of the recently developed DSCIM and GIVE models, the damage module includes a third damage function that reflects a synthesis of the state of knowledge in other published climate damages literature. Studies that employ meta-analytic techniques offer a tractable and straightforward way to combine the results of multiple studies into a single damage function that represents the body of evidence on climate damages that pre-date CIL and RFF's research initiatives.[80] The first use of meta-analysis to combine multiple climate damage studies was done by Tol (2009) and included 14 studies. The studies in Tol (2009) served as the basis for the global damage function in DICE starting in version 2013R (Nordhaus, 2014). The damage function in the most recent published version of DICE, DICE 2016, is from an updated meta-analysis based on a rereview of existing damage studies and included 26 studies published over 1994-2013 (Nordhaus & Moffat, 2017). Howard and Sterner (2017) provide a more recent published peer-reviewed meta-analysis of existing damage studies (published through 2016) and account for additional features of the underlying studies. They address differences in measurement across studies by adjusting estimates such that the data are relative to the same base period. They also eliminate double counting by removing duplicative estimates. Howard and Sterner's final sample is drawn from 20 studies that were published through 2015. Howard and Sterner (2017) present results under several specifications, and their analysis shows that the estimates are somewhat sensitive to defensible alternative modeling choices. As discussed in detail in U.S. EPA (2023f), the damage module underlying the SC-GHG estimates in this RIA includes the damage function specification (that excludes duplicate studies) from Howard and Sterner (2017) that leads to the lowest SC-GHG estimates, all else equal.

[79] One advantage of the modular approach used by these models is that future research on new or alternative damage functions can be incorporated in a relatively straightforward way. DSCIM and GIVE developers have work underway on other impact categories that may be ready for consideration in future updates (e.g., morbidity and biodiversity loss).

[80] Meta-analysis is a statistical method of pooling data and/or results from a set of comparable studies of a problem. Pooling in this way provides a larger sample size for evaluation and allows for a stronger conclusion than can be provided by any single study. Meta-analysis yields a quantitative summary of the combined results and current state of the literature.

The discounting module discounts the stream of future net climate damages to its present value in the year when the additional unit of emissions was released. Given the long time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages. Consistent with the findings of National Academies (2017), the economic literature, OMB Circular A-4's guidance for regulatory analysis, and IWG recommendations to date (IWG, 2010, 2013, 2016a, 2016b, 2021), the EPA continues to conclude that the consumption rate of interest is the theoretically appropriate discount rate to discount the future benefits of reducing GHG emissions and that discount rate uncertainty should be accounted for in selecting future discount rates in this intergenerational context. OMB's Circular A-4 (2003) points out that "the analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption and to discount them at the rate consumers and savers would normally use in discounting future consumption benefits" (OMB, 2003).[81] The damage module described above calculates future net damages in terms of reduced consumption (or monetary consumption equivalents), and so an application of this guidance is to use the consumption discount rate to calculate the SC-GHG. Thus, EPA concludes that the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)), which does not reflect the consumption rate, to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG.[82]

For the SC-GHG estimates used in this RIA, EPA relies on a dynamic discounting approach that more fully captures the role of uncertainty in the discount rate in a manner consistent with the other modules. Based on a review of the literature and data on consumption discount rates, the public comments received on individual EPA rulemakings, and the February 2021 TSD (IWG, 2021), and the National Academies (2017) recommendations for updating the discounting module, the SC-GHG estimates rely on discount rates that reflect more recent data

[81] Similarly, OMB's Circular A-4 (2023) points out that "The analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption before discounting them" (OMB 2023).

[82] See also the discussion of the inappropriateness of discounting consumption-equivalent measures of benefits and costs using a rate of return on capital in Circular A-4 (2023) (OMB 2023).

on the consumption interest rate and uncertainty in future rates. Specifically, rather than using a constant discount rate, the evolution of the discount rate over time is defined following the latest empirical evidence on interest rate uncertainty and using a framework originally developed by Ramsey (1928) that connects economic growth and interest rates. The Ramsey approach explicitly reflects (1) preferences for utility in one period relative to utility in a later period and (2) the value of additional consumption as income changes. The dynamic discount rates used to develop the SC-GHG estimates applied in this RIA have been calibrated following the Newell et al. (2022) approach, as applied in Rennert, Errickson, et al. (2022); Rennert, Prest, et al. (2022). This approach uses the Ramsey (1928) discounting formula in which the parameters are calibrated such that (1) the decline in the certainty-equivalent discount rate matches the latest empirical evidence on interest rate uncertainty estimated by Bauer and Rudebusch (2020, 2023) and (2) the average of the certainty-equivalent discount rate over the first decade matches a near-term consumption rate of interest. Uncertainty in the starting rate is addressed by using three near-term target rates (1.5, 2.0, and 2.5 percent) based on multiple lines of evidence on observed market interest rates.

The resulting dynamic discount rate provides a notable improvement over the constant discount rate framework used for SC-GHG estimation in EPA RIAs to date. Specifically, it provides internal consistency within the modeling and a more complete accounting of uncertainty consistent with economic theory (Arrow et al., 2013; Cropper et al., 2014) and the National Academies' (2017) recommendation to employ a more structural, Ramsey-like approach to discounting that explicitly recognizes the relationship between economic growth and discounting uncertainty. This approach is also consistent with the National Academies (2017) recommendation to use three sets of Ramsey parameters that reflect a range of near-term certainty-equivalent discount rates and are consistent with theory and empirical evidence on consumption rate uncertainty. Finally, the value of aversion to risk associated with net damages from GHG emissions is explicitly incorporated into the modeling framework following the economic literature. See U.S. EPA (2023f) for a more detailed discussion of the entire discounting module and methodology used to value risk aversion in the SC-GHG estimates.

Taken together, the methodologies adopted in this SC-GHG estimation process allow for a more holistic treatment of uncertainty than in past estimates by the EPA. The updates incorporate a quantitative consideration of uncertainty into all modules and use a Monte Carlo approach that captures the compounding uncertainties across modules. The estimation process generates nine separate distributions of discounted marginal damages per metric ton – the product of using three damage modules and three near-term target discount rates – for each gas in each emissions year. These distributions have long right tails reflecting the extensive evidence in the scientific and economic literature that shows the potential for lower-probability but higher-impact outcomes from climate change, which would be particularly harmful to society. The uncertainty grows over the modeled time horizon. Therefore, under cases with a lower near-term target discount rate – that give relatively more weight to impacts in the future – the distribution of results is wider. To produce a range of estimates that reflects the uncertainty in the estimation exercise while also providing a manageable number of estimates for policy analysis, the EPA combines the multiple lines of evidence on damage modules by averaging the results across the three damage module specifications. The full results generated from the updated methodology for methane and other greenhouse gases (SC-CO_2, SC-CH_4, and SC-N_2O) for emissions years 2020 through 2080 are provided in U.S. EPA (2023f).

summarizes the resulting averaged certainty-equivalent SC-CH_4 estimates under each near-term discount rate that are used to estimate the climate benefits of the CH_4 emission reductions expected from the final rule. These estimates are reported in 2019 dollars but are otherwise identical to those presented in U.S. EPA (2023f). The SC-CH_4 increases over time within the models — i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2025 — because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

Table 3-3 Estimates of the Social Cost of CH_4, 2024–2038 (in 2019$ per metric ton CH_4)

	Near-Term Ramsey Discount Rate		
Year	**1.5%**	**2.0%**	**2.5%**
2024	$2,600	$1,900	$1,500
2025	$2,700	$2,000	$1,600
2026	$2,800	$2,100	$1,600
2027	$2,900	$2,200	$1,700
2028	$3,000	$2,200	$1,800
2029	$3,000	$2,300	$1,800
2030	$3,100	$2,400	$1,900
2031	$3,200	$2,500	$2,000
2032	$3,300	$2,500	$2,100
2033	$3,400	$2,600	$2,100
2034	$3,500	$2,700	$2,200
2035	$3,600	$2,800	$2,300
2036	$3,700	$2,900	$2,400
2037	$3,800	$3,000	$2,400
2038	$3,900	$3,100	$2,500

Source: U.S. EPA (2023f).
Note: These SC-CH_4 values are identical to those reported in the technical report U.S. EPA (2023f) adjusted for inflation to 2019 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA, 2021). The values are stated in $/metric ton CH_4 and vary depending on the year of CH_4 emissions. This table displays the values rounded to two significant figures. The annual unrounded values used in the calculations in this RIA are available in Appendix A.4 of U.S. EPA (2023f) and at: www.epa.gov/environmental-economics/scghg.

The methodological updates described above represent a major step forward in bringing SC-GHG estimation closer to the frontier of climate science and economics and address many of the National Academies' (2017) near-term recommendations. Nevertheless, the resulting SC-GHG estimates, including the SC-CH4 estimates presented in Table 3-3, still have several limitations, as would be expected for any modeling exercise that covers such a broad scope of scientific and economic issues across a complex global landscape. There are still many categories of climate impacts and associated damages that are only partially or not reflected yet in these estimates and sources of uncertainty that have not been fully characterized due to data and modeling limitations. For example, the modeling omits most of the consequences of changes in precipitation, damages from extreme weather events, the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of GHG emissions. The SC-CH_4 estimates do not account for the direct health and welfare impacts associated with tropospheric ozone produced by methane. As discussed further in U.S. EPA (2023f) and in Section 3.6 of this RIA, recent studies have found the global ozone-related respiratory mortality benefits of CH_4 emissions reductions, which are not included in the SC-CH4 values presented in Table 3-3, to be, in 2019 dollars, approximately $2,400 per metric ton of methane emissions in 2030 (McDuffie et al., 2023). In addition, the SC-CH_4 estimates do not reflect that methane emissions lead to a reduction in atmospheric oxidants, like hydroxyl radicals, nor do they account for impacts associated with CO_2 produced from methane oxidizing in the atmosphere. Importantly, the updated SC-GHG methodology does not yet reflect interactions and feedback effects within, and across, Earth and human systems. For example, it does not explicitly reflect potential interactions among damage categories, such as those stemming from the interdependencies of energy, water, and land use. These, and other, interactions and feedbacks were highlighted by the National Academies as an important area of future research for longer-term enhancements in the SC-GHG estimation framework.

Table 3-4 presents the undiscounted annual monetized climate benefits under the final NSPS OOOOb and EG OOOOc. Projected methane emissions reductions each year are multiplied by the SC-CH_4 estimate for that year.[83] Table 3-5 shows the annual climate benefits discounted back to 2021 and the PV and the EAV for the 2024–2038 period under each discount rate. In this analysis, to calculate the present and annualized values of climate benefits, EPA uses the same discount rate as the near-term target Ramsey rate used to discount the climate benefits from future CH_4 reductions. That is, future climate benefits estimated with the SC-CH_4 at the near-term 2 percent Ramsey rate are discounted to the base year of the analysis using the same 2 percent rate.[84]

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[83] The EPA has also applied its updated estimates of the social cost of carbon dioxide (SC-CO_2) in an illustrative analysis of potential climate disbenefits from secondary CO_2 emissions associated with particular control techniques to meet the storage vessel-related standards. Given that the estimated climate disbenefits from the CO_2 impacts would at most offset only about 1 percent of the methane benefits, the EPA finds that the summary values shown in Tables 3-4 and 3-5 are a reasonable estimate of the net monetized climate effects of the rule. See Section 3.9 for further discussion.

[84] As discussed in U.S. EPA. (2023f). *Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Washington, DC: U.S. EPA, the error associated with using a constant discount rate rather than the certainty-equivalent rate path to calculate the present value of a future stream of monetized climate benefits is small for analyses with moderate time frames (e.g., 30 years or less). Ibid. also provides an illustration of the amount that climate benefits from reductions in future emissions will be underestimated by using a constant discount rate relative to the more complicated certainty-equivalent rate path.

Table 3-4 Undiscounted Monetized Climate Benefits under the Final NSPS OOOOb and EG OOOOc, 2024–2038 (millions, 2019$)

	Undiscounted[a]		
Year	**1.5%**	**2.0%**	**2.5%**
2024	$600	$440	$340
2025	$1,200	$890	$700
2026	$1,800	$1,300	$1,000
2027	$2,300	$1,700	$1,400
2028	$13,000	$9,900	$7,900
2029	$14,000	$10,000	$8,200
2030	$14,000	$11,000	$8,600
2031	$15,000	$11,000	$9,000
2032	$15,000	$12,000	$9,400
2033	$16,000	$12,000	$9,900
2034	$16,000	$13,000	$10,000
2035	$17,000	$13,000	$11,000
2036	$18,000	$14,000	$11,000
2037	$18,000	$14,000	$12,000
2038	$19,000	$15,000	$12,000

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using updated estimates of the SC-CH_4 from U.S. EPA (2023f).

Table 3-5 Discounted Monetized Climate Benefits under the Final NSPS OOOOb and EG OOOOc, 2024–2038 (millions, 2019$)

	Discounted back to 2021[a]		
Year	**1.5%**	**2.0%**	**2.5%**
2024	$570	$410	$320
2025	$1,100	$820	$630
2026	$1,600	$1,200	$920
2027	$2,100	$1,600	$1,200
2028	$12,000	$8,600	$6,600
2029	$12,000	$8,800	$6,700
2030	$12,000	$9,000	$6,900
2031	$13,000	$9,200	$7,000
2032	$13,000	$9,400	$7,200
2033	$13,000	$9,600	$7,300
2034	$13,000	$9,700	$7,400
2035	$14,000	$9,900	$7,500
2036	$14,000	$10,000	$7,700
2037	$14,000	$10,000	$7,800
2038	$15,000	$10,000	$7,900
PV	$150,000	$110,000	$83,000
EAV	$11,000	$8,500	$6,700

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using updated estimates of the SC-CH_4 from U.S. EPA (2023f).

Unlike many environmental problems where the causes and impacts are distributed more locally, GHG emissions are a global externality making climate change a true global challenge. GHG emissions contribute to damages around the world regardless of where they are emitted. Because of the distinctive global nature of climate change, in the RIA for this final rule the EPA centers attention on a global measure of climate benefits from CH_4 reductions. Consistent with all IWG recommended SC-GHG estimates to date, the SC-CH_4 values presented in Table 3-3 provide a global measure of monetized damages from CH_4 emissions, and Tables 3-4 and 3-5 present the monetized global climate benefits of the CH_4 emission reductions expected from the final rule. This approach is the same as that taken in EPA regulatory analyses from 2009 through 2016 and since 2021. It is also consistent with guidance in OMB Circular A-4 (2003) that states when a regulation is likely to have international effects, “these effects should be reported”.[85] EPA also notes that EPA’s cost estimates in RIAs, including the cost estimates contained in this RIA, regularly do not differentiate between distinguish and segregate the share of compliance costs expected to accrue to U.S. firms versus foreign interests, such as to foreign investors in regulated entities.[86] A global perspective on climate effects is therefore consistent with the approach EPA takes on costs. There are many reasons, as summarized in this section — and as articulated by OMB and in IWG assessments (IWG 2010, 2013, 2016a, 2016b, 2021), the 2015 Response to Comments (IWG 2015), and in detail in EPA (2023e) and in Appendix A of the Response to Comments document for this action — why the EPA focuses on the global value of climate change impacts when analyzing policies that affect GHG emissions.

International cooperation and reciprocity are essential to successfully addressing climate change, as the global nature of greenhouse gases means that a ton of GHGs emitted in any other country harms those in the U.S. just as much as a ton emitted within the territorial U.S. Assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. This is a classic public goods problem because each country’s reductions benefit everyone else, and no country can be excluded from enjoying the benefits of

[85] While OMB Circular A-4 (2003) recommends that international effects be reported separately, the guidance also explains that “[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues.” (OMB 2003). Circular A-4 (2023) states that “In certain contexts, it may be particularly appropriate to include effects experienced by noncitizens residing abroad in your primary analysis. Such contexts include, for example, when:

- assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. citizens and residents that are difficult to otherwise estimate;
- assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. national interests that are not otherwise fully captured by effects experienced by particular U.S. citizens and residents (e.g., national security interests, diplomatic interests, etc.);
- regulating an externality on the basis of its global effects supports a cooperative international approach to the regulation of the externality by potentially inducing other countries to follow suit or maintain existing efforts; or
- international or domestic legal obligations require or support a global calculation of regulatory effects”

(OMB 2023).

[86] For example, in the RIA for the 2018 Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources, the EPA acknowledged that some portion of regulatory costs will likely “accru[e] to entities outside U.S. borders” through foreign ownership, employment, or consumption (EPA 2018, p. 3-13). In general, a significant share of U.S. corporate debt and equities are foreign-owned, including in the oil and gas industry.

other countries' reductions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis — and so benefit the U.S. and its citizens and residents — is for *all* countries to base their policies on global estimates of damages. A wide range of scientific and economic experts have emphasized the issue of international cooperation and reciprocity as support for assessing global damages of GHG emission in domestic policy analysis. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to also assess global climate damages of their policies and to take steps to reduce emissions. For example, many countries and international institutions have already explicitly adapted the global SC-GHG estimates used by EPA in their domestic analyses (e.g., Canada, Israel) or developed their own estimates of global damages (e.g., Germany), and recently, there has been renewed interest by other countries to update their estimates since the draft release of the updated SC-GHG estimates presented in the December 2022 Supplemental Proposal RIA.[87] Several recent studies have empirically examined the evidence on international GHG mitigation reciprocity, through both policy diffusion and technology diffusion effects. See U.S. EPA (2023f) for more discussion.

For all of these reasons, the EPA believes that a global metric is appropriate for assessing the climate benefits of avoided methane emissions in this final RIA. In addition, as emphasized in the National Academies (2017) recommendations, "[i]t is important to consider what constitutes a domestic impact in the case of a global pollutant that could have international implications that impact the United States." The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need to be considered when evaluating the benefits of GHG mitigation to U.S. citizens and residents. The increasing interconnectedness of global economy and populations means that impacts occurring outside of U.S. borders can have significant impacts on U.S. interests. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political

[87] In April 2023, the government of Canada announced the publication of an interim update to their SC-GHG guidance, recommending SC-GHG estimates identical to the EPA's updated estimates presented in the December 2022 Supplemental Proposal RIA. The Canadian interim guidance will be used across all federal departments and agencies, with the values expected to be finalized by the end of the year. https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html.

destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Those impacts point to the global nature of the climate change problem and are better captured within global measures of the social cost of greenhouse gases.

In the case of this global pollutant, for the reasons articulated in this section, the assessment of global net damages of GHG emissions allows EPA to fully disclose and contextualize the net climate benefits of the CH_4 emission reductions expected from this final rule. The EPA disagrees with commenters who suggest that the EPA can or should use a metric focused on benefits resulting solely from changes in climate impacts occurring within U.S. borders. The global models used in the SC-GHG modeling described above do not lend themselves to be disaggregated in a way that could provide comprehensive information about the distribution of the rule's climate benefits to citizens and residents of particular countries, or population groups across the globe and within the U.S. Two of the models used to inform the damage module, the GIVE and DSCIM models, have spatial resolution that allows for some geographic disaggregation of a subset of climate impacts across the world. This permits the calculation of a partial GIVE and DSCIM-based SC-GHG measuring the damages from four or five climate impact categories (respectively) projected to physically occur within the U.S., subject to caveats. As discussed at length in U.S. EPA (2023f) these damage modules are only a partial accounting and do not capture many significant pathways through which climate change affects public health and welfare. For example, this modeling omits most of the consequences of changes in precipitation, damages from extreme weather events (e.g., wildfires), the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of GHG emissions other than CO_2 fertilization (e.g., tropospheric ozone formation due to CH_4 emissions). Thus, this modeling only cover a subset of potential climate change impacts. Furthermore, the damage modules do not capture spillover or indirect effects whereby climate impacts in one country or region can affect the welfare of residents in other countries or regions — for example through the movement of refugees.

Additional modeling efforts can and have shed further light on some omitted damage categories. For example, the Framework for Evaluating Damages and Impacts (FrEDI) is an open-source modeling framework developed by the EPA to facilitate the characterization of net annual climate change impacts in numerous impact categories within the contiguous U.S. and monetize the associated distribution of modeled damages (Sarofim et al., 2021; U.S. EPA, 2021c).[88] The additional impact categories included in FrEDI reflect the availability of U.S.-specific data and research on climate change effects. As discussed in U.S. EPA (2023f), results from FrEDI show that annual damages resulting from climate change impacts within the contiguous U.S. (CONUS) (i.e., excluding Hawaii, Alaska, and U.S. territories) and for impact categories not represented in GIVE and DSCIM are expected to be substantial. For example, FrEDI estimates a partial SC-CH_4 of \$590/mtCH_4 for damages physically occurring within CONUS for 2030 emissions (under a 2 percent near-term Ramsey discount rate) (Hartin et al., 2023), compared to a GIVE and DSCIM-based U.S.-specific SC-CH_4 of \$280/mtCH_4 and \$75/mtCH_4, respectively, for 2030 emissions. While the FrEDI results help to illustrate how monetized damages physically occurring within CONUS increase as more impacts are reflected in the modeling framework, they are still subject to many of the same limitations associated with the DSCIM and GIVE damage modules, including the omission or partial modeling of important damage categories.[89] Finally, none of these modeling efforts — GIVE, DSCIM, and FrEDI — reflect non-climate mediated effects of GHG emissions experienced by U.S. populations (other than CO_2 fertilization effects on agriculture). As one example of new research on non-climate

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[88] The FrEDI framework and Technical Documentation have been subject to a public review comment period and an independent external peer review, following guidance in the EPA Peer-Review Handbook for Influential Scientific Information (ISI). Information on the FrEDI peer-review is available at the EPA Science Inventory EPA Science Inventory. (2021). *Technical Documentation on The Framework for Evaluating Damages and Impacts (FrEDI)*. Retrieved February 16, 2023 from https://cfpub.epa.gov/si/si_public_record_report.cfm?dirEntryId=351316&Lab=OAP&simplesearch=0&showcriteria=2&sortby=pubDate&searchall=fredi&timstype=&datebeginpublishedpresented=02/14/2021.

[89] Another method that has produced estimates of the effect of climate change on U.S.-specific outcomes uses a top-down approach to estimate aggregate damage functions. Published research using this approach include total-economy empirical studies that econometrically estimate the relationship between GDP and a climate variable, usually temperature. As discussed in U.S. EPA. (2023f). *Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Washington, DC: U.S. EPA, the modeling framework used in the existing published studies using this approach differ in important ways from the inputs underlying the SC-GHG estimates described above (e.g., discounting, risk aversion, and scenario uncertainty) and focus solely on CO_2. Hence, we do not consider this line of evidence in the analysis for this RIA. Updating the framework of total-economy empirical damage functions to be consistent with the methods described in this RIA and ibid. would require new analysis. Finally, because total-economy empirical studies estimate market impacts, they do not include non-market impacts of climate change (e.g., mortality impacts) and therefore are also only a partial estimate. The EPA will continue to review developments in the literature and explore ways to better inform the public of the full range of GHG impacts.

mediated effects of methane emissions, McDuffie et al. (2023) estimate the monetized increase in respiratory-related human mortality risk from the ozone produced from a marginal pulse of methane emissions. Using the socioeconomics from the RFF-SPs and the 2 percent near-term Ramsey discounting approach, this additional risk to U.S. populations is on the order of approximately \$320/mtCH_4 for 2030 emissions (U.S. EPA 2023e).

Taken together, applying the U.S.-specific partial SC-CH_4 estimates derived from the evidence described above to the CH_4 emissions reduction expected under the final rule would yield substantial benefits. For example, the present value of the climate benefits of the final rule as measured by FrEDI using additional U.S.-specific data and research on climate change impacts in CONUS are estimated to be \$27 billion (under a 2 percent near-term Ramsey discount rate.[90] However, even with these additional impact categories, the numerous explicitly omitted damage categories and other modeling limitations discussed above and throughout U.S. EPA (2023f) make it likely that these estimates underestimate the benefits to U.S. citizens and residents of the CH_4 reductions from the final rule; the limitations in developing a U.S.-specific estimate that accurately captures direct and spillover effects on U.S. citizens and residents further demonstrates that it is more appropriate to use a global measure of climate benefits from CH_4 reductions. The EPA will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of GHG impacts.

3.3 Ozone-Related Health Impacts Due to VOC Emissions Changes

Human exposure to ambient ozone concentrations is associated with adverse health effects, including premature respiratory mortality and cases of respiratory morbidity (U.S. EPA, 2020c). Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical, and epidemiological studies ozone (U.S. EPA, 2020c). When adequate data and resources are available, the EPA has generally quantified several health effects associated with exposure to ozone (U.S. EPA, 2011c, 2015, 2023c). These health effects include

[90] DCIM and GIVE use global damage functions. Damage functions based on only U.S.-data and research, but not for other parts of the world, were not included in those models. FrEDI does make use of some of this U.S.-specific data and research and as a result has a broader coverage of climate impact categories.

respiratory morbidity, such as asthma attacks, hospital and emergency department visits, lost school days, and premature respiratory mortality. The scientific literature is also suggestive that exposure to ozone is associated with chronic respiratory damage and premature aging of the lungs.

This final rulemaking is projected to reduce volatile organic compounds (VOC) emissions, which are a precursor to ozone. Ozone is not generally emitted directly into the atmosphere but is created when its two primary precursors, VOC and oxides of nitrogen (NO_X), react in the atmosphere in the presence of sunlight. In urban areas, compounds representing all classes of VOC can be important for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in some non-urban vegetated areas (U.S. EPA, 2013). Recent observational and modeling studies have found that VOC emissions from oil and natural gas operations can impact ozone levels (Helmig, 2020; Kemball-Cook et al., 2010; Lindaas et al., 2019; Lyu et al., 2021; McDuffie et al., 2016; Pozzer et al., 2020; Reddy, 2023; Tzompa-Sosa & Fischer, 2021). As shown later in this section, VOC emissions reductions from this rulemaking are expected decrease ozone formation, human exposure to ozone, and the incidence of ozone-related health effects.

This section describes the methods used to estimate the benefits to human health of reducing concentrations of ozone from this rule. This analysis uses methodology for determining air quality changes that has been used in the RIAs from multiple previous proposed and final rules (U.S. EPA, 2019b, 2020a, 2020b, 2021b, 2022b, 2023d, 2023e). The health benefits analysis uses the spatial fields of air quality across the U.S. described in Section 3.3.1 in BenMAP-CE to quantify the benefits under each regulatory alternative compared to the baseline and for four analytical years: 2024, 2027, 2028 and 2038. Health benefit analyses were also run for each year between 2024 and 2038, using the model surfaces for 2024, 2027, 2028 and 2038 as described in Section 3.3.1, but accounting for the change in population size in each year, income growth and baseline mortality incidence rates at five-year increments. Specifically, the analysis quantifies health benefits resulting from changes in ozone concentrations in 2024, 2027, 2028 and 2038 for each of the scenarios (i.e., finalized rule, less stringent scenario, and more stringent scenario). The methods for quantifying the number and value of air pollution-attributable premature deaths and illnesses are described in the Technical Support Document

(TSD) titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* (U.S. EPA, 2023b) and further referred to as the Health Benefits TSD in this RIA.

Estimating the health benefits of reductions in ozone exposure begins with estimating the change in exposure for each individual and then estimating the change in each individual's risks for 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.

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) developing spatial fields of air quality for a baseline, the finalized rule, a less stringent scenario, and a more stringent scenario (2) selecting air pollution health endpoints to quantify; (3) calculating counts of air pollution effects using a health impact function; (4) specifying the health impact function with concentration-response parameters drawn from the epidemiological literature to calculate the economic value of the health impacts. We estimate the quantity and economic value of air pollution-related effects using a "damage-function." This approach quantifies counts of air pollution-attributable cases of adverse health outcomes and assigns dollar values to those counts, while assuming that each outcome is independent of one another.

As structured, the final rules would affect the distribution of ozone concentrations in much of the U.S. This RIA estimates avoided ozone-related health impacts that are distinct from those reported in the RIAs for the ozone NAAQS ozone (U.S. EPA, 2015). The ozone NAAQS RIAs illustrates, 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. The benefit estimates are based on these modeled changes in summer season average ozone concentrations for each of the years 2024, 2027, 2028 and 2038.

3.3.1 Developing Air Quality Surfaces of Ozone Impacts from VOC Emissions Changes

As described above, the final rules influence the level of VOCs, a precursor to ground-level ozone formation, emitted in the atmosphere. The methods for determining VOC emissions associated with the baseline, final policy, and more and less stringent regulatory alternatives are described in Section 2.2. A map of state-level VOC emissions reductions associated with the final rules used in the creation of the ozone surfaces is provided in Figure 3-1.[91]

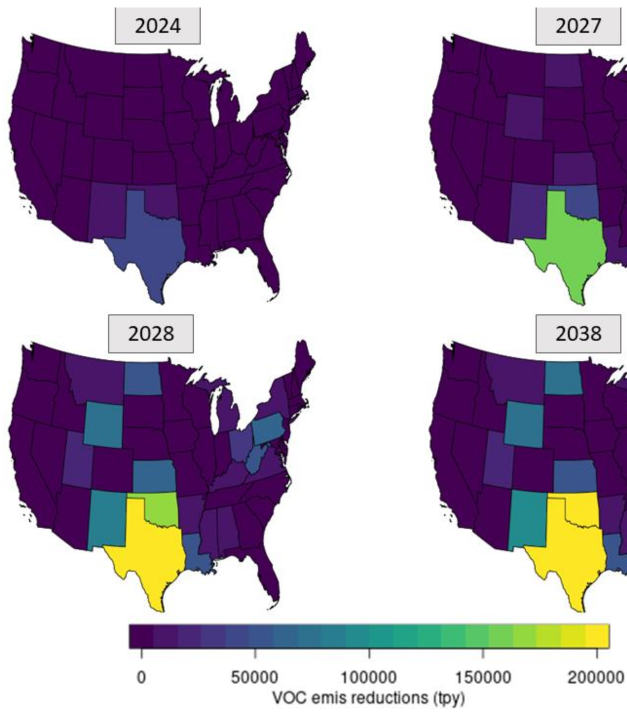

Figure 3-1 Map of State-level VOC Emissions Reductions (tpy) from the Baseline to the Final Rule Scenario in 2024, 2027, 2028 and 2038
Note: the projected emissions reductions in Texas for 2028 and in Oklahoma and Texas in 2038 are above the top of the color scale at approximately 572,000 tpy, 202,000 tpy and 684,000 tpy respectively.

The EPA used air quality modeling to estimate changes in summertime ozone concentrations that may result from the regulatory alternatives relative to the baseline in four

[91] The VOC emissions levels used to quantify ozone benefits were calculated based on the best understanding of the policy at the time of the analysis. While some updates to the policy were made after the ozone benefits analysis was completed, the impact on VOC emissions was less than 0.05% for the final rule scenario and therefore would not meaningfully impact the quantified ozone benefits.

years of analysis.[92] Gridded spatial fields of April through September seasonal average 8-hour daily maximum (MDA8) ozone (AS-MO3) concentrations representing the baseline and regulatory alternatives were derived from CAMx source apportionment modeling in combination with the VOC emissions described in Section 2.2 of this RIA and shown in Figure 3-1. These ozone gridded spatial fields cover all locations in the contiguous U.S. and were used as inputs to BenMAP-CE which, in turn, was used to quantify the benefits from this rule.[93] Figure 3-2 shows the geographical distribution of ozone changes in the final rules relative to the baseline in the four years of analysis. The basic methodology for determining air quality changes is the same as that used in the RIAs from multiple previous rulemakings (U.S. EPA, 2019b, 2020a, 2020b, 2021b, 2022b, 2023d, 2023e). U.S. EPA (2023) provides additional details on the air quality modeling and the methodologies EPA used to develop gridded spatial fields of summertime ozone concentrations for this analysis.

[92] The air quality modeling was conducted using emissions projected to the year 2026. The ozone surfaces reflecting the baseline and regulatory alternatives in 2024, 2027, 2028, and 2038 adjust ozone impacts from oil and gas sources to reflect expected VOC emissions from those sources in each of those year. Emissions from all other sources are held constant at 2026 levels.

[93] Given the regional nature of ozone pollution, it is possible, as depicted in Figure 3-2, that areas outside the contiguous U.S. may also experience reductions in ozone concentrations, and associated health and environmental benefits, resulting from this rule, including in portions of Mexico and Canada. This RIA does not quantify those additional health and environmental effects.

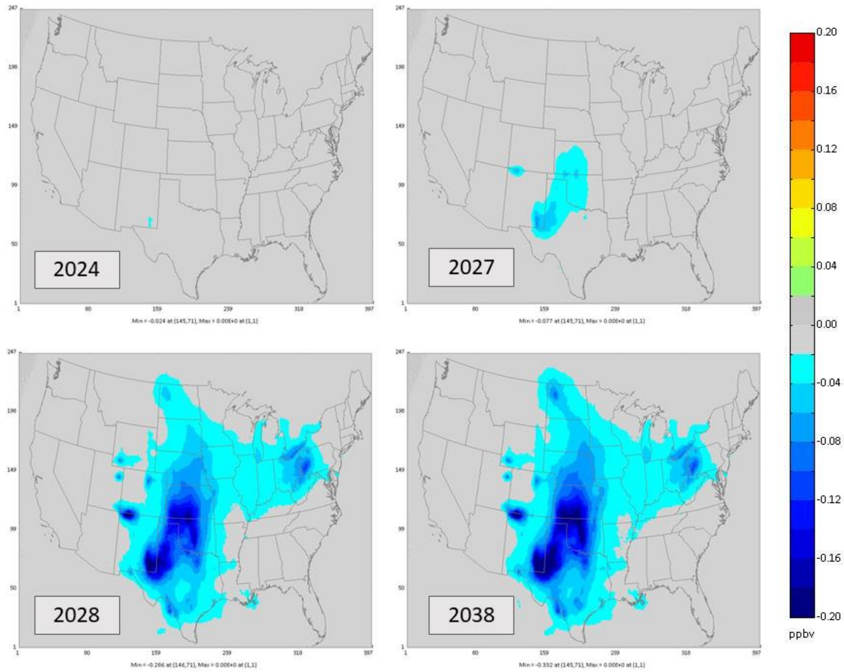

Figure 3-2 Map of Modeled Changes in April to September MDA8 Ozone Concentrations Calculated as the Final Rule Scenario Minus the Baseline Scenario in 2024, 2027, 2028 and 2038

3.3.2 Selecting Air Pollution Health Endpoints to Quantify

As a first step in quantifying ozone-related human health impacts, the Agency consults the Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Ozone ISA) (U.S. EPA, 2020c). The Ozone ISA synthesizes the toxicological, clinical, and epidemiological Evidence to determine whether ozone 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. Historically, the Agency estimates the incidence of air pollution effects for those health endpoints that the ISA classified as either causal or likely-to-be-causal. The analysis also accounts for recommendations from the Science Advisory Board (U.S. EPA Science Advisory Board, 2019, 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. The Health Benefits TSD fully describes 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.[94]

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. Table 3-1 reports the ozone-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. Sections 0 through report other non-quantified health and environmental benefits expected from the emissions and effluent changes as a result of this rule, such as health effects associated with $PM_{2.5}$, NO_2 and SO_2, and any welfare effects such as acidification and nutrient enrichment.

Consistent with economic theory, the willingness-to-pay (WTP) for reductions in exposure to environmental hazards will depend on the expected impact of those reductions on human health and other outcomes. All else equal, WTP is expected to be higher when there is stronger evidence of a causal relationship between exposure to the contaminant and changes in a health outcome (McGartland et al., 2017). For example, in the case where there is no evidence of a potential relationship the WTP would be expected to be zero and the effect should be excluded from the analysis. Alternatively, when there is some evidence of a relationship between exposure

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

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 (Kivi & Shogren, 2010; U.S. EPA Science Advisory Board, 2020b). 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 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.[95] All else equal, this approach may underestimate the benefits of 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.[96] 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. Table 3-1 reports the effects we quantified and those we did not quantify in this RIA. The list of benefit categories not quantified is not exhaustive and omits welfare effects such as acidification and nutrient enrichment.

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[95] 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 section 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.

[96] 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 (Health Benefits TSD section 6.2.3).

3.3.3 Calculating Counts of Air Pollution Effects Using the Health Impact Function

We use the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) software program to quantify counts of premature deaths and illnesses attributable to photochemical modeled changes in summer season average ozone concentrations for the years 2024, 2027, 2028, and 2038 using health impact functions (Sacks et al., 2020). A health impact function combines information regarding: the concentration-response relationship between air quality changes and the risk of a given adverse outcome; the population exposed to the air quality change; the baseline rate of death or disease in that population; and the air pollution concentration to which the population is exposed.

BenMAP quantifies counts of attributable effects using health impact functions, which combine 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 among adults aged 18 and older (a) in each county in the contiguous U.S. j (j=1,…,J where J is the total number of counties) as

$$y_{ij} = \Sigma a \; y_{ij}a$$

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

where mo_{ija} is the baseline total mortality rate for adults aged a=18-99 in county j in year i stratified in 10-year age groups, β is the risk coefficient for total 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=18-99 in county j in year i stratified into 5-year age groups.[97]

[97] In this illustrative example, the air quality is resolved at the county level. For this RIA, we simulate air quality concentrations at 12 km grid resolution. The BenMAP-CE tool assigns the rates of baseline death and disease stored at the county level to the grid cell level using an area-weighted algorithm. This approach is described in greater detail in the appendices to the BenMAP-CE user manual (U.S. EPA, 2023a).

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.

To assess economic value in a damage-function framework, the changes in environmental quality must be translated into effects on people or on the things that people value. In some cases, the changes in environmental quality can be directly valued. In other cases, such as for changes in ozone, a health and welfare impact analysis must first be conducted to convert air quality changes into effects that can be assigned dollar values.

We note at the outset that EPA rarely has the time or resources to perform extensive new research to measure directly either the health outcomes or their values for regulatory analyses. Thus, similar to Künzli et al. (2000) and other, more recent health impact analyses, our estimates are based on the best available methods of benefits transfer. Benefits transfer adapts primary research from similar contexts to obtain the most accurate measure of benefits for the environmental quality change under analysis. Adjustments are made for the level of environmental quality change, the socio-demographic and economic characteristics of the affected population, and other factors to improve the accuracy and robustness of benefits estimates.

3.3.4 Calculating the Economic Valuation of Health Impacts

After quantifying the change in adverse health impacts, the final step is to estimate the economic value of these avoided impacts. The appropriate economic value for a change in a health effect depends on whether the health effect is viewed ex ante (before the effect has occurred) or ex post (after the effect has occurred). Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health effects by a small amount for a large population. The appropriate economic measure is therefore ex ante WTP for changes in risk.

However, epidemiological studies generally provide estimates of the relative risks of a particular health effect avoided due to a reduction in air pollution. A convenient way to use these data in a consistent framework is to convert probabilities to units of avoided statistical incidences. This measure is calculated by dividing individual WTP for a risk reduction by the related observed change in risk. For example, suppose a regulation reduces the risk of premature mortality from 2 in 10,000 to 1 in 10,000 (a reduction of 1 in 10,000). If individual WTP for this risk reduction is $1,000, then the WTP for an avoided statistical premature mortality amounts to $10 million ($1,000/0.0001 change in risk). Hence, this value is population-normalized, as it accounts for the size of the population and the percentage of that population experiencing the risk. The same type of calculation can produce values for statistical incidences of other health endpoints.

For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we instead use the cost of treating or mitigating the effect to economically value the health impact. For example, for the valuation of hospital admissions, we use the avoided medical costs as an estimate of the value of avoiding the health effects causing the admission. These cost-of-illness (COI) estimates generally (although not in every case) understate the true value of reductions in risk of a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect.

3.3.5 Benefits Analysis Data Inputs

In Figure 3-3Figure , we summarize the key data inputs to the health impact and economic valuation estimates, which were calculated using BenMAP-CE model version 1.5.1 (Sacks et al., 2020). In the sections below we summarize the data sources for each of these inputs, including demographic projections, incidence and prevalence rates, effect coefficients, and economic valuation.

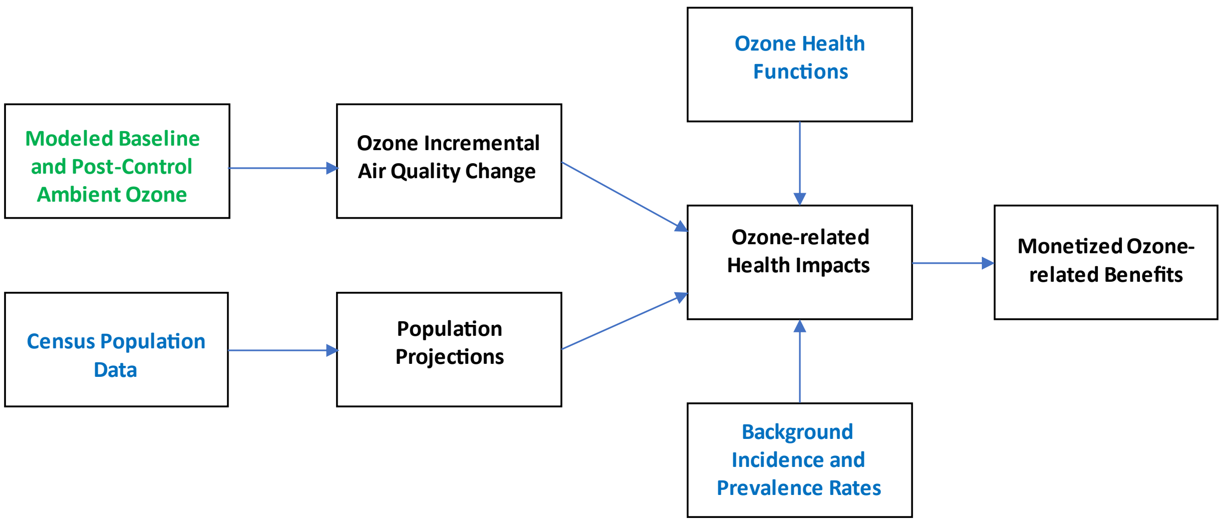

Figure 3-3 Data Inputs and Outputs for the BenMAP-CE Model

3.3.5.1 Demographic Data

Quantified and monetized human health impacts depend on the demographic characteristics of the population, including age, location, and income. We use projections based on economic forecasting models developed by Woods & Poole, Inc. (2015). The Woods & Poole database contains county-level projections of population by age, sex, and race to 2060, relative to a baseline using the 2010 Census data. Projections in each county are determined simultaneously with every other county in the U.S. to consider patterns of economic growth and migration. The sum of growth in county-level populations is constrained to equal a previously determined national population growth, based on Bureau of Census estimates (Hollmann et al., 2000). According to Woods & Poole, linking county-level growth projections together and constraining the projected population to a national-level total growth avoids potential errors introduced by forecasting each county independently (for example, the projected sum of county-level populations cannot exceed the national total). County projections are developed in a four-stage process:

- First, national-level variables such as income, employment, and populations are forecasted.

- Second, employment projections are made for 179 economic areas defined by the Bureau of Economic Analysis (U.S. BEA, 2004), using an "export-base" approach, which relies on linking industrial-sector production of non-locally consumed production items, such as outputs from mining, agriculture, and manufacturing with the national economy. The export-based approach requires estimation of demand equations or calculation of historical growth rates for output and employment by sector.
- Third, population is projected for each economic area based on net migration rates derived from employment opportunities and following a cohort-component method based on fertility and mortality in each area.
- Fourth, employment and population projections are repeated for counties, using the economic region totals as bounds. The age, sex, and race distributions for each region or county are determined by aging the population by single year by sex and race for each year through 2060 based on historical rates of mortality, fertility, and migration.

3.3.5.2 Baseline Incidence and Prevalence Estimates

Epidemiological studies of the association between pollution levels and adverse health effects generally provide a direct estimate of the relationship of air quality changes to the relative risk of a health effect, rather than estimating the absolute number of avoided cases. For example, a typical result might be that a 5 µg/m^3 decrease in daily $PM_{2.5}$ levels is associated with a decrease in hospital admissions of 3 percent. A baseline incidence rate, necessary to convert this relative change into a number of cases, is the estimate of the number of cases of the health effect per year in the assessment location, as it corresponds to baseline pollutant levels in that location. To derive the total baseline incidence per year, this rate must be multiplied by the corresponding population number. For example, if the baseline incidence rate is the number of cases per year per million people, that number must be multiplied by the millions of people in the total population.

The Health Benefits TSD (Table 12) summarizes the sources of baseline incidence rates and reports average incidence rates for the endpoints included in the analysis. For both baseline incidence and prevalence data, we used age-specific rates where available. We applied concentration-response functions to individual age groups and then summed over the relevant age range to provide an estimate of total population benefits. National-level incidence rates were used for most morbidity endpoints, whereas county-level data are available for premature mortality. Whenever possible, the national rates used are national averages, because these data are most applicable to a national assessment of benefits. For some studies, however, the only available incidence information comes from the studies themselves; in these cases, incidence in the study population is assumed to represent typical incidence at the national level.

We projected mortality rates such that future mortality rates are consistent with our projections of population growth (U.S. EPA, 2023b). To perform this calculation, we began first with an average of 2007-2016 cause-specific mortality rates. Using Census Bureau projected national-level annual mortality rates stratified by age range, we projected these mortality rates to 2060 in 5-year increments (U.S. Census Bureau). Further information regarding this procedure may be found in the Health Benefits TSD and the appendices to the BenMAP user manual (U.S. EPA, 2022a, 2023b).

The baseline incidence rates for hospital admissions and emergency department visits reflect the revised rates first applied in the Revised Cross-State Air Pollution Rule Update (U.S. EPA, 2021b). In addition, we revised the baseline incidence rates for acute myocardial infarction. These revised rates are more recent than the rates they replace and more accurately represent the rates at which populations of different ages, and in different locations, visit the hospital and emergency department for air pollution-related illnesses (AHRQ, 2016). Lastly, these rates reflect unscheduled hospital admissions only, which represents a conservative assumption that most air pollution-related visits are likely to be unscheduled. If air pollution-related hospital admissions are scheduled, this assumption would underestimate these benefits.

3.3.5.3 Effect Coefficients

Our approach for selecting and parametrizing effect coefficients for the benefits analysis is described fully in the Health Benefits TSD. Because of the substantial economic value associated with estimated counts of ozone-attributable deaths, we describe our rationale for selecting among long-term exposure epidemiologic studies below; a detailed description of all remaining endpoints may be found in the Health Benefits TSD. EPA selects hazard ratios from cohort studies to estimate counts of ozone-related premature death, following a systematic approach detailed in the Health Benefits TSD accompanying this RIA that is generally consistent with previous RIAs. Briefly, clinically significant epidemiologic studies of health endpoints for which ISAs report strong evidence are evaluated using established minimum and preferred criteria for identifying studies and hazard ratios best characterizing risk. Further discussion of the cohort studies and hazard ratios for quantifying ozone-attributable premature death can be found below in Section 3.3.6.

3.3.6 Quantifying Cases of Ozone-Attributable Premature Death

Mortality risk reductions account for the majority of monetized ozone-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. As noted above, the Health Benefits TSD describes fully the Agency's approach for quantifying the number and value of ozone-related impacts, including additional discussion of how the Agency selected the risk studies used to quantify ozone-related impacts in this RIA. The Health Benefits 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 (National Research Council, 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 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" (National Research Council, 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., 2005; Schwartz, 2005)In 2008, the National Academies of Science (National Research Council, 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 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" (National Research Council, 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., 2005; 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 & 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.S. EPA, 2020c). Beginning 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 and Schwartz (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 and Schwartz (2008) as June-August. Instead, we apply this risk estimate to our standard warm season of April-September.(Smith et al., 2009; Zanobetti & 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.S. EPA, 2020c). We currently use two estimates of ozone-attributable respiratory deaths from short-term exposures are estimated using the risk estimate parameters from Zanobetti and Schwartz (2008) and Katsouyanni et al. (2009). Ozone-attributable respiratory deaths from long-term exposures are estimated using Turner et al. (2016).

3.3.7 Characterizing Uncertainty in the Estimated Benefits

In any complex analysis using estimated parameters and inputs from numerous models, there are likely to be many sources of uncertainty. This analysis is no exception. The Health

Benefits TSD details our approach to characterizing uncertainty in both quantitative and qualitative terms. That Health Benefits TSD describes the sources of uncertainty associated with key input parameters including emissions inventories, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data for monetizing benefits, and assumptions regarding the future state of the country (i.e., regulations, technology, and human behavior). Each of these inputs is uncertain and affects the size and distribution of the estimated benefits. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits.

To characterize uncertainty and variability into this assessment, we incorporate three quantitative analyses described below and in greater detail within the Health Benefits TSD (Section 7.1):

1. A Monte Carlo assessment that accounts for random sampling error and between study variability in the epidemiological and economic valuation studies;

2. The quantification of ozone-related mortality using alternative ozone mortality effect estimates drawn from two epidemiologic studies; and

3. Presentation of 95th percentile confidence interval around each risk estimate.

Quantitative characterization of other sources of ozone uncertainties are discussed only in Section 7.1 of the Health Benefits TSD:

1. For adult all-cause mortality:

    a. The distributions of air quality concentrations experienced by the original cohort population (Health Benefits TSD Section 7.1.2.1);

    b. Methods of estimating and assigning exposures in epidemiologic studies (Health Benefits TSD Section 7.1.2.2);

    c. Confounding by ozone (Health Benefits TSD Section 7.1.2.3); and

    d. The statistical technique used to generate hazard ratios in the epidemiologic study (Health Benefits TSD Section 7.1.2.4).

2. Plausible alternative risk estimates for asthma onset in children (Health Benefits TSD Section 7.1.3), cardiovascular hospital admissions (Health Benefits TSD Section 7.1.4,), and respiratory hospital admissions (Health Benefits TSD Section 7.1.5);

Quantitative consideration of baseline incidence rates and economic valuation estimates are provided in Section 7.3 and 7.4 of the TSD, respectively. Qualitative discussions of various sources of uncertainty can be found in Section 7.5 of the TSD.

3.3.7.1 Monte Carlo Assessment

Similar to other recent RIAs, we used Monte Carlo methods for characterizing random sampling error associated with the concentration response functions from epidemiological studies and random effects modeling to characterize both sampling error and variability across the economic valuation functions. The Monte Carlo simulation in the BenMAP-CE software randomly samples from a distribution of incidence and valuation estimates to characterize the effects of uncertainty on output variables. Specifically, we used Monte Carlo methods to generate confidence intervals around the estimated health impact and monetized benefits. The reported standard errors in the epidemiological studies determined the distributions for individual effect estimates for endpoints estimated using a single study. For endpoints estimated using a pooled estimate of multiple studies, the confidence intervals reflect both the standard errors and the variance across studies. The confidence intervals around the monetized benefits incorporate the epidemiology standard errors as well as the distribution of the valuation function. These confidence intervals do not reflect other sources of uncertainty inherent within the estimates, such as baseline incidence rates, populations exposed, and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the benefits estimates.

3.3.7.2 Sources of Uncertainty Treated Qualitatively

Although we strive to incorporate as many quantitative assessments of uncertainty as possible, there are several aspects we are only able to address qualitatively. These attributes are summarized below and described more fully in the Health Benefits TSD.

Uncertainties are associated with the projection of emissions to analytic years. For most sectors, this process incorporates data from the base year and applying economic and other information to estimate changes in the activity for those sources in the intervening years, along with the application of any regulatory or economic drivers that would result in a changed rate of emissions per unit of activity in the analytic year. Uncertainties associated with applying air quality modeling to create ozone surfaces are discussed in U.S. EPA (2023a).

3.3.8 Estimated Number and Economic Value of Health Benefits

Table 3-6 through Table 3-9 report the estimated number of reduced premature deaths and illnesses in each year and regulatory alternative relative to the baseline along with the 95 percent confidence interval. The number of avoided estimated deaths and illnesses are calculated from the sum of individual reduced mortality and illness risk across the population. Table 3-10 reports the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95 percent confidence interval. We also report the stream of benefits from 2024 through 2038 for the final rule and the less- and more-stringent regulatory alternatives, using the monetized sums of long-term ozone mortality and morbidity impacts (Table 3-6 through Table 3-8).

When estimating the value of improved air quality over a multi-year time horizon, the analysis applies population growth and income growth projections for each future year through 2038 and estimates of baseline mortality incidence rates at five-year increments. Table 3-10 includes two estimates for each regulatory alternative and year. These estimates were quantified using two different epidemiological estimates for the mortality impact of ozone. One estimate reflects the impacts associated with short-term exposure on mortality impacts while the other reflects long-term exposure on mortality. These estimates should not be thought of as representing low and high bounds.

These tables include estimates based on discounting at two, three, and seven percent. Valuations based on three and seven percent discount rates are implemented as described in the TSD. We develop new valuations based on a two percent discount rate for effects which occur after the exposure. This applies to long-term mortality, asthma onset, and school loss days. For long-term mortality, we use the same lag structure for mortality as with three and seven percent, which results in a discount factor of 0.934, compared with 0.906 when discounting at three percent. For school loss days, we recalculate the valuation as previously done which yields a valuation of $1,186. For asthma onset, we are unable to calculate the valuation with a two percent discount rate and thus use the values based on a three percent rate as an approximation that is smaller in absolute value than it would be if discounted at two percent.

Table 3-6 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses in 2024 across Regulatory Options (95 percent confidence interval)[a]

		Less Stringent	Final Rule	More Stringent
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	2.8 (1.9 to 3.6)	2.8 (2.0 to 3.7)	2.8 (2.0 to 3.7)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	0.13 (0.051 to 0.20)	0.13 (0.052 to 0.20)	0.13 (0.052 to 0.20)
Morbidity effects				
Long-term exposure	Asthma onset[d]	23 (20 to 26)	23 (20 to 27)	23 (20 to 27)
	Allergic rhinitis symptoms[f]	130 (69 to 190)	130 (70 to 190)	130 (70 to 190)
Short-term exposure	Hospital admissions—respiratory[c]	0.31 (-0.082 to 0.70)	0.32 (-0.083 to 0.71)	0.32 (-0.083 to 0.71)
	ED visits—respiratory[e]	7.1 (2.0 to 15)	7.2 (2.0 to 15)	7.2 (2.0 to 15)
	Asthma symptoms	4,200 (-510 to 8,700)	4,200 (-520 to 8,800)	4,200 (-520 to 8,800)
	Minor restricted-activity days[c,e]	1,900 (770 to 3,000)	2,000 (780 to 3,100)	2,000 (780 to 3,100)
	School absence days	1,500 (-210 to 3,100)	1,500 (-210 to 3,200)	1,500 (-210 to 3,200)

[a] Values rounded to two significant figures.
[b] Applied risk estimate derived from April-September exposures to estimates of ozone across the April-September warm season.
[c] Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).
[d] Applied risk estimate derived from June-August exposures to estimates of ozone across the April-September warm season.
[e] Applied risk estimate derived from full year exposures to estimates of ozone across the April-September warm season.
[f] Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

Table 3-7 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses in 2027 across Regulatory Options (95 percent confidence interval)[a]

		Less Stringent	Final Rule	More Stringent
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	11 (7.4 to 14)	11 (7.5 to 14)	11 (7.5 to 14)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	0.48 (0.19 to 0.76)	0.49 (0.20 to 0.77)	0.49 (0.20 to 0.78)
Morbidity effects				
Long-term exposure	Asthma onset[d]	84 (72 to 95)	85 (73 to 97)	86 (73 to 97)
	Allergic rhinitis symptoms[f]	480 (250 to 700)	490 (260 to 710)	86 (73 to 97)
Short-term exposure	Hospital admissions—respiratory[c]	1.2 (-0.32 to 2.7)	1.2 (-0.32 to 2.7)	1.2 (-0.32 to 2.7)
	ED visits—respiratory[e]	26 (7.2 to 55)	27 (7.3 to 56)	27 (7.4 to 56)
	Asthma symptoms	15,000 (-1,900 to 32,000)	16,000 (-1,900 to 33,000)	16,000 (-1,900 to 33,000)
	Minor restricted-activity days[c,e]	6,900 (2,800 to 11,000)	7,000 (2,800 to 11,000)	7,100 (2,800 to 11,000)
	School absence days	5,500 (-770 to 11,000)	5,600 (-780 to 12,000)	5,600 (-780 to 12,000)

[a] Values rounded to two significant figures.
[b] Applied risk estimate derived from April-September exposures to estimates of ozone across the April-September warm season.
[c] Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).
[d] Applied risk estimate derived from June-August exposures to estimates of ozone across the April-September warm season.
[e] Applied risk estimate derived from full year exposures to estimates of ozone across the April-September warm season.
[f] Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

Table 3-8 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses in 2028 across Regulatory Options (95 percent confidence interval)[a]

		Less Stringent	Final Rule	More Stringent
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	49 (34 to 64)	56 (39 to 73)	57 (40 to 74)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	2.2 (0.90 to 3.5)	2.6 (1.0 to 4.0)	2.6 (1.0 to 4.1)
Morbidity effects				
Long-term exposure	Asthma onset[d]	400 (340 to 450)	450 (390 to 520)	460 (390 to 520)
	Allergic rhinitis symptoms[f]	2,300 (1,200 to 3,300)	2,600 (1,400 to 3,800)	2,600 (1,400 to 3,800)
Short-term exposure	Hospital admissions—respiratory[c]	5.9 (-1.6 to 13)	6.8 (-1.8 to 15)	6.9 (-1.8 to 15)
	ED visits—respiratory[e]	120 (34 to 260)	140 (39 to 300)	140 (40 to 300)
	Asthma symptoms	73,000 (-9,000 to 150,000)	84,000 (-10,000 to 170,000)	85,000 (-10,000 to 180,000)
	Minor restricted-activity days[c,e]	33,000 (13,000 to 52,000)	38,000 (15,000 to 59,000)	38,000 (15,000 to 60,000)
	School absence days	26,000 (-3,700 to 54,000)	30,000 (-4,200 to 62,000)	30,000 (-4,200 to 63,000)

[a] Values rounded to two significant figures.
[b] Applied risk estimate derived from April-September exposures to estimates of ozone across the April-September warm season.
[c] Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).
[d] Applied risk estimate derived from June-August exposures to estimates of ozone across the April-September warm season.
[e] Applied risk estimate derived from full year exposures to estimates of ozone across the April-September warm season.
[f] Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

Table 3-9 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses in 2038 across Regulatory Options (95 percent confidence interval)[a]

		Less Stringent	Final Rule	More Stringent
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	67 (46 to 87)	74 (51 to 95)	74 (51 to 96)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	3 (1.2 to 4.8)	3.3 (1.3 to 5.2)	3.3 (1.4 to 5.3)
Morbidity effects				
Long-term exposure	Asthma onset[d]	480 (410 to 540)	520 (450 to 590)	530 (450 to 600)
	Allergic rhinitis symptoms[f]	2,800 (1,500 to 4,100)	3,100 (1,600 to 4,400)	3,100 (1,600 to 4,500)
Short-term exposure	Hospital admissions—respiratory[c]	8.1 (-2.1 to 18)	8.9 (-2.3 to 20)	8.9 (-2.3 to 20)
	ED visits—respiratory[e]	160 (43 to 330)	170 (47 to 360)	170 (47 to 360)
	Asthma symptoms	88,000 (-11,000 to 180,000)	97,000 (-12,000 to 200,000)	97,000 (-12,000 to 200,000)
	Minor restricted-activity days[c,e]	40,000 (16,000 to 64,000)	44,000 (18,000 to 70,000)	44,000 (18,000 to 70,000)
	School absence days	32,000 (-4,500 to 67,000)	35,000 (-4,900 to 74,000)	35,000 (-5,000 to 74,000)

[a] Values rounded to two significant figures.

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

[c] Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).

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

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

[f] Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

Table 3-10 Estimated Discounted Economic Value of Avoided Ozone-Attributable Premature Mortality and Illness across Regulatory Options (95 percent confidence interval; millions of 2019 dollars)[a]

Disc. Rate	Year	Less Stringent			Final Rule			More Stringent		
2%	2024	$4.1 ($1.0–$8.5)	*and*	$32 ($3.6–$84)	$4.1 ($1.1–$8.6)	*and*	$33 ($3.6–$85)	$4.10 ($1.1–$8.7)	*and*	$33 ($3.6–$86)
	2027	$15 ($3.8–$32)	*and*	$120 ($14–$330)	$16 ($3.9–$33)	*and*	$130 ($14–$330)	$16 ($3.9–$33)	*and*	$130 ($14–$330)
	2028	$72 ($18–$150)	*and*	$580 ($64–$1,500)	$82 ($20–$170)	*and*	$660 ($73–$1,700)	$83 ($21–$180)	*and*	$670 ($74–$1,800)
	2038	$93 ($22–$200)	*and*	$820 ($87–$2,200)	$100 ($24–$220)	*and*	$900 ($96–$2,400)	$100 ($24–$220)	*and*	$900 ($97–$2,400)
3%	2024	$4.0 ($1–$8.5)[b]	*and*	$31 ($3.5–$82)[c]	$4.1 ($1.1–$8.6)[b]	*and*	$32 ($3.6–$83)[c]	$4.1 ($1.1–$8.6)[b]	*and*	$32 ($3.6–$83)[c]
	2027	$15 ($3.8–$32)[b]	*and*	$120 ($13–$320)[c]	$15 ($3.9–$33)[b]	*and*	$120 ($14–$320)[c]	$15 ($3.9–$33)[b]	*and*	$120 ($14–$320)[c]
	2028	$71 ($18–$150)[b]	*and*	$560 ($62–$1,500)[c]	$82 ($21–$170)[b]	*and*	$640 ($71–$1,700)[c]	$83 ($21–$170)[b]	*and*	$650 ($72–$1,700)[c]
	2038	$92 ($22–$200)[b]	*and*	$790 ($86–$2,100)[c]	$100 ($24–$220)[b]	*and*	$870 ($94–$2,300)[c]	$100 ($24–$220)[b]	*and*	$880 ($94–$2,300)[c]
7%	2024	$3.6 ($0.67–$8.0)[b]	*and*	$28 ($2.9–$74)[c]	$3.7 ($0.68–$8.1)[b]	*and*	$28 ($2.9–$75)[c]	$3.7 ($0.68–$8.1)[b]	*and*	$28 ($2.9–$75)[c]
	2027	$14 ($2.5–$30)[b]	*and*	$110 ($11–$290)[c]	$14 ($2.5–$31)[b]	*and*	$110 ($11–$290)[c]	$14 ($2.5–$31)[b]	*and*	$110 ($11–$290)[c]
	2028	$64 ($12–$140)[b]	*and*	$500 ($51–$1,300)[c]	$73 ($13–$160)[b]	*and*	$580 ($59–$1,500)[c]	$74 ($13–$160)[b]	*and*	$580 ($59–$1,500)[c]
	2038	$83 ($14–$190)[b]	*and*	$710 ($71–$1,900)[c]	$91 ($16–$210)[b]	*and*	$780 ($78–$2,100)[c]	$92 ($16–$210)[b]	*and*	$790 ($79–$2,100)[c]

[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] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate.
[c] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate.

Table 3-6 Stream of Human Health Benefits from 2024 through 2038: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Illness across Regulatory Options (discounted at 2 percent; millions of 2019 dollars)[a]

Year[b]	Less Stringent	Final Rule	More Stringent
2024	$30	$31	$31
2025	$30	$31	$31
2026	$110	$110	$110
2027	$110	$110	$110
2028	$500	$580	$580
2029	$500	$580	$590
2030	$510	$580	$590
2031	$510	$580	$590
2032	$510	$590	$590
2033	$510	$590	$600
2034	$590	$640	$650
2035	$590	$640	$650
2036	$590	$640	$650
2037	$590	$640	$650
2038	$580	$640	$640
PV	$6,300	$7,000	$7,100
EAV	$490	$540	$550

[a] For simplicity of exposition, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 3-10. Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.

[b] Air quality models were run for 2024, 2027, 2028, and 2038. Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2016 study); and ozone-related morbidity effects.

Table 3-7 Stream of Human Health Benefits from 2024 through 2038: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Illness across Regulatory Options (discounted at 3 percent; millions of 2019 dollars)[a]

Year[b]	Less Stringent	Final Rule	More Stringent
2024	$29	$30	$30
2025	$29	$30	$30
2026	$100	$110	$110
2027	$100	$110	$110
2028	$470	$540	$540
2029	$470	$540	$540
2030	$460	$530	$540
2031	$460	$530	$530
2032	$460	$530	$530
2033	$460	$520	$530
2034	$520	$570	$570
2035	$510	$560	$570
2036	$510	$560	$560
2037	$500	$550	$550
2038	$490	$540	$550
PV	$5,600	$6,200	$6,300
EAV	$470	$520	$530

[a] For simplicity of exposition, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 3-10. Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.
[b] Air quality models were run for 2024, 2027, 2028, and 2038. Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2016 study); and ozone-related morbidity effects.

Table 3-8 Stream of Human Health Benefits from 2024 through 2038: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Illness across Regulatory Options (discounted at 7 percent; millions of 2019 dollars)[a]

Year[b]	Less Stringent	Final Rule	More Stringent
2024	$26	$27	$27
2025	$25	$26	$26
2026	$86	$88	$88
2027	$83	$84	$84
2028	$360	$410	$420
2029	$340	$400	$400
2030	$330	$380	$380
2031	$310	$360	$360
2032	$300	$350	$350
2033	$290	$330	$340
2034	$310	$350	$350
2035	$300	$330	$330
2036	$290	$310	$320
2037	$270	$300	$300
2038	$260	$280	$290
PV	$3,600	$4,000	$4,100
EAV	$390	$440	$450

[a] For simplicity of exposition, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 3-10. Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.
[b] Air quality models were run for 2024, 2027, 2028, and 2038. Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2016 study); and ozone-related morbidity effects.

3.4 Ozone Vegetation Effects

Human exposure to ambient ozone concentrations is associated with adverse health effects, including premature respiratory mortality and cases of respiratory morbidity (U.S. EPA, 2020a). Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical, and epidemiological studies (U.S. EPA, 2020a). When adequate data and resources are available, the EPA has generally quantified several health effects associated with exposure to ozone (U.S. EPA, 2010, 2011e, U.S. EPA, 2021c). These health effects include respiratory morbidity, such as asthma attacks, hospital and emergency department visits, lost school days, and premature respiratory mortality. The scientific literature is also suggestive that exposure to ozone is associated with chronic respiratory damage and premature aging of the lungs.

3.5 Ozone Climate Effects

Ozone is a well-known short-lived climate forcing GHG (U.S. EPA, 2013). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2020c, 2023b). The IPCC AR5 estimated that the contribution to current warming levels of increased tropospheric ozone concentrations resulting from human methane, NO_X, and VOC emissions was 0.5 W/m^2, or about 30 percent as large a warming influence as elevated CO_2 concentrations. This quantifiable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles.

3.6 Ozone-Related Impacts Due to Methane

The tropospheric ozone produced by the reaction of methane in the atmosphere has harmful effects for human health and plant growth in addition to its climate effects (Nolte et al., 2018). In remote areas, methane is a dominant precursor to tropospheric ozone formation. Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane (Myhre et al., 2013). Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future (Myhre et al., 2013). Unlike NO_X and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's long atmospheric lifetime when compared to these other ozone precursors (Myhre et al., 2013). Reducing methane emissions, therefore, will contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects (USGCRP, 2018). The benefits of such reductions are global and occur in both urban and rural areas. As noted above, these effects are not currently included in estimates of the social cost of methane. However, a recent analysis by McDuffie et al. (2023) used a combination of global model simulations from the United Nations Environment Programme & Climate and Clean Air Coalition (UNEP/CCAC), in combination with BenMAP, to evaluate the additional risk in respiratory-related human mortality from ozone produced per ton of methane emissions. This approach is similar to the social cost of methane and finds that the monetized increase in respiratory-related human mortality risk from ozone produced from methane emissions in 2020 is $1,800 per ton of methane (95 percent confidence interval: $760–2,800 per mt CH_4 in 2020 US dollars). As discussed in U.S. EPA (2023f), this monetized result is similar to an earlier study by Sarofim et al. (2017) but smaller than a 2021 study conducted by the UNEP/CCAC, which included additional cardiovascular mortality risk due to elevated ozone concentrations (United Nations Environment Programme and Climate and Clean Air Coalition, 2021). Collectively, these and other prior studies suggest that there are additional risks to human health from the methane-ozone mechanism that are not currently accounted for in the social cost of methane. Applying the ozone-related health benefit per ton estimates from McDuffie et al. (2023) would yield a present value of the ozone-related health benefits from the 2024–2038 CH_4 emission reductions of the final rule on the order of $110 billion (2019 dollars), of which approximately $14 billion are accruing to populations within U.S. borders.[98] Because these benefits are the result of methane, which is a global pollutant, EPA believes it is most appropriate to focus attention on the global benefits to human health from the methane-ozone mechanism for the same reasons discuss above with respect to climate benefits. EPA will continue to look for opportunities to incorporate the ozone related impacts of CH_4 emissions in future updates to the SC-CH_4.

3.7 $PM_{2.5}$-Related Impacts Due to VOC Emissions

This final rulemaking is expected to result in emissions reductions of VOC, which are a precursor to $PM_{2.5}$, thus decreasing human exposure to $PM_{2.5}$ and the incidence of $PM_{2.5}$-related health effects, although the magnitude of this effect has not been quantified at this time. Most VOC emitted are oxidized to CO_2 rather than to PM, but a portion of VOC emissions contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2019a). Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is

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[98] This estimate relies on benefit per ton numbers that use the socioeconomics from the RFF-SPs and the 2 percent near-term Ramsey discounting approach. See McDuffie, E. E., Sarofim, M. C., Raich, W., Jackson, M., Roman, H., Seltzer, K., . . . Fann, N. (2023). The Social Cost of Ozone-Related Mortality Impacts From Methane Emissions. *Earth's Future*, *11*(9), e2023EF003853. https://doi.org/https://doi.org/10.1029/2023EF003853 for more details.

often lower than the biogenic (natural) contribution (U.S. EPA, 2019a). The potential for an organic compound to partition into the particle phase is highly dependent on its volatility such that compounds with lower volatility are more prone to partition into the particle phase and form secondary organic aerosols (SOA) (Cappa & Wilson, 2012; Donahue et al., 2012; Jimenez et al., 2009).

Hydrocarbon emissions from oil and natural gas operations tend to be dominated by high volatility, low-carbon number compounds that are less likely to form SOA (Helmig et al., 2014; Koss et al., 2017; Pétron et al., 2012). Given that only a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions, and the relatively volatile nature of VOCs emitted from this sector, it is unlikely that the VOC emissions reductions projected to occur under this final rule would have a large contribution to ambient secondary organic carbon aerosols. Therefore, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Moreover, without modeling air quality changes, we are unable to determine how this rule might affect air quality in downwind $PM_{2.5}$ nonattainment areas. However, we note that in future regulatory impact analyses supporting other regulations, the EPA plans to account for the emissions impacts of the oil and natural gas NSPS OOOOb and EG OOOOc in the baseline for the analysis.

3.7.1 $PM_{2.5}$ Health Effects

Decreasing exposure to $PM_{2.5}$ is associated with significant human health benefits, including reductions in respiratory mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$ exposure with adverse health effects in numerous toxicological, clinical, and epidemiological studies (U.S. EPA, 2019a). These health effects include asthma development and aggravation, decreased lung function, and increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing (U.S. EPA, 2019a). These health effects result in hospital and ER visits, lost workdays, and restricted activity days. When adequate data and resources are available, the EPA has quantified the health effects associated with exposure to $PM_{2.5}$ (U.S. EPA, 2023b).

When the EPA quantifies $PM_{2.5}$-related benefits, the Agency assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2019a). Based on our review of the current body of scientific literature, the EPA estimates PM-related premature mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

3.7.2 $PM_{2.5}$ Welfare Effects

Suspended particles and gases degrade visibility by scattering and absorbing light. Decreasing secondary formation of $PM_{2.5}$ from VOC emissions could improve visibility throughout the U.S. Visibility impairment has a direct impact on 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. Previous analyses show that visibility benefits are a significant welfare benefit category (U.S. EPA, 2006, 2011a, 2011c, 2012a). However, without air quality modeling of $PM_{2.5}$ impacts, we are unable to estimate visibility related benefits.

Separately, persistent and bioaccumulative HAP reported as emissions from oil and natural gas operations, including polycyclic organic matter, could lead to PM welfare effects. Several significant ecological effects are associated with the deposition of organic particles, including persistent organic pollutants and polycyclic aromatic hydrocarbons (PAHs) (U.S. EPA, 2009). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. (U.S. EPA, 2012b).

3.8 Hazardous Air Pollutants (HAP) Impacts

Available emissions data show that several different HAP are emitted from oil and natural gas operations. The HAP emissions from the oil and natural gas sector in the 2017 National Emissions Inventory (NEI) emissions data are summarized in Table 3-9. The table includes either oil and natural gas nonpoint or oil and natural gas point emissions of at least 10 tons per year, in descending order of annual nonpoint emissions. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and natural gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011b).

Table 3-9 Top Annual HAP Emissions as Reported in 2017 NEI for Oil and Natural Gas Sources

Pollutant	Nonpoint Emissions (tons/year)	Point Emissions (tons/year)
Benzene	26,869	502
Xylenes (Mixed Isomers)	25,410	506
Formaldehyde	23,413	222
Toluene	18,054	823
Acetaldehyde	2,722	26
Hexane	2,675	886
Ethyl Benzene	2,021	113
Acrolein	1,602	18
Methanol	1,578	342
1,3-Butadiene	337	5.80E-01
2,2,4-Trimethylpentane	252	46
Naphthalene	104	1.10E+00
Propionaldehyde	102	0.00E+00
PAH/POM - Unspecified	68	2.50E-02
1,1,2-Trichloroethane	25	1.40E-03
Methylene Chloride	22	8.70E-02
1,1,2,2-Tetrachloroethane	14	1.90E-03
Ethylene Dibromide	13	1.90E-03
Methyl Tert-Butyl Ether	0	17.30

In the subsequent sections, we describe the health effects associated with the main HAP of concern from the oil and natural gas sector: benzene (Section 3.8.13.8.1), formaldehyde (Section 3.8.23.8.2), toluene (Section 3.8.33.8.3), carbonyl sulfide (Section 3.8.43.8.4), ethylbenzene (Section 3.8.53.8.5), mixed xylenes (Section 3.8.63.8.6), and n-hexane (Section 3.8.73.8.7), and other air toxics (Section 3.8.83.8.8). This final rule is projected to reduce 590,000 tons of HAP emissions over the 2024 through 2038 period.[99] With the data available, it was not possible to estimate the change in emissions of each individual HAP.

[99] The projected emissions reductions from the proposed NSPS and EG, including projections of HAP reductions, are based upon the unit-level model plant analysis supporting this rulemaking multiplied by counts of units that are potentially affected by this proposal. The model plants and counts are built from a different basis than the oil and natural gas sector emissions estimated in the NEI. Comparisons between the projected emissions reductions under this proposal and the NEI should be made with caution.

Monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we are providing a qualitative discussion of the health effects associated with HAP emitted from sources subject to control under the final NSPS OOOOb and EG OOOOc. The EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional aspects of HAP-related risk from the oil and natural gas sector, including the distribution of that risk. This is discussed further in the context of environment justice in Section 4.3.4.

3.8.1 Benzene

The EPA's Integrated Risk Information System (IRIS) database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice (IARC, 1982; Irons et al., 1992; U.S. EPA, 2003a). The EPA states that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen, and the U.S. Department of Health and Human Services has characterized benzene as a known human carcinogen (IARC, 1987; NTP, 2004). Several adverse noncancer health effects have been associated with chronic inhalation of benzene in humans including arrested development of blood cells, anemia, leukopenia, thrombocytopenia, and aplastic anemia. Respiratory effects have been reported in humans following acute exposure to benzene vapors, such as nasal irritation, mucous membrane irritation, dyspnea, and sore throat (ATSDR, 2007a).

3.8.2 Formaldehyde

In 1989, the EPA classified formaldehyde as a probable human carcinogen based on limited evidence of cancer in humans and sufficient evidence in animals (U.S. EPA, 1991b). Later the IARC (2006, 2012) classified formaldehyde as a human carcinogen based upon sufficient human evidence of nasopharyngeal cancer and strong evidence for leukemia. Similarly, in 2016, the National Toxicology Program (NTP) classified formaldehyde as known to be a human carcinogen based on sufficient evidence of cancer from studies in humans supporting data on mechanisms of carcinogenesis (NTP, 2016). Formaldehyde inhalation exposure causes a range of noncancer health effects including irritation of the nose, eyes, and throat in humans and animals. Repeated exposures cause respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia in humans. Airway inflammation, including eosinophil infiltration, has been observed in animals exposed to formaldehyde. In children, there is evidence that formaldehyde may increase the risk of asthma and chronic bronchitis (ATSDR, 1999; WHO, 2002).

3.8.3 Toluene[100]

Under the 2005 Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005a), there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

[100] All health effects language for this section came from U.S. EPA. (2005b). *Toluene; CASRN 108-88-3* [Chemical Assessment Summary](Integrated Risk Information System (IRIS), Issue. https://iris.epa.gov/ChemicalLanding/&substance_nmbr=118.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

3.8.4 Carbonyl Sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate the eyes and skin in humans.[101] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under the EPA's IRIS program for evidence of human carcinogenic potential (U.S. EPA, 1991a).

3.8.5 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral

[101] Hazardous Substances Data Bank (HSDB), online database. US National Library of Medicine, Toxicology Data Network, available online at https://pubchem.ncbi.nlm.nih.gov/. Carbonyl sulfide health effects summary available at https://pubchem.ncbi.nlm.nih.gov/compound/10039#section=Safety-and-Hazards. Accessed April 26, 2020.

cavities in male and female rats exposed to ethylbenzene via the oral route (Maltoni et al., 1997; Maltoni et al., 1985). The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the IARC (1982) and the NTP (1999). The NTP (1999) carried out a chronic inhalation bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. The NTP also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma i female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). The IARC classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies (IARC, 2000).

3.8.6 Mixed Xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects (U.S. EPA, 2003b). Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys (ATSDR, 2007b). Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination (ATSDR, 2007b). The EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

3.8.7 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes, and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005a), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.

3.8.8 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by this rule, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in the EPA's IRIS database.[102]

3.9 Secondary Air Emissions Impacts

The control techniques to meet the storage vessel-related standards are associated with several types of secondary emissions impacts, which may partially offset the direct benefits of this rule. Table 3-10Table 3-10 shows the estimated secondary emissions associated with combustion of emissions as a result of these requirements; this includes additional flaring expected to occur as a result of detecting inactive flares through OGI and repairing them. Relative to the direct emission reductions anticipated from this rule, the magnitude of these secondary air pollutant increases is small.

[102] The U.S. EPA Integrated Risk Information System (IRIS) database is available at https://www.epa.gov/iris.

Table 3-10 Increases in Secondary Air Pollutant Emissions, Vapor Combustion at Storage Vessels (short tons per year)

Year	THC	CO	NO_X	PM	CO_2
2024	250	650	120	5	510,000
2025	510	1,300	250	9	1,100,000
2026	770	2,000	370	14	1,600,000
2027	1,000	2,700	500	19	2,100,000
2028	3,100	8,300	1,500	57	6,500,000
2029	3,200	8,400	1,500	58	6,600,000
2030	3,300	8,700	1,600	60	6,800,000
2031	3,500	9,200	1,700	64	7,200,000
2032	3,600	9,600	1,800	67	7,600,000
2033	3,800	10,000	1,800	69	7,900,000
2034	3,800	10,000	1,800	70	7,900,000
2035	3,900	10,000	1,900	72	8,200,000
2036	4,100	11,000	2,000	74	8,500,000
2037	4,200	11,000	2,000	76	8,700,000
2038	4,300	11,000	2,100	78	8,900,000
Total	43,000	110,000	21,000	790	90,000,000

Note: Totals may not appear to add correctly due to rounding.

The CO_2 impacts inTable 3-10 are the emissions that are expected to occur from vapor combustion at affected storage vessels. However, because of the atmospheric chemistry associated with the natural gas emissions, most of the carbon in the VOCs and CH_4 emissions expected in the absence of combustion-related emissions controls would have eventually oxidized forming CO_2 in the atmosphere and led to approximately the same long-run CO_2 concentrations as with controls.[103] Therefore, most of the impact of these CO_2 contribution to atmospheric concentrations from the flaring of CH_4 and VOC versus future oxidization is not additional to the impacts that otherwise would have occurred through the oxidation process.

However, there is a shift in the timing of atmospheric CO_2 concentration changes under the policy case, in which case combustion controls lead to contemporaneous increases in CO_2 concentrations, compared to the baseline where the CO_2 concentration increase is delayed through the oxidation process. In the case of VOC, the oxidization time in the atmosphere is relatively short, on the order of hours to months, so from a climate perspective the difference between emitting the carbon immediately as CO_2 during combustion or as VOC is expected to be

[103] The social cost of methane (SC-CH_4) used previously in this chapter to monetize the benefits of the CH_4 emissions reductions does not include the impact of the carbon in CH_4 emissions after it oxidizes to CO_2.

negligible. In the case of CH_4, the oxidization time is on the order of a decade, so the timing of the contribution to atmospheric CO_2 concertation will differ between the baseline and policy case. Because the growth rate of the SC-CO_2 estimates is lower than their associated discount rates, the present value of the estimated impact of CO_2 produced in the future via oxidized methane from these fossil-based emissions may be less than the present value of the estimated impact of CO_2 released immediately from combusting emissions, which would imply a small disbenefit associated with the earlier release of CO_2 during combustion of the CH_4 emissions.

In the NSPS OOOOa rulemaking, the EPA solicited comment on the appropriateness of monetizing: (1) the impact of CO_2 emissions associated with combusting methane and VOC emissions from oil and natural gas sites; and (2) a new potential approach for approximating this value using the SC-CO_2. The illustrative analysis in the NSPS OOOOa RIA provided a method for evaluating the estimated emissions outcomes associated with destroying one metric ton of methane by combusting fossil-based emissions at oil and natural gas sites (flaring) and releasing the CO_2 emissions immediately versus releasing them in the future via the methane oxidation process.[104] The analysis demonstrated that the potential disbenefits of flaring (i.e., an earlier contribution of CO_2 emissions to atmospheric concentrations) are minor compared to the benefits of flaring (i.e., avoiding the release of and associated climate impacts from CH_4 emissions).

While recognizing the challenges and uncertainties related to estimation of these secondary emissions impacts for this final rulemaking, EPA has continued to examine this issue in the context of this RIA and includes an illustrative analysis using the methodology from the NSPS OOOOa final RIA. Specifically, for this illustrative analysis, EPA assumes the oxidization process of CH_4 to be consistent with the modeling that underlies the SC-CH_4 estimates presented in Section 3.2. The estimated disbenefits associated with destroying one metric ton of methane through combustion of emissions at oil and natural gas sites and releasing the CO_2 emissions in 2023 instead of being released in the future via the methane oxidation process are found to be small relative to the benefits of flaring. Specifically, the disbenefit is estimated to be about \$20 per metric ton CH_4 (based on average SC-CO_2 using the 2 percent near-term target discount rate) or about one percent of the SC-CH_4 estimate per metric ton for 2024 (\$1,950).[105] The analogous

[104] See Section 4.7 of U.S. EPA (2016).
[105] See Table A.5.1 in U.S. EPA (2023e).

estimate for 2038 is \$37 per metric ton CH_4 or about one percent of the SC-CH_4 estimates per metric ton for 2038 (\$3,105).[106]

It is important to note that there are challenges and uncertainties related to this illustrative method and estimates, which was developed to analyze secondary fossil-based emissions from combustion. For example, these dollar per ton CH_4 estimates cannot readily be applied to the total CH_4 emissions reductions presented in Section 3.1 without additional information about the downstream outcomes associated with the recovered gas that is not flared — e.g., whether some of that captured gas going to be burned or leaked somewhere down the line. The EPA will continue to study this issue and assess the complexities involved in estimating the net emissions effects associated with secondary fossil-based emissions, including differences in the timing of contributions to atmospheric CO_2 concentrations. Given the uncertainties related to estimating net secondary emissions effects and that the EPA has not yet received appropriate input and review on some aspects of these calculations, the EPA is not including monetized estimates of the impacts of small changes in the timing of atmospheric CO_2 concentration increases in the benefits estimates in this RIA. The EPA will continue to follow the scientific literature on this topic and update its methodologies as warranted.

3.10 Total Benefits

Table 3-11 presents the PV and EAV of the projected climate benefits across the three regulatory options for the final NSPS OOOOb and EG OOOOc examined in this RIA. These

[106] To calculate the CO_2 related impacts associated the complete destruction of a ton of CH_4 emissions through flaring for this illustrative application, EPA took the difference between the SC-CO_2 at the time of the flaring and the discounted value of the CO_2 impacts assuming a geometric decay of CH_4 via the oxidation process with the same e-folding time and near-term target discount rate as used to estimate the SC-CO_2. See U.S. EPA. (2023f). *Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Washington, DC: U.S. EPA for discussion. This value was then scaled by 44/16 to account for the relative mass of carbon contained in a ton of CH_4 versus a ton of CO_2. More specifically, the impacts of shifting the CO_2 impacts are calculated as: $\left(\frac{44}{16}\right)\left[\text{SC-CO2}_\tau - \sum_{t=\tau}^{T} e^{-\frac{1}{l}(t-\tau)}\left(1-e^{-\frac{1}{l}}\right)\left(\frac{1}{1+r}\right)^{t-\tau}\text{SC-CO2}_t\right]$ where τ is the year the CH_4 is destroyed, l is the CH_4 e-folding time, r is the discount rate, and T is the time horizon of the analysis. Ideally the time horizon, T, would be sufficiently long to capture the period in which nearly all of the CH_4 is expected to have been oxidized. In this analysis we use the 2100 as the time horizon, making the assumption that the SC-CO_2 remains constant after 2080, the last year for which updated SC-GHG estimates are presented in ibid. This methodology improves upon the one presented at proposal by updating the oxidization process of CH_4 to be dynamic and consistent with the modeling that underlies the SC-CH_4 estimates.

values reflect an analytical time horizon of 2024 to 2038, are discounted to 2021, and presented in 2019 dollars. Multiple benefits estimates are presented reflecting alternative discount rates. The table includes consideration of the non-monetized benefits associated with the emissions reductions projected under this final rule.Table 3-12 Table 3-12 and Table 3-13, respectively,Table 3-13 present the same information for the final NSPS OOOOb and EG OOOOc separately.

Table 3-11 Comparison of PV and EAV of the Projected Benefits for the Final NSPS OOOOb and EG OOOOc across Regulatory Options, 2024–2038 (millions of 2019$)[a]

	2 Percent Near-Term Ramsey Discount Rate					
	PV	EAV	PV	EAV	PV	EAV
Climate Benefits[b]						
Less Stringent	$100,000	$7,800	$100,000	$7,800	$100,000	$7,800
Final Rule	$110,000	$8,500	$110,000	$8,500	$110,000	$8,500
More Stringent	$110,000	$8,500	$110,000	$8,500	$110,000	$8,500
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	PV	EAV	PV	EAV	PV	EAV
Ozone Health Benefits[c]						
Less Stringent	$6,200	$480	$5,400	$450	$3,100	$340
Final Rule	$7,000	$540	$6,100	$510	$3,500	$380
More Stringent	$7,000	$550	$6,100	$510	$3,500	$390
Total Monetized Benefits						
Less Stringent	$110,000	$7,800	$100,000	$7,800	$100,000	$7,800
Final Rule	$110,000	$8,500	$110,000	$8,500	$110,000	$8,500
More Stringent	$110,000	$8,500	$110,000	$8,500	$110,000	$8,500
Non-Monetized Benefits						
Benefits to provision of ecosystem services and ozone health benefits from reducing methane emissions by (in short tons):						
Less Stringent						54,000,000
Final Rule						58,000,000
More Stringent						59,000,000
Benefits to provision of ecosystem services from reducing VOC emissions by (in short tons)[b]:						
Less Stringent						14,000,000
Final Rule						16,000,000
More Stringent						16,000,000
$PM_{2.5}$-related health benefits from reducing VOC emissions by (in short tons)[b]:						
Less Stringent						14,000,000
Final Rule						16,000,000
More Stringent						16,000,000
Benefits to provision of ecosystem services and HAP-related health benefits from reducing HAP emissions by (in short tons):						
Less Stringent						540,000
Final Rule						590,000
More Stringent						590,000

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane ($SC\text{-}CH_4$) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the $SC\text{-}CH_4$ at the 2 percent near-term Ramsey discount rate. Please see Table 3.4 and 3.5 for the full range of monetized climate benefit estimates.

[c] The ozone-related health benefits estimates use the larger of the two benefits estimates presented in Table 3-10. Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.
[d] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 3.2 for a discussion of climate effects that are not yet reflected in the SC-CH_4 and thus remain unmonetized and Sections 3.4 through 3.8 for a discussion of other non-monetized benefits.

Table 3-12 Comparison of PV and EAV of the Projected Benefits for the Final NSPS OOOOb across Regulatory Options, 2023-2035 (millions of 2019$)[a]

	2 Percent Near-Term Ramsey Discount Rate					
	PV	EAV	PV	EAV	PV	EAV
Climate Benefits[b]						
Less Stringent	$43,000	$3,300	$43,000	$3,300	$43,000	$3,300
Final Rule	$44,000	$3,400	$44,000	$3,400	$44,000	$3,400
More Stringent	$44,000	$3,400	$44,000	$3,400	$44,000	$3,400
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Ozone Health Benefits[c]						
Less Stringent	N/A	N/A	N/A	N/A	N/A	N/A
Final Rule	N/A	N/A	N/A	N/A	N/A	N/A
More Stringent	N/A	N/A	N/A	N/A	N/A	N/A
Total Monetized Benefits						
Less Stringent	$43,000	$3,300	$43,000	$3,300	$43,000	$3,300
Final Rule	$44,000	$3,400	$44,000	$3,400	$44,000	$3,400
More Stringent	$44,000	$3,400	$44,000	$3,400	$44,000	$3,400
Non-Monetized Benefits						
Benefits to provision of ecosystem services and ozone health benefits from reducing methane emissions by (in short tons):						
Less Stringent						23,000,000
Final Rule						23,000,000
More Stringent						23,000,000
Benefits to provision of ecosystem services from reducing VOC emissions by (in short tons)[b]:						
Less Stringent						6,900,000
Final Rule						7,100,000
More Stringent						7,100,000
$PM_{2.5}$-related health benefits from reducing VOC emissions by (in short tons)[b]:						
Less Stringent						6,900,000
Final Rule						7,100,000
More Stringent						7,100,000
Benefits to provision of ecosystem services and HAP-related health benefits from reducing HAP emissions by (in short tons):						
Less Stringent						260,000
Final Rule						270,000
More Stringent						270,000

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate. Please see Table 3.4 and 3.5 for the full range of monetized climate benefit estimates.

[c] The ozone-related health benefits estimates use the larger of the two benefits estimates presented in Table 3-10. Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.
[d] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 3.2 for a discussion of climate effects that are not yet reflected in the SC-CH_4 and thus remain unmonetized and Sections 3.4 through 3.8 for a discussion of other non-monetized benefits.

Table 3-13 Comparison of PV and EAV of the Projected Benefits for the Final EG OOOOc Across Regulatory Options, 2024-2038 (millions of 2019$)[a]

	2 Percent Near-Term Ramsey Discount Rate					
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Climate Benefits[b]						
Less Stringent	$57,000	$4,500	$57,000	$4,500	$57,000	$4,500
Final Rule	$65,000	$5,100	$65,000	$5,100	$65,000	$5,100
More Stringent	$66,000	$5,100	$66,000	$5,100	$66,000	$5,100
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Ozone Health Benefits[c]						
Less Stringent	N/A	N/A	N/A	N/A	N/A	N/A
Final Rule	N/A	N/A	N/A	N/A	N/A	N/A
More Stringent	N/A	N/A	N/A	N/A	N/A	N/A
Total Monetized Benefits						
Less Stringent	$57,000	$4,500	$57,000	$4,500	$57,000	$4,500
Final Rule	$65,000	$5,100	$65,000	$5,100	$65,000	$5,100
More Stringent	$66,000	$5,100	$66,000	$5,100	$66,000	$5,100
Non-Monetized Benefits						
Benefits to provision of ecosystem services and ozone health benefits from reducing methane emissions by (in short tons):						
Less Stringent						31,000,000
Final Rule						35,000,000
More Stringent						35,000,000
Benefits to provision of ecosystem services from reducing VOC emissions by (in short tons)[b]:						
Less Stringent						7,500,000
Final Rule						8,600,000
More Stringent						8,700,000
$PM_{2.5}$-related health benefits from reducing VOC emissions by (in short tons)[b]:						
Less Stringent						7,500,000
Final Rule						8,600,000
More Stringent						8,700,000
Benefits to provision of ecosystem services and HAP-related health benefits from reducing HAP emissions by (in short tons):						
Less Stringent						280,000
Final Rule						320,000
More Stringent						330,000

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane ($SC\text{-}CH_4$) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the $SC\text{-}CH_4$ at the 2 percent near-term Ramsey discount rate. Please see Table 3.4 and 3.5 for the full range of monetized climate benefit estimates.

[c] The ozone-related health benefits estimates use the larger of the two benefits estimates presented in Table 3-10. Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.
[d] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 3.2 for a discussion of climate effects that are not yet reflected in the SC-CH_4 and thus remain unmonetized and Sections 3.4 through 3.8 for a discussion of other non-monetized benefits.

3.11 References

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4 ECONOMIC IMPACT AND DISTRIBUTIONAL ANALYSIS

The final NSPS OOOOb and EG OOOOc constitute an economically significant action under E.O. 12866. As discussed in previous section, the emissions reductions projected under the rule are likely to produce substantial climate benefits and ozone-related health benefits as well as non-monetized benefits from large reductions in emissions of multiple pollutants. At the same time, the NSPS OOOOb and EG OOOOc is projected to result in substantial environmental control expenditures by the oil and natural gas industry to comply with the rule.

While the national-level impacts demonstrate the final rule is likely to lead to significant benefits and costs, the benefit-cost analysis does not speak directly to potential economic and distributional impacts of the rule, which may be important consequences of the action. This section includes five sets of economic impact and distributional analyses directed toward complementing the benefit-cost analysis and includes an analysis of potential national-level impacts on oil and natural gas markets, a financial analysis of marginal oil and natural gas wells, a series of environmental justice analyses, employment impacts, and a Final Regulatory Flexibility Analysis (FRFA) that includes an analysis of projected compliance costs of the final NSPS OOOOb on small entities.

4.1 Oil and Natural Gas Market Impact Analysis

In addition to the engineering cost analysis that produces the compliance cost and emissions reduction projections that inform the net benefits analysis, the EPA developed a pair of single-market, static partial-equilibrium analyses of national crude oil and natural gas markets. The market impact analyses are intended to provide readers some information on the economic impacts of the final NSPS OOOOb and EG OOOOc and to inform the EPA's response to EO 13211 "Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use." The partial equilibrium market impact estimates, however, do not inform the projected engineering costs and emissions reductions used in the comparison of benefits and costs.

Our partial equilibrium analyses treat crude oil markets and natural gas markets separately. We implement a pair of single-market analyses instead of a coupled market or general equilibrium approach to provide broad insights into potential national-level market impacts while providing analytical transparency.

The oil market model assumes a single, aggregate U.S supplier, a single, aggregate world consumer, and a residual world supply. We assume the U.S. supply response to a percentage change in costs has the same effect as a percentage change in price. We do not try to model the residual world supply precisely. Instead, we model two extreme cases — perfectly inelastic residual world supply and perfectly elastic residual world supply. These cases bound the residual world supply response.

The natural gas market model assumes a single, aggregate U.S. supplier, a single, aggregate U.S. consumer, and no international trade. We assume the U.S. supply response to a percentage change in costs has the same effect as a percentage change in price. Existing natural gas markets are segmented in the short-term by transmission constraints, but prices are cointegrated across the United States. Infrastructure, including new infrastructure in the long term, joins disparate markets. The assumption of a single natural gas market is a long-term modeling assumption.

In each market, we first use a supply elasticity to solve for the supply change that results from the imposition of regulatory costs. Given the change in supply, we then use a demand elasticity to solve for the change in price that balances supply and demand. We use projected crude oil and natural gas prices and production for a select set of years of analysis to operationalize the model. In the sections that follow, we discuss the data and parameters used to implement the models, present results of each analysis, and conclude with a discussion of caveats and limitations of the analyses.

4.1.1 Crude Oil Market Model

The crude oil market model is a constant elasticity model that assumes a competitive U.S. market with a rest of world residual oil supply that is either perfectly inelastic or perfectly elastic. To find the changes in crude oil production and prices under the NSPS OOOOb and EG OOOOc, we first solve for the change in production using a supply elasticity and the regulatory cost. The year t change in U.S. oil production $\Delta Q_{O,t}^{US}$ is estimated using Eq. 4-1:

$$\Delta Q_{O,t}^{US} = \frac{C_{O,t}}{Q_{O,t}^{US} * P_{O,t}} * \varepsilon_{O,S} * Q_{O,t}^{US}, \qquad \text{Eq. 4-1}$$

where $C_{O,t}$ is the projected regulatory cost impacting oil-producing sources in year *t*, $Q_{O,t}^{US}$ is the baseline U.S. crude oil production in year *t*, $P_{O,t}$ is the baseline crude oil price, and $\varepsilon_{O,S}$ is the supply elasticity of crude oil. The term $\frac{C_{O,t}}{Q_{O,t}^{US} * P_{O,t}}$ describes the cost change as a fraction of revenue, akin to a percentage change in price. A key modeling assumption here is that, in addition to a constant elasticity, a fractional change in revenue due to a cost change is equivalent to a fractional change in output price. The term $\frac{C_{O,t}}{Q_{O,t}^{US} * P_{O,t}} * \varepsilon_{O,S}$ then describes the fractional change in production.

For the model assuming perfectly inelastic rest-of-world production, we use the change in supply solved in Eq. 4-1 the find the change in crude oil prices using Eq. 4-2:

$$\Delta P_{O,t} = \frac{\Delta Q_{O,t}^{US}}{Q_{O,t}^{World}} * \frac{1}{\varepsilon_{O,D}} * P_{O,t}, \qquad \text{Eq. 4-2}$$

where $Q_{O,t}^{World}$ is global production of crude oil and $\varepsilon_{O,D}$ is the world demand elasticity for crude oil.

Price does not change in the alternative model; it assumes perfectly elastic rest-of-world production, so $\Delta P_{O,t} = 0$.

4.1.2 Natural Gas Market Model

We model U.S. natural gas supply and demand as a closed market. For the natural gas market, we first find the change in quantity produced $\Delta \mathrm{Q}_{\mathrm{G,t}}$ using Eq 4.-3:

$$\Delta Q_{\mathrm{G,t}} = \frac{C_{G,t}}{Q_{G,t} * P_{G,t}} * \varepsilon_{G,S} * Q_{G,t}, \qquad \text{Eq. 4-3}$$

where $C_{G,t}$ is the projected regulatory cost impacting all segments of the natural gas industry in year *t*, $Q_{G,t}$ is the baseline U.S. production forecast, $P_{G,t}$ is the natural gas price forecast, and $\varepsilon_{G,S}$ is the supply elasticity for natural gas.

We then use the change in quantity solved in Eq. 4.3 to solve for the natural gas price change $\Delta P_{G,t}$ using Eq. 4-4:

$$\Delta P_{G,t} = \frac{\Delta \mathrm{Q}_{\mathrm{G,t}}}{Q_{G,t}} * \frac{1}{\varepsilon_{G,D}} * P_{G,t} \qquad \text{Eq. 4-4}$$

4.1.3 Assumptions, Data, and Parameters Used in the Oil and Natural Gas Market Models

This section presents the basics assumptions applied in this analysis. The section also presents the data and parameters used to operationalize the model, including our choice of years of analysis, elasticity estimates, and production and price data.

4.1.3.1 Years of Analysis

We estimate the price and quantity impacts of the final NSPS OOOOb and EG OOOOc on crude oil and natural gas markets for a subset of years within the time horizon analyzed in this RIA. We analyze 2024 and 2027 as these years represent the first and last year the requirements in the final NSPS OOOOb will be in effect for the purposes of the RIA before the requirements of EG OOOOc are assumed to go into effect. We then analyze market impacts in 2028, 2033, and 2038 to examine the effects of the EG OOOOc in addition to the cumulative impacts of the NSPS OOOOb. We analyze 2033 and 2038 to project impacts in later years of the time horizon.

4.1.3.2 Elasticity Choices

The elasticity estimates used in the analysis are based on estimates from the published economics literature (). Natural gas demand elasticity is calculated as the sector-level consumption-weighted average of demand elasticities from Hausman and Kellogg (2015). The consumption proportions used to weight the elasticities are derived from 2019 levels of natural consumption by the residential, commercial, industrial, and electric power sectors, as reported in EIA.

Table 4-1 Parameters Used in Market Analysis

Parameter	Symbol	Value	Source
Oil supply elasticity	$\varepsilon_{O,S}$	1.2	Newell , R. G., & B. C. Prest. 2019. The unconventional oil supply boom: Aggregate price response from microdata. *The Energy Journal* 40(3).
Oil demand elasticity	$\varepsilon_{O,D}$	-0.37	Coglianese , J., L. W. Davis, L. Kilian, & J. H. Stock. 2017. Anticipation, tax avoidance, and the price elasticity of gasoline demand. *Journal of Applied Econometrics* 32(1):1-15.
Natural gas supply elasticity	$\varepsilon_{G,S}$	0.9	Newel l, R. G., B. C. Prest, & A. B. Vissing. 2019. Trophy hunting versus manufacturing energy: The price responsiveness of shale gas." *Journal of the Association of Environmental and Resource Economists* 6(2): 391-431.
Natural gas demand elasticity	$\varepsilon_{G,D}$	-0.43	Sector-level consumption-weighted average of demand elasticities from Hausman, C. & R. Kellogg. 2015. Welfare and Distributional Implications of Shale Gas. *Brookings Papers on Economic Activity*:71-125.

4.1.3.3 Production and Price Data

Baseline U.S. crude oil production, dry gas production, West Texas Intermediate (WTI) crude oil prices, and Henry Hub natural gas prices are drawn from AEO2022. Prices are deflated to 2019 dollars using the GDP-Implicit Price Deflator. As the NSPS OOOOb and EG OOOOc apply to onshore production but not offshore production, only onshore U.S. crude oil production is analyzed. Dry natural gas production is the sum of onshore production from the lower 48 states and all production from Alaska. Baseline world crude oil production is from the Energy Information Administration's 2021 International Energy Outlook. presents the baseline crude oil and natural gas production and prices used in the market impacts analysis.

Table 4-2 Baseline Crude Oil and Natural Gas Production and Prices Used in Market Analysis

Data	Resource	Unit	Year 2024	2027	2028	2033	2038
Baseline Production[a]							
	U.S. Crude Oil Production	million bbl/day	10.6	11.1	11.1	10.9	10.8
	World Oil Production	million bbl/day	82.8	84.5	85.0	87.8	91.1
	U.S. Onshore Production	tcf/year	35.6	35.8	36.2	37.2	37.8
Baseline Prices[a]							
	Crude Oil	2019$/bbl	60.7	64.4	65.7	71.0	75.0
	Natural Gas	2019$/MMbtu	3.01	2.92	3.08	3.46	3.50
	Natural Gas	2019$/Mcf	3.12	3.03	3.19	3.59	3.62

[a] Baseline U.S. crude oil and natural gas production and prices drawn from AEO2022. Baseline world oil production drawn from EIA's International Energy Outlook.

4.1.3.4 Regulatory Cost Impacts

As discussed earlier, we assume the projected regulatory costs associated with the final NSPS OOOOb and EG OOOOc produce a fractional change in output price. We distribute the projected regulatory costs to crude oil markets and natural gas markets according to whether the emissions sources incurring the regulatory costs are more likely to be producing crude oil or producing, processing, or transporting natural gas. To begin, all projected regulatory costs for natural gas processing, storage, and transmission sources are assumed to impact the natural gas market. Within the production segment, projected regulatory costs for natural gas-related model plants are directed to natural gas markets and costs for oil-related model plants are assigned to crude oil markets. For example, projected regulatory costs associated with fugitive emissions monitoring at natural gas well sites are directed to the natural gas market, and projected regulatory costs at oil well sites are directed to crude oil markets.

For this analysis, we use the projected regulatory costs with capital costs annualized using a 7 percent interest rate. We also use the net regulatory costs, which include projected revenues from natural gas recovery from emissions abatement activities. Table 4-3 presents the results of decomposing the projected regulatory costs into crude oil and natural gas shares.

Table 4-3 Projected Regulatory Costs for the Final NSPS OOOOb and EG OOOOc Applied in the Market Analysis (millions 2019$)

	Year				
Resource	**2024**	**2027**	**2028**	**2033**	**2038**
Crude Oil	-10.8	238.0	1,531.6	1,952.1	2,569.8
Natural Gas	14.2	61.9	967.3	806.9	637.8

4.1.4 Results

The results of incorporating the projected regulatory costs into the crude oil market model are presented in . At its peak, the reduction is about 41.4 million barrels in 2038 or about 1.05 percent of crude oil production.

Table 4-4 Estimated Crude Oil Production and Prices Changes under the Final NSPS OOOOb and EG OOOOc

Variable	Change	Year 2024	2027	2028	2033	2038
U.S. Production	million bbls/year	0.2	-4.4	-28.0	-33.0	-41.1
	%	0.01%	-0.11%	-0.69%	-0.83%	-1.05%
U.S. Prices						
Assuming Perfectly Inelastic Rest of World Supply	$/bbl	0.00	0.03	0.16	0.20	0.25
	%	0.00%	0.04%	0.24%	0.28%	0.33%
Assuming Perfectly Elastic Rest of World Supply	$/bbl	0.0	0.0	0.0	0.0	0.0
	%	0.00%	0.00%	0.00%	0.00%	0.00%

We describe two models of world oil markets that bound the market price responses. The results of incorporating the projected regulatory costs into the crude oil market model are presented in . At its peak, the reduction is about 41.4 million barrels in 2038 or about 1.05 percent of crude oil production.

Table 4-4 describes results. Assuming perfectly inelastic world oil markets represents an upper bound on the crude oil price change. The maximum projected oil price change in modeled years is 0.25 dollars per barrel in 2038, an increase of 0.33 percent. The alternative model is that world oil markets are perfectly elastic and maintain a fixed oil price. In that case the price change would be zero. Table 4-5

presents results of entering the projected regulatory costs in the natural gas market model. We project a maximum natural gas price increase of about $0.06 per mcf and a maximum production reduction of about 272.5 million Mcf per year, changes of about 1.76 percent and 0.75 percent, respectively.

Table 4-5 Estimated Natural Gas Production and Prices Changes under the Final NSPS OOOOb and EG OOOOc

Variable	Change	Year 2024	2027	2028	2033	2038
U.S. Onshore Production	million Mcf/year	-4.1	-18.4	-272.5	-202.4	-158.3
	%	-0.01%	-0.05%	-0.75%	-0.54%	-0.42%
U.S. Prices						
	2019$/Mcf	0.00	0.00	0.06	0.05	0.04
	%	0.03%	0.12%	1.76%	1.27%	0.98%

We use the results in The results of incorporating the projected regulatory costs into the crude oil market model are presented in . At its peak, the reduction is about 41.4 million barrels in 2038 or about 1.05 percent of crude oil production.

Table 4-4The results of incorporating the projected regulatory costs into the crude oil market model are presented in . At its peak, the reduction is about 41.4 million barrels in 2038 or about 1.05 percent of crude oil production.

Table 4-4 and Table 4-5Table 4-5 to evaluate whether the final NSPS OOOOb and EG OOOOc is likely to have a significant effect on the supply, distribution, or use of energy as defined by EO 13211. To make this determination, we compare the projected change in crude oil and natural gas production to guidance articulated in a January 13, 2021, OMB memorandum "Furthering Compliance with Executive Order 13211, Titled "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.[107] With respect to crude oil production, the guidance indicates that a regulatory action produces a significant adverse effect if it is expected to produce reductions in crude oil supply in excess of 20 million barrels per year. With respect to natural gas production, the guidance indicates that a regulatory action produces a significant adverse effect if it reduces natural gas production in excess of 40 million mcf per year.[108] The maximum projected annual decreases in both oil production and natural gas production exceed benchmarks for adverse effects, so this analysis indicates the final NSPS OOOOb and EG OOOOc constitutes a significant energy action.

4.1.5 Caveats and Limitations of the Market Analysis

The oil and natural gas market impact analysis presented in this section is subject to several caveats and limitations, which we discuss here. As with any modeling exercise, the market impact analysis presented here depends crucially on uncertain input parameters. These

[107] See https://www.whitehouse.gov/wp-content/uploads/2021/01/M-21-12.pdf.

[108] The 2021 E.O. 13211 guidance memo states that the natural gas production decrease that indicates the regulatory action is a significant energy action is 40 mcf per year. Because this is a relatively small amount of natural gas and previous guidance from 2001 indicated a threshold of 25 million Mcf, we assume the 2021 memo was intended to establish 40 million Mcf as the indicator of an adverse energy effect. See https://www.whitehouse.gov/wp-content/uploads/2017/11/2001-M-01-27-Guidance-for-Implementing-E.O.-13211.pdf

parameters include the cost to firms of compliance, the amount of natural gas that would be recovered and sold because of emissions abatement requirements compliance, baseline projections, and elasticity estimates. We note the change in price is particularly sensitive to the demand elasticity.

This analysis considers two residual rest-of-world supply models — perfectly elastic and perfectly inelastic. The structure of international oil markets (both supply and demand) have shifted historically and may shift in the future. While these models bound the minimum and maximum price changes, there is uncertainty within those bounds. One common modeling assumption is that world oil prices are fixed relative to policy changes. This would imply perfectly elastic residual rest-of-world supply.

This analysis uses a single-period model which is parameterized for different years, whereas dynamic effects are important in oil and natural gas markets. Production decisions relating to drilling and shutting-in wells affect future production, well decline curves, and intertemporal price arbitrage (the Hotelling Rule) (Hotelling, 1931). Consideration of dynamic effects may shift numerical results. To the extent the NSPS OOOOb and EG OOOOc may impact well drilling and shut-in decisions, the static analysis present here potentially overlooks important distributional consequences of the final regulation.

This analysis does not distinguish between different regions of the United States. The cost of producing oil and natural gas varies over the United States. Compliance costs may also vary. Reductions in oil and natural gas production would be larger in regions with higher production costs or higher compliance costs. This could result in different price changes in different regions of the country if oil is there are bottlenecks in oil or natural gas shipping infrastructure.

Oil and natural gas markets are linked on both the supply and demand sides. On the supply side, individual wells generally produce a mixture of oil and natural gas, and some of the same resources can be used to drill either oil-targeting wells or natural gas-targeting wells. On the demand side, oil and natural gas are substitutes in some markets. Consideration of these linkages may additionally shift numerical results.

4.2 Financial Analysis of Marginal Wells

In addition to the oil and natural gas market impact analysis the EPA developed a financial analysis of marginal oil and natural gas wells. The marginal well analysis is intended to provide readers some information on the financial condition of marginal well owners and operators. The financial analysis, however, does not inform the projected engineering costs and emissions impacts used in the comparison of benefits and costs.

Marginal oil and gas wells are important to consider for several reasons. First, marginal wells are the most numerous type of existing well by production level, comprising more than 75% of existing oil and natural gas wells in the United States. Second, while EPA does not have data on the distribution of ownership based on firm size, there are small owners and operators who own marginal oil and natural gas wells. Third, commenters have brought up marginal wells in many contexts and these comments are illustrative of the importance of marginal oil and natural gas wells to the public. Finally, states are responsible for oil and gas wells that may be orphaned by owners within their boundaries. With the large numbers of marginal oil and gas wells across the country, the financial and pollution burdens on states may be significant if some owners and operators become insolvent and their marginal wells become the responsibility of the government.

The financial analysis assumes a baseline regulatory environment along with assumptions on operating and fixed costs and estimates profits or losses of marginal wells for a single year based on different oil and natural gas production levels. In the subsequent section, we examine the financial condition of marginal wells, discuss the data and parameters used to implement the analysis, present results of the analysis, and conclude with a discussion of caveats and limitations of the analysis. With the available data and the complexity described, we cannot estimate the impacts of the final regulation on the owners or operators of marginal wells.

4.2.1 Descriptive Statistics on Marginal Wells

According to the EIA, the total number of producing oil and gas wells in the United States in 2021 was 916,934, of which 403,294 were oil wells and 513,640 were natural gas wells.[109] The amount of oil or gas produced from each well varies from less than one barrel of oil equivalent per day (BOE) to over 12,800 BOE. This section focuses on marginal wells, that is, low-producing wells. EPA uses the EIA definition of a marginal oil well, which is one that over the course of a calendar year, produces 15 barrels per day or less. For gas wells, the equivalent production rate is 90,000 cubic feet per day or less.

Even though many wells are considered marginal, these wells represent a relatively small portion of total domestic production. In 2021, marginal wells comprised about 78 percent of all producing wells in the United States. There were 318,256 marginal oil wells, or 78 percent of oil wells, and 396,347 marginal natural gas wells, or 77 percent of natural gas wells. Marginal oil wells produced about 7 percent of the total oil production. Of these marginal oil wells, there were 299,368 wells, about 74 percent of the total oil wells, that produced 10 BOE per day or less. These oil wells accounted for about 5 percent of the total U.S. oil production. If marginal oil wells are further segmented, 157,916 wells, or 39 percent of total oil wells, produced less than one BOE per day, or about 0.46 percent of the total U.S oil production. Table 4-6 presents the numbers of oil wells and production information.

Table 4-6 Distribution of U.S Marginal Oil Wells in 2021

Production rate bracket (BOE/d)[a]	Number of Oil Wells	Share of Total Number of Oil Wells (%)	Production Amount (million barrels)	Share of Total Oil Production (%)
0–1	157,916	39	16.204	0.46
1–2	45,332	11	21.218	0.60
2–4	45,415	11	42.042	1.19
4–6	24,019	6	37.128	1.05
6–8	15,368	4	33.334	0.94
8–10	11,318	3	31.354	0.89
Subtotal <=10	299,368	74	181.280	5.14
10–12	8,735	2	29.204	0.83
12–15	10,153	3	41.235	1.17
Subtotal <=15	318,256	79	251.718	7.13
All Oil Wells	403,294	100	3528.769	100.00

Source: Energy Information Administration: The Distribution of U.S. Oil and Natural Gas Wells by Production Rate, December 2022. See link to Appendix B: Selected summary tables at https://www.eia.gov/petroleum/wells/.
[a] Production rate is defined as barrels of oil equivalent per day (BOE/d).

[109] See report available at https://www.eia.gov/petroleum/wells/. Data tables available in link to Appendix B: Selected summary tables.

Table 4-7 presents information on the number of natural gas wells and production for 2021. The patterns for natural gas wells are like those for oil wells. Marginal natural gas wells produced about 7.5 percent of the total natural gas production. There were 365,606 natural gas wells, about 71 percent of the total natural gas wells, that produced 10 BOE per day or less. These wells accounted for about 5 percent of the total U.S. natural gas production. Of those wells, 166,864 wells, or 39 percent of total natural gas wells, produced less than one BOE per day, or about 0.38 percent of the total U.S. natural gas production.

Table 4-7 Distribution of U.S Marginal Natural Gas Wells in 2021

Production rate bracket (BOE/d)[a]	Number of Natural Gas Wells	Share of Total Number of Natural Gas Wells (%)	Production Amount (million BOE)	Share of Total Natural Gas Production (%)
0–1	166,864	32	122	0.38
1–2	57,265	11	168	0.52
2–4	60,332	12	351	1.09
4–6	37,163	7	363	1.13
6–8	25,358	5	344	1.07
8–10	18,624	4	323	1.01
Subtotal <=10	365,606	71	1,671	5.21
10–12	14,382	3	304	0.95
12–15	16,359	3	424	1.32
Subtotal <=15	396,347	77	2,399	7.48
All Gas Wells	513,640	100	32,092	100.00

Source: Energy Information Administration: The Distribution of U.S. Oil and Natural Gas Wells by Production Rate, December 2022. See link to Appendix B: Selected summary tables at https://www.eia.gov/petroleum/wells/.
[a] Production rate is defined as barrels of oil equivalent per day (BOE/d).

While marginal wells account for a relatively small percentage of domestic production of oil and natural gas, recent studies suggest that their contribution to methane emissions from oil and natural gas production is much greater. For example, in a study funded by DOE's National Energy Technology Laboratory (DOE-NETL), Bowers (2022) estimates that marginal natural gas and oil wells account for 59 percent and 37 percent of cumulative methane emissions from oil and natural gas production, respectively, and roughly half of cumulative methane emissions from combined oil and natural gas production. Similarly, Omara et al. (2022) estimate that low production well sites account for roughly half (95 percent confidence interval: 37–75 percent) of all oil and natural gas well site methane emissions. In the analysis performed for this final rulemaking, we estimate that marginal wells account for 47–53 percent of well site methane emissions and 49–55 percent of reductions for the quantified emissions sources once the EG is assumed to take effect in 2028, with the ranges due to differing percentages from year to year.

4.2.2 Marginal Wells Financial Analysis Model

The expected single year profit is calculated for marginal wells in each production bracket reported by the EIA. A single year is calculated because oil and natural gas production from a particular well naturally declines over time. Assuming the single year is the first year of the remaining life of the well, it is very likely that this single year captures the maximum profit for the remaining production life of the average marginal well.

The parameter values presented in Table 4-8 are obtained from comments submitted for the November 2021 Proposal and the December 2022 Supplemental Proposal. The profit is estimated prior to any new regulation by any government entity. Natural gas wells primarily produce natural gas but there is also a relatively small amount of oil produced. Similarly, oil wells also produce some natural gas. The gross revenue is calculated by adding gas and oil production for marginal wells multiplied by their respective prices then subtracting the landowner royalty:

$$Gross\_Revenue \ = (1 - Royalty\_Rate) * (Oil\_Price * Oil\_Production + Gas\_Price * Gas\_Production), \qquad \text{Eq. 4-5}$$

here $Oil\_Production$ and $Gas\_Production$ are the respective annual production levels for each production bracket reported by the EIA. Total costs, which include operating costs and fixed costs, are subtracted from total revenue to obtain net profit:

$$Operating\_Cost = (Severance + Oil\_Transport + Variable\_O\&M) * Oil\_Production + (Gas\_Transport + Gas\_Treat + Gas\_Operating\ ) * Gas\_Production + Well\_Overhead * 12, \qquad \text{Eq. 4-6}$$

where $Severance, Oil\_Transport, Variable\_O\&M$ represent annual variable costs for oil production, $Gas\_Transport, Gas\_Treat, Gas\_Operating$ represent annual variable costs for gas production, and $Well\_Overhead * 12$ is the annual fixed costs. Profit is estimated using the follow equation:

$$Profit = Gross\_Revenue - Operating\_Cost \qquad \text{Eq. 4-7}$$

Table 4-8 Marginal Well Financial Analysis Parameters

Parameter	Description	Value
Royalty	Landowner royalty[a]	20%
Gas_Transport	Transportation cost ($/mcf)[a]	$ 0.30
Gas_Treat	Treating cost ($/mcf)[a]	$ 0.35
Gas_Operating	Operating and compression cost ($/mcf)[a]	$ 1.10
Well_Overhead	Fixed overhead ($/well/month)[a]	$ 250.00
Severance	Severance tax ($/bbl)[b]	$ 3.00
Oil_Transport	Transportation cost ($/bbl)[b]	$ 4.00
Variable_O&M	Variable operation and maintenance ($/bbl)[b]	$ 4.00

[a] Source Riverside comment on November 2021 Proposal (EPA-HQ-OAR-2021-0317-0411)
[b] Source Michigan Oil and Gas Association comments on December 2022 Proposal (EPA-HQ-OAR-2021-0317-2257).

As a point of comparison for the cost information provided by commenters, Weber et al. (2021) present a case study where they conduct a break-even analysis of marginal conventional natural gas wells in Pennsylvania. Based on publicly available data and company disclosures from Diversified Energy Company, the largest operator of conventional wells in Pennsylvania, the authors estimate the fixed costs and operating costs of natural gas wells in the company's conventional natural gas well portfolio. According to Weber et al. (2021), Diversified has more than 60,00 wells across Appalachia, with the largest concentrations in Pennsylvania and West Virginia. Weber et al. (2021) estimate operating costs to be about $886 annually and variable costs to be $0.74 per Mcf for the average natural gas well. Using these values, Weber et al. (2021) estimate that wells with a production rate below 0.5 Mcf per day were likely to be uneconomical, assuming a high natural gas price scenario of $3.94. The variable costs used in this analysis include the gas transport cost of $0.30 per Mcf, the gas treatment cost of $0.35 per mcf, and operating and compression cost of $1.10 per Mcf for a total of $1.75 per Mcf. The fixed costs are estimated at $3,000 per well annually. The costs are higher than reported in Weber et al. (2021), however, the authors note that Diversified has an economy of scale in Pennsylvania that likely reduces operating expenses below that incurred by other operators in the state and the regional nature of the study make it difficult to directly compare nationwide.

Weber et al. (2021) also find evidence that operators postpone plugging marginal conventional natural gas wells in Pennsylvania. They find that about one-third of wells considered uneconomical in 2019 have not been plugged, which include wells with zero production and wells producing below 0.5 Mcf per day. The authors also document that these wells have reported low- or zero-production over multiple years yet have remained unplugged over this time period. The authors also find that more than 37 percent of the wells that reported no production in 2019 also had no reported production from 2015 to 2018. For wells that produced below the 0.5 Mcf per day threshold, 32 percent were below the threshold for 2015 to 2019.

4.2.3 Results

The results of the financial analysis are presented in Table 4-9, Table 4-10, and Table 4-11. The tables present the profit estimation for the average monthly price of oil and natural gas from October 2022 to September 2023, as well as the low and high prices for the same period. In each table, the One Year Net Profit is the estimated profit for a single year from an average marginal well in 2021 before any additional regulatory costs are considered. In addition to presenting the estimated profits for all oil and gas wells with production of 15 barrels of oil equivalent per day (BOE) (listed in the last row of the table), the estimated profits are also disaggregated into smaller production brackets to give a fuller picture of the profits of marginal oil and gas wells. This highlights the feature that, while comprising a smaller percentage of the overall number of marginal wells, the higher producing marginal wells generate comparatively more profits thereby increasing the average profits of all marginal wells. This can be seen when comparing the estimated single year profit for average marginal oil and gas wells in Table 4-9, $42,033 and $5,648, respectively, to each disaggregated production bracket.

Focusing on the average price scenario in Table 4-9, marginal oil wells are profitable at every production level. At the lowest production bracket, 0–1 BOE, the average oil well earns an estimated positive profit of $2,968. At the next highest production level, 1–2 BOE, the profits for the average oil well are estimated to be $23,138. At the highest production level for marginal wells, 12-15 BOE, the profits are more than $221,000 per year.

Marginal gas wells can be unprofitable before the addition of any regulatory costs and have lower profits than marginal oil wells in corresponding production bands. Again, looking at the average price scenario in Table 4-9, the average gas wells in the 0–1 production bracket are estimated to be unprofitable with $2,075 loss. Estimated profits are positive for 1–2 BOE at $538 with the highest level of profits also occuring at the 12–15 BOE production band at over $36,444 per year.

As a sensitivity check on the average price scenario, low and high price scenarios are also presented. In Table 4-10 the one-year profits for the low oil and natural gas prices are presented. In the low-price scenario the oil price is assumed to be $70.25 per barrel and the natural gas price is assumed to be $2.15 per Mcf. Profits for marginal oil wells follow a similar pattern as the average price scenario, profitable in all production bands, with profits rising with production. For marginal natural gas wells, profits do not become positive until production reaches the 4–6 BOE per day range. While there are some production bands that have relatively high levels of profits, such as the 12-15 BOE per day band, average profits for all marginal gas wells are negative.

Table 4-11 contains the one-year profit estimates for the high price scenario. In the high-price scenario the oil price is assumed to be $89.43 per barrel and the natural gas price is assumed to be $5.66 per Mcf. While the one-year profits for marginal oil wells behave similarly to the average and the low-price scenarios, there is one notable result for marginal natural gas wells. One-year profits for the 0-1 BOE per day production band are negative. While not directly comparable to the regional study by Weber et al. (2021), this result is in general agreement with their conclusion that the lowest producing natural gas wells are likely to be uneconomical.

Compliance costs stemming from the requirements for each production site depend on the equipment located at the site. While data that correlates well site production levels and site equipment is scarce, our analysis of the 2016 ICR data suggests that low production sites generally have less equipment than non-low production sites (see, e.g., Table 2-16). When applied to our well site projections, we estimate that, depending on analysis year, roughly 50–60 percent of sites would be classified as wellhead only or small sites for the purposes of the fugitives monitoring requirements. These sites are subject to the least stringent standards, costing an estimated $336–660 per site per year, depending on whether the site require additional travel. In addition, we estimate that 45–50 percent of sites do not have pneumatic controllers. For those that do, we estimate that roughly 60 percent have two or fewer controllers. As an example, for existing sites with two controllers that do not have access to grid electricity, we estimate an annualized compliance cost of $1,312 for a retrofit with solar powered electric controllers, not including $630 in gas savings assuming both controllers are intermittent bleed with average emissions rates consistent with the assumptions in the Final Rule TSD.[110] See the December 2022 TSD and the Final Rule TSD for more information on the costs of controllers.

Table 4-9 Estimated Revenues, Costs, and Profits for Marginal Wells for 2021: Average Oil and Natural Gas Prices[a]

	Oil Wells			Gas Wells		
Production rate bracket (BOE/d)	**One Year Gross Revenue**	**Operating Cost**	**One Year Net Profit**	**One Year Gross Revenue**	**Operating Cost**	**One Year Net Profit**
0–1	$ 7,285	$ 4,317	$ 2,968	$ 2,350	$ 4,426	$ (2,075)
1–2	$ 31,938	$ 8,799	$ 23,138	$ 9,085	$ 8,547	$ 538
2–4	$ 62,593	$ 14,492	$ 48,101	$ 18,747	$ 14,138	$ 4,609
4–6	$ 105,157	$ 22,645	$ 82,512	$ 32,632	$ 21,948	$ 10,684
6–8	$ 147,241	$ 30,749	$116,491	$ 46,447	$ 29,664	$ 16,783
8–10	$ 188,432	$ 38,769	$149,663	$ 60,637	$ 37,427	$ 23,210
Subtotal <=10[b]	$ 42,367	$ 10,870	$ 31,497	$ 15,294	$ 11,933	$ 3,360
10–12	$ 229,093	$ 46,776	$182,317	$ 74,245	$ 45,130	$ 29,115
12–15	$ 278,452	$ 56,594	$221,858	$ 91,034	$ 54,589	$ 36,444
Subtotal <=15[c]	$ 55,424	$ 13,392	$ 42,033	$ 20,530	$ 14,882	$ 5,648

Note: One year of financial estimates for marginal oil and natural gas wells using the average monthly price of oil and natural gas. One Year Gross Revenue is estimated using Equation 4-5. Operating costs are fixed plus variable costs as calculated by Equation 4-6, using parameters from Table 4-8. One Year Net Profit is calculated from Equation 4-7.
[a] Source EIA. Average Monthly oil and natural gas prices from October 2022 to September 2023: Oil price is West Texas Intermediate, $78.73/bbl; See https://www.eia.gov/dnav/pet/hist/rwtcM.htm. Natural gas price is Henry Hub, $3.24/mcf; See https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.
[b] Subtotals are averages for oil and natural gas wells with the 10 BOE per day or less range.
[c] Subtotals are averages for all oil and natural gas wells with 15 BOE per day or less.

[110] Costs here are based on the ‘Two Electric Controllers Solar’ scenario illustrated on the ‘electric controllers’ tab from the pneumatic controllers spreadsheet accompanying the December 2022 TSD (EPA-HQ-OAR-2021-0317-1578_attachment_2.xlsx), applying a capital recovery factor based on a 7 percent interest rate and 15 year control lifetime to the estimated capital cost of $15,102 and adding it to an estimated reduction in maintenance costs of $346. Gas savings is calculated based on an assumed gas price of $3.24 per mcf.

Table 4-10 Estimated Revenues, Costs, and Profits for Marginal Wells for 2021: Low Oil and Natural Gas Prices[a]

	Oil Wells			Gas Wells		
Production rate bracket (BOE/d)	**One Year Gross Revenue**	**Operating Cost**	**One Year Net Profit**	**One Year Gross Revenue**	**Operating Cost**	**One Year Net Profit**
0–1	$ 6,480	$ 4,317	$ 2,163	$ 1,633	$ 4,426	$ (2,793)
1–2	$ 28,397	$ 8,799	$ 19,597	$ 6,297	$ 8,547	$ (2,250)
2–4	$ 55,595	$ 14,492	$ 41,103	$ 13,134	$ 14,138	$ (1,004)
4–6	$ 93,246	$ 22,645	$ 70,601	$ 23,063	$ 21,948	$ 1,115
6–8	$ 130,452	$ 30,749	$ 99,703	$ 32,967	$ 29,664	$ 3,302
8–10	$ 166,829	$ 38,769	$128,060	$ 43,213	$ 37,427	$ 5,787
Subtotal <=10[b]	$ 37,588	$ 10,870	$ 26,719	$ 10,785	$ 11,933	$ (1,149)
10–12	$ 202,697	$ 46,776	$155,921	$ 52,921	$ 45,130	$ 7,792
12–15	$ 246,192	$ 56,594	$189,598	$ 64,919	$ 54,589	$ 10,330
Subtotal <=15[c]	$ 49,129	$ 13,392	$ 35,737	$ 14,528	$ 14,882	$ (354)

Note: One year of financial estimates for marginal oil and natural gas wells using low oil and natural gas prices. One Year Gross Revenue is estimated using Equation 4-5. Operating costs are fixed plus variable costs as calculated by Equation 4-6, using parameters from Table 4-8. One Year Net Profit is calculated from Equation 4-7.

[a] Source EIA. Lowest monthly oil and natural gas prices from October 2022 to September 2023: Oil price is West Texas Intermediate $70.25/bbl; See https://www.eia.gov/dnav/pet/hist/rwtcM.htm. Natural gas price is Henry Hub, $2.15/mcf; See https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.

[b] Subtotals are averages for oil and natural gas wells with the 10 BOE per day or less range.

[c] Subtotals are averages for all oil and natural gas wells with 15 BOE per day or less.

Table 4-11 Estimated Revenues, Costs, and Profits for Marginal Wells for 2021: High Oil and Natural Gas Prices

Production rate bracket (BOE/d)	Oil Wells: One Year Gross Revenue	Oil Wells: Operating Cost	Oil Wells: One Year Net Profit	Gas Wells: One Year Gross Revenue	Gas Wells: Operating Cost	Gas Wells: One Year Net Profit
0–1	$ 8,329	$ 4,317	$ 4,012	$ 3,909	$ 4,426	$ (517)
1–2	$ 36,549	$ 8,799	$ 27,750	$ 15,155	$ 8,547	$ 6,608
2–4	$ 71,784	$ 14,492	$ 57,292	$ 30,895	$ 14,138	$ 16,757
4–6	$ 121,010	$ 22,645	$ 98,366	$ 53,242	$ 21,948	$ 31,293
6–8	$ 169,735	$ 30,749	$138,986	$ 75,408	$ 29,664	$ 45,744
8–10	$ 217,533	$ 38,769	$178,764	$ 97,977	$ 37,427	$ 60,550
Subtotal <=10[a]	$ 48,699	$ 10,870	$ 37,829	$ 25,017	$ 11,933	$ 13,084
10–12	$ 264,825	$ 46,776	$218,049	$ 119,937	$ 45,130	$ 74,807
12–15	$ 322,355	$ 56,594	$265,761	$ 146,976	$ 54,589	$ 92,387
Subtotal <=15[b]	$ 63,826	$ 13,392	$ 50,435	$ 33,449	$ 14,882	$ 18,567

Note: One year of financial estimates for marginal oil and natural gas wells using high oil and natural gas prices. One Year Gross Revenue is estimated using Equation 4-5. Operating costs are fixed plus variable costs as calculated by Equation 4-6, using parameters from Table 4-8. One Year Net Profit is calculated from Equation 4-7.
[a] Source EIA. Highest monthly oil and natural gas prices from October 2022 to September 2023: Oil price is West Texas Intermediate, $89.43/bbl; See https://www.eia.gov/dnav/pet/hist/rwtcM.htm. Natural gas price is Henry Hub, $5.66/mcf; See https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.
[b] Subtotals are averages for oil and natural gas wells with the 10 BOE per day or less range.
[c] Subtotals are averages for all oil and natural gas wells with 15 BOE per day or less.

4.2.4 Marginal Wells Financial Analysis Caveats and Limitations

The goal of this analysis is to evaluate the profitability of marginal wells under a certain set of assumptions. We are not able to evaluate other empirical considerations with this analysis.

Marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons. Wells that would otherwise be left in a low-producing or idled state for many years because the costs of plugging are too high can benefit from federal subsidies to reduce, or completely cover the costs of plugging. The Inflation Reduction Act (IRA) provides $700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to $350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds.[111] The goal of marginal well funding from the IRA is to offset the cost of plugging low producing wells. The costs of plugging can vary widely depending on well characteristics and by state. Estimates range from less than $1,000 to over $1 million, with an average of about $75,000 per well (Raimi et al., 2021). It has been reported that in some cases those costs can be reduced to around $25,000, although it is not clear if the methods used could be more broadly applied.[112]Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s). To maintain transparency for the responsible owner or operator and prevent well sites from becoming orphaned, EPA is finalizing the rule with a well closure plan requirement which requires fugitive monitoring of well sites for the life of the well and can only be discontinued if the well site is properly plugged and an OGI survey is done to ensure there are no emissions from the site. EPA is also requiring owners and operators to submit, through an annual ownership report, changes in ownership at individual well sites so it is clear who the responsible owners and operators are until the site is plugged and closed and fugitive emissions monitoring is no longer required.

Through accounting practices and discounting, the costs associated with plugging wells can be delayed far into the future. This delay effectively reduces the present value of costs to the owners and operators and increases the firm's profitability in the short run. Thus, by changing the financial break-even point for when to close the low producing well, owner/operators can extend the well's production period and push the decision to shut-in the well further into the future.

Federal and state tax-credits are available for owners and operators of marginal oil and gas wells in a low commodity price environment. These tax credits reduce the cost of owning marginal wells.[113] At the federal level, wells that produce no more than 25 BOE per day can qualify for the credit. With no limit on the number of wells that can qualify for the credit, each well can receive a tax credit on up to 1,905 BOE of total production per year. The credit value for marginal gas wells is based on the reference natural gas price published by the Internal Revenue Service (IRS); in 2021, the maximum value was $4,336 per well. Any unused portion

[111] See: https://www.grants.gov/web/grants/view-opportunity.html?oppId=349508.
[112] See: https://www.bloomberg.com/features/diversified-energy-natural-gas-wells-methane-leaks-2021/.
[113] See: https://crsreports.congress.gov/product/pdf/IF/IF11528.

of the tax credit can either be carried back five years or forward 20 years. The current tax credit applies when the reference price of natural gas is below $2 per mcf.[114] For marginal oil wells, the reference price is $15 per barrel of oil.[115] Since the amount of the credit is phased out when oil prices are greater than the reference price, high oil prices relative to the reference price means the marginal oil credit has not been available in recent years.

State bonding requirements are sometimes insufficient to cover the costs of plugging wells. Blanket bonds that an operator takes out to cover all their wells in a state are especially problematic as the fixed amount that is set aside is often too low to cover the plugging costs for an operator with many wells (Ho et al., 2018).

Accounting practices that enable the delay of plugging costs, tax subsidies, and low bonding requirements that may incentivize owners/operators to continue to operate a marginal well that is barely or is not profitable are all considerations that may impact the owner/operator's decision on whether to shut-in and plug a well. A simple break-even analysis that only evaluates well profitability in a single time-period can help shed light on whether the well has a higher likelihood of shutting-in, but it doesn't capture the full decision-making process. That is, a single period of losses most likely will not cause a firm to shut-in and plug a well but larger, sustained losses over many years could. Thus, it seems that costs must be much larger than any benefits of delay, including expected gains from production, before a well is realistically at risk for being shut-in and plugged. The uncertainty surrounding future oil and gas production, commodity prices, tax treatments, and regulatory regimes, also contributes to the difficulty in predicting when or if an operator decides to shut-in and plug any given well. This uncertainty also makes it extremely difficult to determine the full impact of regulation on the financial status of marginal well owners.

Further, because regulatory costs are dependent on, among other things, types of equipment used at well sites, the full impact of regulation on the financial status of marginal well owners cannot be determined. The age, location, and what is produced from each marginal well

[114] See: https://www.irs.gov/pub/irs-irbs/irb23-23.pdf.
[115] See: https://www.irs.gov/irb/2023-26_IRB.

also contribute to differences in baseline regulatory costs. This adds heterogeneity to the regulatory cost burdens on owners and adds complexity to estimating impacts.

The financial condition of the owners and operators of the marginal wells is unknown. It is likely that some of them are financially distressed, but unavailable data makes it near impossible to determine conclusively. Thus, the EPA is unable to assess the viability of the owners and operators of the marginal wells, and as such, the EPA is therefore unable to predict which firms will be most adversely affected by regulatory costs.

There is a market for buying and selling marginal wells, and it is possible that not only could current market participants increase their holdings of marginal wells, but new participants could also enter the market. For example, Diversified Energy, headquartered in Birmingham, Alabama, is reported to be the largest owner oil and natural gas wells in the country, with a large percentage being marginal wells.[116] Diversified Energy describes its business strategy as acquiring uneconomic wells that are low-cost, low decline wells that are expected to continue producing far into the future. Diversified owns wells throughout Appalachia and has also begun purchasing wells in Louisiana and Texas. It is conceivable that as more marginal wells become uneconomic through market conditions, regulatory costs, and declining production other firms will find it advantageous to buy these low-producing wells from the current owners.

Because of their low production, some marginal wells are temporarily shut-in and production is paused. This can happen for a variety of reasons including maintenance and repair. While these wells can restart production, the decision to do so typically relies on the geologic properties of the reservoir. In cases where the marginal well is shut-in for an extended period, restarting production can be difficult and even impossible. This temporary pausing of production further complicates the analysis effort.

The decision to plug a well can be described as an optimal stopping problem. Provencher (1997), Pindyck (2002), Kellogg (2014), and others have used a dynamic framework to model similar types of problems in the natural resource sector. While such an analysis is not undertaken here, the methods used to solve such problems are complex and require data that is currently unavailable.

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[116] See: https://ohiorivervalleyinstitute.org/wp-content/uploads/2022/04/Diversified-Energy-Report-FINAL-1.pdf.

4.3 Environmental Justice Analyses

E.O. 12898 directs the EPA to "achiev[e] environmental justice (EJ) by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects" (59 FR 7629, February 16, 1994), termed disproportionate impacts in this chapter. Additionally, E.O. 13985 was signed to advance racial equity and support underserved communities through Federal government actions (86 FR 7009, January 20, 2021). Recently, E.O. 14096 (88 FR 25251, April 26, 2023) strengthens the directives for achieving environmental justice that are set out in E.O. 12898.

E.O. 14096 defines EJ as the just treatment and meaningful involvement of all people, regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other Federal activities that affect human health and the environment. The EPA further defines the term fair treatment to mean that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies".[117] Meaningful involvement means that: (1) potentially affected populations have an appropriate opportunity to participate in decisions about an 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.[118] 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

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

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

groups of concern for both the baseline and final regulatory options, using the best available information (both quantitative and qualitative) to inform the decision-maker and the public.

A regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on populations or communities of concern based on income, race, color, national origin, Tribal affiliation, or disability; (2) exacerbate existing disproportionate impacts on populations or communities of concern; or (3) present opportunities to address existing disproportionate impacts on populations or communities of concern through the action under development.

Under E.O. 13563, federal agencies may consider equity, human dignity, fairness, and distributional considerations, where appropriate and permitted by law. E.O. 14094 directs Federal agencies to recognize distributive impacts and equity in regulatory analysis, to the extent permitted by law, as practicable and appropriate.[119] For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis",[120] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance.

A reasonable starting point for assessing the need for a more detailed EJ analysis is to review the available evidence from the published literature and from community input on what factors may make population groups of concern more vulnerable to adverse effects (e.g., underlying risk factors that may contribute to higher exposures and/or impacts). It is also important to evaluate the data and methods available for conducting an EJ analysis. EJ analyses can be grouped into two types, both of which are informative, but not always feasible for a given rulemaking:

1. Baseline Analysis: Describes the current (pre-control) distribution of exposures and risk and identifies potential disparities.

[119] 88 FR 21879

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

2. Policy Analysis: Describes the distribution of exposures and risk after the regulatory option(s) have been applied (post-control) and identifies how potential disparities change in response to the rulemaking.

EPA's 2016 Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting EJ analyses. However, a key consideration is consistency with the assumptions underlying other parts of the regulatory analysis when evaluating the baseline and regulatory options.

4.3.1 Analyzing EJ Impacts in this Final Action

In addition to the benefits assessment (Chapter 3), the EPA considers potential EJ concerns of this rulemaking. An EJ concern is defined as the actual or potential lack of fair treatment or meaningful involvement on the basis of income, race, color, national origin, Tribal affiliation, or disability in the development, implementation and enforcement of environmental laws, regulations, and policies. For analytic purposes, this concept refers more specifically to disproportionate and adverse impacts that may exist prior to or be created by the final regulatory action (U.S. EPA, 2015). Although EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, the EPA's EJ Technical Guidance (U.S. EPA, 2015) states that "[t]he analysis of potential EJ concerns for regulatory actions should address three questions:

1. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?
2. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?
3. For the regulatory option(s) under consideration, are potential EJ concerns created [, exacerbated,] or mitigated compared to the baseline?"

To address these questions, the EPA developed an analytical approach that considers the purpose and specifics of this rulemaking, as well as the nature of known and potential exposures and health impacts. Oil and natural gas operations in the U.S. include a variety of emission sources for methane, VOC, and HAP, including wells, well sites, processing plants, compressor stations, storage equipment, and natural gas transmission and distribution lines. These emission points are located throughout much of the country, though many of these emissions sources are concentrated in particular geographic regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas natural gas compressor stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density. The rulemaking is also expected to reduce ambient ozone from VOC emission reductions across the continental U.S.

For purposes of this RIA, the EPA performed quantitative analyses of proximity to emissions sources, the distribution of exposures from the regulated sector, the demographics of employees in the regulated sector and of communities whose employment is disproportionately in the regulated sector, and of impacts on consumers, as well as qualitative analyses of climate vulnerabilities. The quantitative analyses use different measures of possible groups of concern because each focuses on different channels of possible impact. The analysis of employment impacts and the analysis of oil and gas intensive communities focus on characteristics which may affect workers' ability to find work in other sectors. The analysis of household energy expenditures characterizes how household energy expenditures vary across the income distribution and for different racial and ethnic groups, with a goal to highlight which populations may be most vulnerable to potential energy market effects caused by regulatory impacts.

While the qualitative discussion of climate EJ impacts (Section 4.3.24.3.2) and the baseline assessments of air toxic EJ impacts (Section 4.3.44.3.44.3.4), demographic EJ impacts of workers and communities (Section 4.3.54.3.5), and household energy expenditures by demographic group (Section 4.3.64.3.64.3.6) remain largely similar to what was included in the proposal and supplemental proposal RIAs, we have improved the quantitative assessment of ozone EJ exposure impacts from oil and natural gas VOC emissions (Section 4.3.34.3.3). As policy-specific ozone-season air quality surfaces were generated to estimate human health benefits, we also evaluated a subset of these air quality surfaces for EJ ozone exposure from VOC. We also evaluated EJ ozone exposure impacts in additional potentially overburdened populations (e.g., redlined areas) and developed population subgroups that represent differences in cumulative environmental exposures (e.g., life expectancy) and specifically identify geographically similar communities of Indigenous populations that may have potential EJ concerns (e.g., Tribal lands).

4.3.2 Qualitative Discussion of Disparate Climate Vulnerabilities in the Baseline

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; including those that have been historically marginalized or overburdened; 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), the IPCC, the National Research Council, and the National Academies of Science, Engineering, and Medicine add more evidence that the impacts of climate change raise potential EJ concerns (IPCC, 2018; National Academies, 2017; National Research Council, 2011; Oppenheimer et al., 2014; Porter et al., 2014; Smith et al., 2014; USGCRP, 2016, 2018). These reports conclude that less-affluent, traditionally marginalized, 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 (e.g., Black and Hispanic/Latino communities; Native Americans, particularly those living on Tribal lands and Alaska Natives), may be uniquely vulnerable to climate change health impacts in the United States, as discussed below. In particular, the 2016 scientific assessment on the *Impacts of Climate Change on Human Health* 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 (USGCRP, 2016).

Per the Fourth National Climate Assessment, “Climate change affects human health by altering exposures to heat waves, floods, droughts, and other extreme events; vector-, food- and waterborne infectious diseases; changes in the quality and safety of air, food, and water; and stresses to mental health and well-being” (Ebi et al., 2018). Many health conditions such as cardiopulmonary or respiratory illness and other health impacts are associated with and exacerbated by an increase in greenhouse gases and climate change outcomes, which is problematic as these diseases occur at higher rates within vulnerable communities. Importantly, negative public health outcomes include those that are physical in nature, as well as mental, emotional, social, and economic.

The scientific assessment literature, including the aforementioned reports, demonstrates that there are myriad ways in which these populations may be affected at the individual and community levels. Outdoor workers, such as construction or utility workers and agricultural laborers, who are frequently part of already at-risk groups, are exposed to poor air quality and extreme temperatures without relief. Furthermore, individuals within EJ populations of concern face greater housing and clean water insecurity and bear disproportionate economic impacts and health burdens associated with climate change effects. They have less or limited access to healthcare and affordable, adequate health or homeowner insurance. The urban heat island effect can add additional stress to vulnerable populations in densely populated cities who do not have access to air conditioning. Finally, resiliency and adaptation are more difficult for economically disadvantaged communities: They tend to have less liquidity, individually and collectively, to move or to make the types of infrastructure or policy changes necessary to limit or reduce the hazards they face. They frequently face systemic, institutional challenges that limit their power to advocate for and receive resources that would otherwise aid in resiliency and hazard reduction and mitigation.

The assessment literature cited in EPA’s 2009 and 2016 Endangerment Findings, as well as *Impacts of Climate Change on Human Health,* also concluded that certain populations and people in particular life stages, including children, are most vulnerable to climate-related health effects (USGCRP, 2016). The assessment literature produced from 2016 to the present strengthens these conclusions by providing more detailed findings regarding related vulnerabilities and the projected impacts youth may experience. These assessments — including the Fourth National Climate Assessment (USGCRP, 2018) and *The Impacts of Climate Change* *on Human Health in the United States* (USGCRP, 2016) — describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events(USGCRP, 2016). In addition, children are among those especially susceptible to allergens, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More generally, these reports note that extreme weather and flooding can cause or exacerbate poor health outcomes by affecting mental health because of stress; contributing to or worsening existing conditions, again due to stress or also as a consequence of exposures to water and air pollutants; or by impacting hospital and emergency services operations(Ebi et al., 2018). Further, in urban areas in particular, flooding can have significant economic consequences due to effects on infrastructure, pollutant exposures, and drowning dangers. The ability to withstand and recover from flooding is dependent in part on the social vulnerability of the affected population and individuals experiencing an event (National Academy of Sciences, 2019).

The Impacts of Climate Change on Human Health also found that some communities of color, low-income groups, people with limited English proficiency, and certain immigrant groups (especially those who are undocumented) live with many of the factors that contribute to their vulnerability to the health impacts of climate change (USGCRP, 2016). While difficult to isolate from related socioeconomic factors, race appears to be an important factor in vulnerability to climate-related stress, with elevated risks for mortality from high temperatures reported for Black individuals compared to White individuals after controlling for factors such as air conditioning use. Moreover, people of color are disproportionately exposed to air pollution based on where they live, and disproportionately vulnerable due to higher baseline prevalence of underlying diseases such as asthma, so climate exacerbations of air pollution are expected to have disproportionate effects on these communities.

The recent EPA report on climate change and social vulnerability examined four socially vulnerable groups (individuals who are low income, minority, without high school diplomas, and/or 65 years and older) and their exposure to several different climate impacts (air quality, coastal flooding, extreme temperatures, and inland flooding) (U.S. EPA, 2021c). This report found that African-American individuals were 40 percent more likely to currently live in areas with the highest projected increases in mortality rates due to climate-driven changes in extreme temperatures, and 34 percent more likely to live in areas with the highest projected increases in childhood asthma diagnoses due to climate-driven changes in particulate air pollution. The report found that Hispanic individuals are 43 percent more likely to live in areas with the highest projected labor hour losses in weather-exposed industries due to climate-driven warming, and 50 percent more likely to live in coastal areas with the highest projected increases in traffic delays due to increases in high-tide flooding. The report found that American Indian and Alaska Native individuals are 48 percent more likely to live in areas where the highest percentage of land is projected to be inundated due to sea level rise, and 37 percent more likely to live in areas with high projected labor hour losses. Asian individuals were found to be 23 percent more likely to live in coastal areas with projected increases in traffic delays from high-tide flooding. Those with low income or no high school diploma are about 25 percent more likely to live in areas with high projected losses of labor hours, and 15 percent more likely to live in areas with the highest projected increases in asthma due to climate-driven increases in particulate air pollution, and in areas with high projected inundation due to sea level rise.

Indigenous communities possess unique vulnerabilities to climate change, particularly those communities impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Indigenous communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The IPCC indicates that losses of customs and historical knowledge may cause communities to be less resilient or adaptable (Porter et al., 2014). The Fourth National Climate Assessment (2018) noted that while Indigenous peoples are diverse and will be impacted by the climate changes universal to all Americans, there are several ways in which climate change uniquely threatens Indigenous peoples' livelihoods and economies (Jantarasami et al., 2018; USGCRP, 2018). In addition, there can be institutional barriers to their management of water, land, and other natural resources that could impede adaptive measures.

For example, Indigenous agriculture in the Southwest is already being adversely affected by changing patterns of flooding, drought, dust storms, and rising temperatures leading to increased soil erosion, irrigation water demand, and decreased crop quality and herd sizes. The

Confederated Tribes of the Umatilla Indian Reservation in the Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat. Housing and sanitary water supply infrastructure are vulnerable to disruption from extreme precipitation events. Confounding general Native American response to natural hazards are limitations imposed by policies such as the Dawes Act of 1887 and the Indian Reorganization Act of 1934, which ultimately restrict Indigenous peoples' autonomy regarding land-management decisions through Federal trusteeship of certain Tribal lands and mandated Federal oversight of management decisions.

Additionally, the Fourth National Climate Assessment noted that Indigenous peoples are subjected to institutional racism effects, such as poor infrastructure, diminished access to quality healthcare, and greater risk of exposure to pollutants. Consequently, Native Americans often have disproportionately higher rates of asthma, cardiovascular disease, Alzheimer's, diabetes, and obesity, which can all contribute to increased vulnerability to climate-driven extreme heat and air pollution events. These factors also may be exacerbated by stressful situations, such as extreme weather events, wildfires, and other circumstances.

The Fourth National Climate Assessment and IPCC AR5 also highlighted several impacts specific to Alaskan Indigenous Peoples (Porter et al., 2014). Coastal erosion and permafrost thaw will lead to more coastal erosion, rendering winter travel riskier and exacerbating damage to buildings, roads, and other infrastructure – these impacts on archaeological sites, structures, and objects that will lead to a loss of cultural heritage for Alaska's Indigenous people. In terms of food security, the Fourth National Climate Assessment discussed reductions in suitable ice conditions for hunting, warmer temperatures impairing the use of traditional ice cellars for food storage, and declining shellfish populations due to warming and acidification. While the Fourth National Climate Assessment also noted that climate change provided more opportunity to hunt from boats later in the fall season or earlier in the spring, the assessment found that the net impact was an overall decrease in food security.

4.3.3 Ozone from Oil and Natural Gas VOC Emission Impacts

We evaluate the potential for EJ concerns among potentially vulnerable populations resulting from exposure to ozone due to VOC emissions from the oil and gas sector under the baseline and policy option in this rule. This was done by characterizing the distribution of ozone exposures both in the baseline and for following the implementation of the regulatory option in 2038. The air quality surface for this analytic year was selected from the four available air quality surfaces as the surfaces for 2024, 2027, 2028, and 2038 were all similar in both magnitude of predicted ozone concentrations and spatial distribution.

As this analysis is based on the same ozone spatial fields as the benefits assessment (see showing the spatial fields), it is subject to similar types of uncertainty (see Section 3.3.7 for a discussion of uncertainty). A particularly germane limitation for this analysis is that the expected concentration changes are quite small, likely making uncertainties associated with the various input data more relevant.

This EJ air pollutant exposure analysis aims to evaluate the potential for EJ concerns related to ozone exposures among potentially vulnerable populations.[121,122] To assess EJ ozone exposure impacts, we focus on the first and third of the three EJ questions from the EPA's 2016 EJ Technical Guidance.[123] The first questions asks if there are potential EJ concerns associated with stressors affected by the regulatory action for population groups of concern in the baseline. The third question asks if those potential EJ concerns in the baseline are exacerbated, unchanged, or mitigated under the regulatory option being considered.[124]

To address these questions with respect to ozone exposures, EPA developed an analytical approach that considers the purpose and specifics of this final rulemaking, as well as the nature

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[121] The term exposure is used here to describe estimated average warm-season ozone concentrations and not individual dosage.

[122] Air quality surfaces used to estimate exposures are based on 12 km by 12 km grids. Additional information on air quality modeling can be found in the air quality modeling information section.

[123] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions. https://www.epa.gov/sites/default/files/2015-06/documents/considering-ej-in-rulemaking-guide-final.pdf

[124] EJ question 2, which asks if there are potential EJ concerns (i.e., disproportionate burdens across population groups) associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory options under consideration, was not focused on for several reasons. Importantly, the total magnitude of differential exposure burdens with respect to ozone among population groups at the national scale has been fairly consistent pre- and post-policy implementation across recent rulemakings. As such, differences in nationally aggregated exposure burden averages between population groups before and after the rulemaking tend to be very similar. Therefore, as disparities in pre- and post-policy burden results appear virtually indistinguishable, the difference attributable to the rulemaking can be more easily observed when viewing the change in exposure impacts, and as we had limited available time and resources, we chose to provide quantitative results on the pre-policy baseline and policy-specific impacts only, which related to EJ questions 1 and 3. We do however use the results from questions 1 and 3 to gain insight into the answer to EJ question 2 in the summary (Section 4.3.7).

of known and potential exposures and impacts. Specifically, as 1) this final rule affects oil and natural gas sources across the U.S., which are numerous and vary in emission levels, and 2) ozone can undergo long-range transport, it is appropriate to conduct an EJ assessment of the contiguous U.S. Given the availability of modeled ozone air quality surfaces under the baseline and final regulatory option, we conduct an analysis of changes in ozone concentrations modeled to occur under the final rule as compared to the baseline scenario, characterizing average and distributional exposures following implementation of the regulatory option in the implementation year 2038. However, several important caveats of this analysis are as follows:

- The baseline scenario for 2038 represents expected emissions from oil and natural gas sources covered by these rules in 2038 but includes emissions from all other sources that are only projected to the year 2026. The 2038 baseline therefore does not capture any anticipated changes in ambient ozone by 2038 that would occur due to emissions changes from sources other than oil and natural gas sources covered by this rulemaking.

- Modeling of post-policy air quality concentration changes are based on state-level emission data paired with baseline 2038 emissions projections for oil and natural gas sources based on version 2 of the EPA's 2016 emissions modeling platform (U.S. EPA, 2022). While the baseline spatial patterns represent ozone concentrations associated with the projected 2026 oil and natural gas emissions, the post-policy air quality surfaces will capture expected ozone changes that result from state-to-state emissions changes but will not capture any spatially heterogenous changes in oil and natural gas emissions within a single state except for changes captured by separating out emissions changes occurring in the three Texas sub-regions. While the methodology applied to create the ozone surfaces does not allow us to consider the effects of any changes to spatial distribution of oil and natural gas emissions within a state between the 2026 modeled case and the baseline and regulatory alternatives in this RIA, the within-state spatial patterns do represent locations of oil and natural gas emissions in 2026. This provides a reasonable estimate of where change in oil and gas emissions will occur from this rulemaking since, in the timeframe of the analysis for this rulemaking, new facilities are likely to be located in the same major basins as facilities as represented by the 2026 projections.

- Air quality simulation input information are at a 12 km by 12 km grid resolution and population information is either at the Census tract- or county-level, potentially masking impacts at geographic scales more highly resolved than the input information.

- The specific air pollutant metric evaluated in this assessment, warm season maximum daily eight-hour ozone average concentrations, is focused on longer-term exposures that have been linked to adverse health effects. This assessment does not evaluate disparities in other potentially health-relevant metrics, such as shorter-term exposures to ozone.

- Ozone EJ impacts were limited to exposures, and do not extend to health effects, given additional uncertainties associated with estimating health effects stratified by demographic population and the ability to predict differential ozone-attributable EJ health impacts.

Population variables considered in this EJ exposure assessment include race, ethnicity, educational attainment, employment status, health insurance status, linguistic isolation, poverty status, age, and sex (Table 4-12).[125] Three additional population variables were included in this analysis that were not included in previous RIAs (historically redlined areas, Tribal lands, and life expectancy), one of which one is a measure of cumulative impacts (life expectancy) .

The variable "redlined areas" was added to this RIA to assess exposure in communities with a legacy of discriminatory land use designations and siting decisions (i.e., historically redlined areas). We use graded census tracts developed by Noelke et al. (2022) from digitized Home Owners' Loan Corporation (HOLC) residential security maps overlaid onto 2010 Census tracts. Each census tract is classified as being covered by "Mainly A," "Mainly B," "Mainly C," and "Mainly D" grading, corresponding to coverage of different hazard ratings from original HOLC maps. The dataset covers 14,818 census tracts, since HOLC maps only covered certain urban areas. This dataset was adapted to cover 72,538 census tracts for use in BenMAP, with the remaining census tracts categorized as "redlined_na" since they were not covered by HOLC grading. Census tracts labeled as "Mainly D" were categorized as "redlined" and census tracts that were mainly A-C were categorized as "not_redlined." The practice of redlining was in effect across 239 cities and, although illegal now for many decades, has had lasting effects on investments in "redlined" neighborhoods where greater proportions of low income and people of

[125] Population projections stratified by race/ethnicity, age, and sex are based on economic forecasting models developed by Woods and Poole (2015). The Woods and Poole database contains county-level projections of population by age, sex, and race out to 2060, 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. Projections in each county are determined simultaneously with every other county in the U.S. to consider patterns of economic growth and migration. The sum of growth in county-level populations is constrained to equal a previously determined national population growth, based on Bureau of Census estimates (Hollmann et al., 2000). According to Woods and Poole, linking county-level growth projections together and constraining to a national-level total growth avoids potential errors introduced by forecasting each county independently. 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).

color still reside and tend to have poorer health outcomes (Lee et al., 2022; Mitchell & Franco, 2018; Noelke et al., 2022; Swope et al., 2022).

The addition of Tribal lands, as defined by the Bureau of Indian Affairs, enhanced our analysis relative to previous RIAs by addressing previous issues with undercounting American Indians[126] and serving as a health metric for communities of Tribal populations. Additionally, the American Indian population as a whole includes individuals who live on non-Tribal lands who have different exposures and access to resources than those individuals who live on Tribal lands, so the Tribal lands variable is a community health metric (based on residency in a specifically designated Tribal lands location) rather than a population health metric (based on membership in a specific population subgroup, regardless of location). Thus, evaluating exposures on Tribal lands (vs. non-Tribal lands) may better characterize true disparities in exposures among American Indians.

Lastly, as one way to assess cumulative exposures and impacts, the life expectancy variable has been added to differentiate between populations with differing baseline health levels and measures the average life expectancy within a census tract. For average life expectancy, low values indicate a higher overall burden or cumulative risk, while higher values indicate a lower overall burden or cumulative risk. The life expectancy data comes from CDC's U.S. Small-area Life Expectancy Estimates Project (USALEEP), which produced census tract-level life expectancy estimates at birth for the period 2010-2015 which have been used in other analysis tools such as NEXUS and CEJST.

The data sources and processing methodology for each dataset are described below. County-level datasets were generated for 3,109 counties in the contiguous U.S.

[126] American Indians are the most under-counted group in the U.S. Census with more than 80% of reservation lands in "hard-to-count (HTC) census tracts" U.S. Department of the Interior, Indian Affairs, see I. Collection of Tribal Enrollment Count | Indian Affairs (bia.gov).

Table 4-12 Demographic Populations Included in the Ozone EJ Exposure Analysis from Oil and Natural Gas VOC Emissions

Population	Groups	Ages	Spatial Scale of Population Data
Race	Asian; American Indian; Black; White	0-99	Census tract
Ethnicity	Hispanic; Non-Hispanic	0-99	Census tract
Educational Attainment	High school degree or more; No high school degree	25-99	Census tract
Employment Status	Employed; Unemployed; Not in the labor force	0-99	County
Health Insurance Status	Insured; Uninsured	0-64	County
Linguistic Isolation	English "well or better"; English < "well"	0-99	Census tract
Poverty Status	Above the poverty line; Below the poverty line	0-99	Census tract
Redlined Areas	HOLC[a] Grades A-C; HOLC Grade D; Not graded by HOLC	0-99	Census tract
Life Expectancy	Top 75%; Bottom 25%	0-99	Census tract
Tribal Land	Tribal land; Not Tribal land	0-99	Census tract
Age	Children; Adults; Older Adults	0-17 18-64 65-99	Census tract
Sex	Female; Male	0-99	Census tract

[a] Home Owners' Loan Corporation (HOLC)

4.3.3.1 National Aggregated Results

We begin by evaluating potential disparities in ozone exposure from VOC emission impacts aggregated across the continental U.S. (i.e., national scale). National average baseline ozone concentrations in parts per billion (ppb) in 2038 are shown in the Figure 4-1 heat map for each population group. Baseline concentrations represent the total estimated ozone exposure burden in the absence of the rulemaking averaged over the April–September warm season average. The concentration values are colored to more easily visualize differences in average concentrations (lighter purple coloring represents lower average concentrations and darker purple coloring represents higher average concentrations). It should be noted that in general, national average ozone exposures in the baseline are relatively low (about 40 ppb), and that the national ozone disparities observed in the baseline are similar to those described by recent rules (e.g., Regulatory Impact Analysis for the Proposed NSPS for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil-Fuel Fired Electric Generating Units).[127] Populations

[127] See https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

exposed to national average ozone concentrations higher than that faced by the reference population of all people aged 0-99 are ordered by the largest to the smallest differences: American Indians, Hispanics, those on Tribal land, those linguistically isolated, Asians, those in historically redlined areas, those who are unemployed, those who are less educated, the insured, children, adults, and Whites (Figure 4-1). Columns labeled “Absolute Reductions” and “Percentage Reductions” provide information regarding how the final rule is projected to reduce warm season average ozone concentrations for the various population groups in the year 2038. Most population groups were predicted to experience national-level ozone concentration reductions of approximately 0.025 ppb (0.06 percent) compared to their baseline ozone concentration exposure. The magnitudes of these ozone concentration reductions across population demographics are all similar and small in magnitude with the exception of those living on Tribal lands who are predicted to experience nearly 3 times as large of a reduction in ozone concentrations as other population groups.

The national-level assessment of ozone exposure with and without implementation of the final rule rulemakings suggests that while EJ exposure disparities are present in the pre-policy scenario, these concerns are not likely mitigated or exacerbated by the rule for the population groups evaluated, due to the similar and small differences in magnitudes of ozone concentration reductions across demographic groups.

Population Groups	Populations (Ages)	2038 Baseline (ppb)	2038 Absolute Reductions (ppb)	2038 Percentage Reductions
Reference	Reference (0-99)	41.1	0.024	0.058
Race	American Indian (0-99)	43.1	0.030	0.070
	Asian (0-99)	42.0	0.019	0.045
	Black (0-99)	39.8	0.022	0.055
	White (0-99)	41.2	0.025	0.061
Ethnicity	Non-Hispanic (0-99)	40.5	0.024	0.059
	Hispanic (0-99)	42.8	0.024	0.056
Educational Attainment	More educated (>24)	40.9	0.024	0.059
	Less educated (>24)	41.5	0.023	0.055
Employment Status	Employed (0-99)	41.1	0.025	0.061
	Unemployed (0-99)	41.5	0.023	0.055
	Not in the labor force (0-99)	41.0	0.024	0.059
Insurance Status	Insured (0-64)	41.2	0.024	0.058
	Uninsured (0-64)	40.7	0.028	0.069
Linguistic Isolation	English "well or better" (0-99)	41.0	0.024	0.059
	English < "well" (0-99)	42.3	0.021	0.050
Life Expectancy	Top 75% (0-99)	41.3	0.023	0.056
	Bottom 25% (0-99)	40.1	0.028	0.070
	Life expectancy data unavailable (0-99)	41.3	0.026	0.063
Poverty Status	>Poverty line (0-99)	41.0	0.024	0.058
	<Poverty line (0-99)	41.1	0.024	0.058
Redlined Areas	HOLC Grades A-C (0-99)	42.0	0.025	0.060
	HOLC Grade D (0-99)	41.2	0.025	0.061
	Not Graded by HOLC (0-99)	40.9	0.024	0.059
Tribal Land	Not Tribal land (0-99)	41.0	0.024	0.058
	Tribal land (0-99)	42.5	0.069	0.162
Ages	Adults (18-64)	41.1	0.024	0.058
	Children (0-17)	41.3	0.025	0.061
	Older Adults (65-99)	40.7	0.023	0.057
Sex	Females (0-99)	41.0	0.024	0.058
	Males (0-99)	41.1	0.024	0.058

Figure 4-1 Heat Map of the National Average Ozone Concentrations in the Baseline and the Absolute and Percentage Reductions under the Final Rule in 2038 (ppb)

4.3.3.2 National Distributional Results

While national average results can provide some insight when comparing across population impacts of EJ ozone exposure impacts from oil and natural gas VOC emission

reductions, they do not provide information on the full distribution of concentration impacts. This is because both demographic groups and ambient concentrations can be unevenly distributed across the spectrum of exposures, meaning that average exposures may mask important spatially localized disparities. To evaluate how the distribution of warm-season exposures varies within and across demographic groups at the county level, we plot the full array of exposures projected to be experienced by the entirety of each population (Figure 4-2 Baseline Distributions of Ozone Concentration (ppb) Across Populations in 2038 under the Final Rule (warm-season average of 8-hour daily maximum)

While national average results can provide some insight when comparing across population impacts of EJ ozone exposure impacts from oil and natural gas VOC emission reductions, they do not provide information on the full distribution of concentration impacts. This is because both demographic groups and ambient concentrations can be unevenly distributed across the spectrum of exposures, meaning that average exposures may mask important spatially localized disparities. To evaluate how the distribution of warm-season exposures varies within and across demographic groups at the county level, we plot the full array of exposures projected to be experienced by the entirety of each population (). Distributional figures present the running sum as a percent of each group's total population on the y-axes (i.e., cumulative percent of population). By constructing the cumulative percent metric, we are able to directly compare warm-season ozone exposures across demographic populations with different population sizes. The x-axes show baseline warm-season ozone concentrations (ppb) from low to high concentrations. Ozone concentrations are county-level averages from all Census tracts in the contiguous U.S. In other words, plots compare the running sum of each population against baseline warm-season ozone concentrations such that populations whose trendlines are further right on the plot have a higher proportion of their population exposed to higher concentrations. For example at the national-level, the proportion of Hispanics and the proportion of non-Hispanics exposed to lower concentrations of ozone is roughly equal because the trendlines overlap on the left side of the plot; however, at higher concentrations of ozone on the right side of the plot, the trendline for Hispanics is further right than for non-Hispanics, which indicates that Hispanics are exposed to higher concentrations of ozone in a larger proportion than non-Hispanics.). Distributional figures present the running sum as a percent of each group's total population on the y-axes (i.e., cumulative percent of population). By constructing the cumulative percent metric, we are able to directly compare warm-season ozone exposures across demographic populations with different population sizes. The x-axes show baseline warm-season ozone concentrations (ppb) from low to high concentrations. Ozone concentrations are county-level averages from all Census tracts in the contiguous U.S.[128] In other words, plots compare the running sum of each population against baseline warm-season ozone concentrations such that populations whose trendlines are further right on the plot have a higher proportion of their population exposed to higher concentrations. For example, at the national-level, the proportion of Hispanics and the proportion of non-Hispanics exposed to lower concentrations of ozone is roughly equal because the trendlines overlap on the left side of the plot; however, at higher concentrations of ozone on the right side of the plot, the trendline for Hispanics is further right than for non-Hispanics, which indicates that Hispanics are exposed to higher concentrations of ozone in a larger proportion than non-Hispanics.

[128] Distributional figures in the proposal RIA EJ exposure assessment were based on county-level averages. While tract-level averages are preferable due to the higher resolution, they required substantial additional computing power (about 10-fold) and generate similar results. Therefore, EPA will select the geographic resolution that is most reasonable in future EJ assessments.

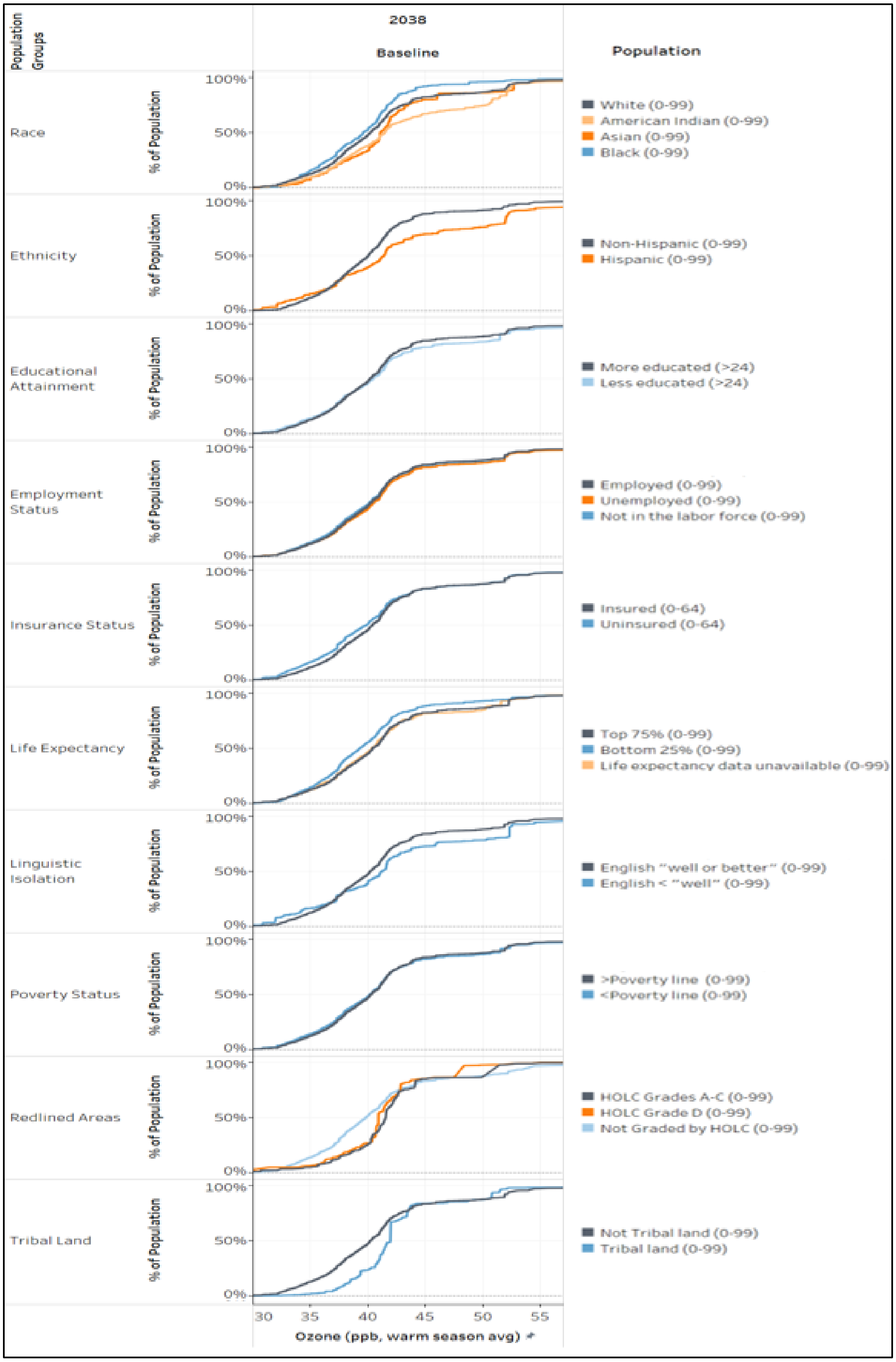

Figure 4-2 Baseline Distributions of Ozone Concentration (ppb) Across Populations in 2038 under the Final Rule (warm-season average of 8-hour daily maximum)

While national average results can provide some insight when comparing across population impacts of EJ ozone exposure impacts from oil and natural gas VOC emission reductions, they do not provide information on the full distribution of concentration impacts. This is because both demographic groups and ambient concentrations can be unevenly distributed across the spectrum of exposures, meaning that average exposures may mask important spatially localized disparities. To evaluate how the distribution of warm-season exposures varies within and across demographic groups at the county level, we plot the full array of exposures projected to be experienced by the entirety of each population (). Distributional figures present the running sum as a percent of each group's total population on the y-axes (i.e., cumulative percent of population). By constructing the cumulative percent metric, we are able to directly compare warm-season ozone exposures across demographic populations with different population sizes. The x-axes show baseline warm-season ozone concentrations (ppb) from low to high concentrations. Ozone concentrations are county-level averages from all Census tracts in the contiguous U.S.[129] In other words, plots compare the running sum of each population against baseline warm-season ozone concentrations such that populations whose trendlines are further right on the plot have a higher proportion of their population exposed to higher concentrations. For example at the national-level, the proportion of Hispanics and the proportion of non-Hispanics exposed to lower concentrations of ozone is roughly equal because the trendlines overlap on the left side of the plot; however, at higher concentrations of ozone on the right side of the plot, the trendline for Hispanics is further right than for non-Hispanics, which indicates that Hispanics are exposed to higher concentrations of ozone in a larger proportion than non-Hispanics.

As the baseline scenario shown in Figure 4-2 Baseline Distributions of Ozone Concentration (ppb) Across Populations in 2038 under the Final Rule (warm-season average of 8-hour daily maximum)

While national average results can provide some insight when comparing across population impacts of EJ ozone exposure impacts from oil and natural gas VOC emission reductions, they do not provide information on the full distribution of concentration impacts.

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[130] See https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

who live on non-Tribal lands. Because those who live on Tribal lands also have higher baseline ozone exposures (Figure 4-1), this larger reduction in ozone exposure can be expected to somewhat mitigate existing disparities in ozone exposure between those who live on Tribal lands and those who do not, even if only to a small degree.

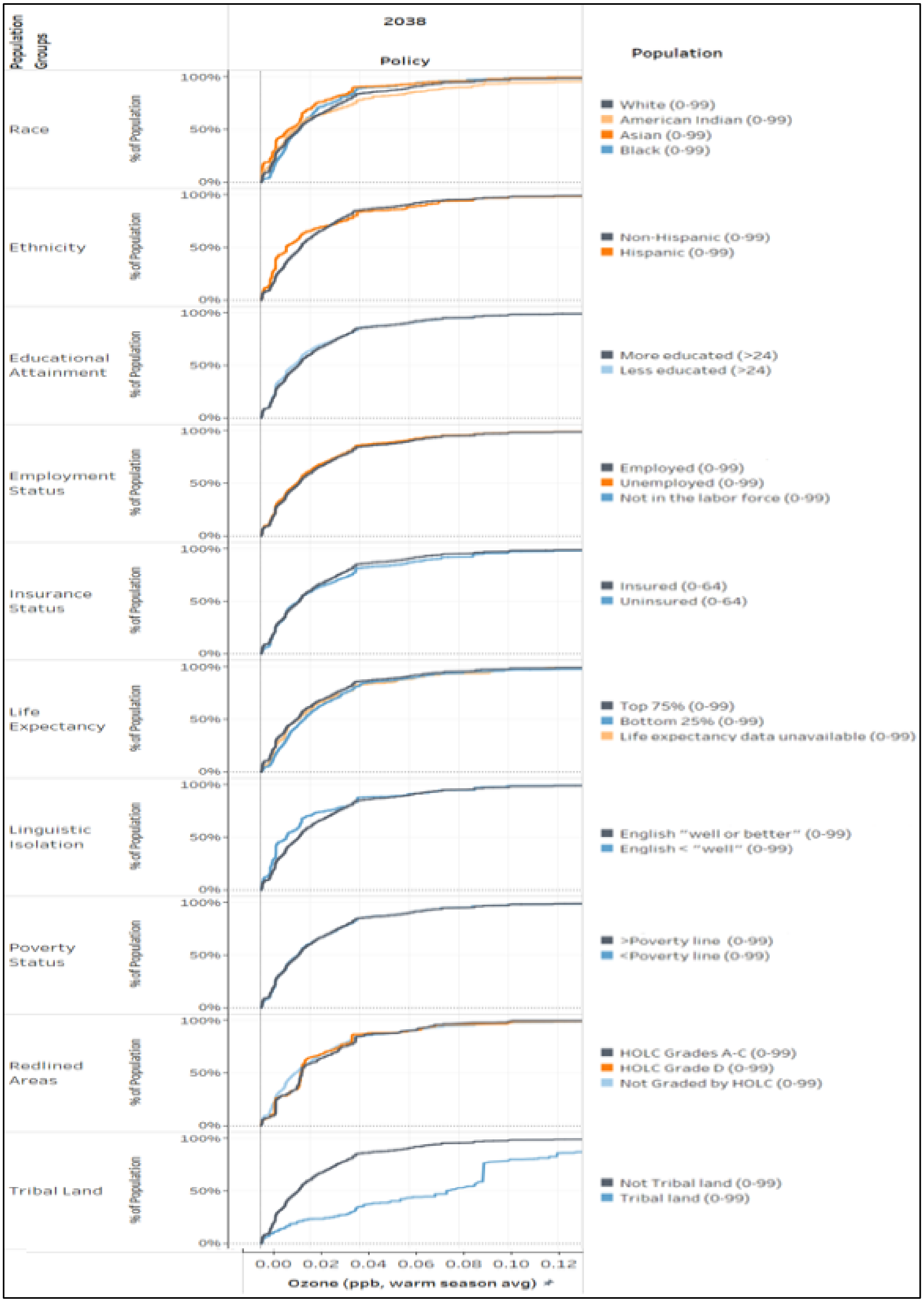

Figure 4-3 Distributions of Ozone Concentration Reductions Across Populations in 2038 under the Final Rule

4.3.3.3 State Aggregated Results

Due to the spatial heterogeneity of EJ ozone exposure from VOC emission impacts, we also provide state-level results that show ozone concentration reductions by state and demographic population in 2038 for the 48 states and the District of Columbia (D.C.) in the contiguous U.S. for the final rule (Figure 4-4). In this heat map, a darker purple shade indicates larger ozone reductions, with demographic groups shown as rows and each state as a column. White cells indicate that certain populations do not exist within a particular state (e.g., there are no Tribal lands or historically redlined areas). The state-specific demographic populations are projected to experience reductions in ozone concentrations of up to 0.185 ppb (observed for those living on non-Tribal lands in Oklahoma in 2038). It is also important to note that there are no observed ozone increases for any population groups across states, only reductions. Figure 4-4 shows that within most states, demographic groups are predicted to experience very similar exposure impacts as the state reference populations.

When comparing exposure impacts across demographic groups within states, most states display similar impacts across demographic groups in 2038. However, some states with higher baseline exposures have larger differences in reductions between groups. For example, in Colorado, which has the fourth highest baseline exposure at 52 ppb in 2038, the largest difference in reductions between the ozone exposure for a population and for the reference population is 0.112 ppb for those living on Tribal land. Uncertainties about the precision of the air quality surfaces in capturing changes of spatial patterns in ozone concentrations within states is discussed above.

Therefore, the state-level assessment of ozone exposure changes due to the final rule suggests that while the final rule will not meaningfully mitigate or exacerbate ozone EJ exposure disparities for most population groups evaluated in 2038, for some population groups, there may be mitigated or exacerbated ozone EJ exposure disparities although at small magnitudes of change. In particular, because baseline ozone concentrations are higher for those who live on Tribal lands, and the expected reduction in ozone exposure is larger for those who live on Tribal lands, the existing disparities in ozone exposure between those who do and don’t live on Tribal lands will be mitigated somewhat, even if only slightly.

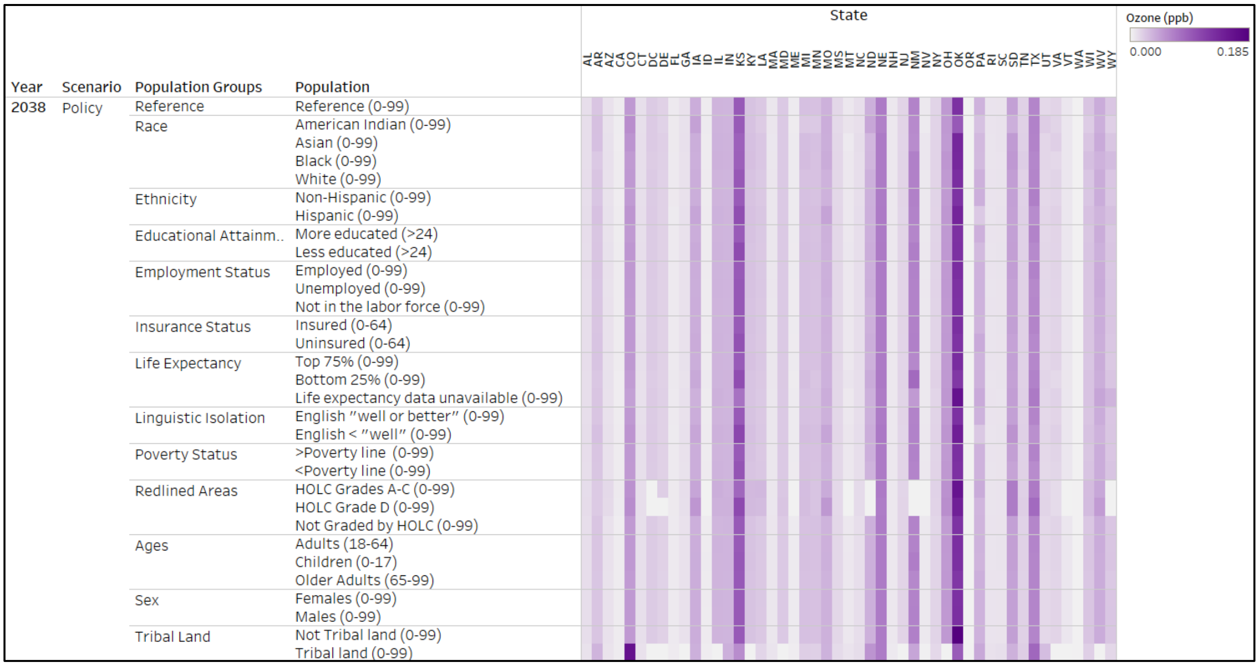

Figure 4-4 Heat Map of the State Average Ozone Concentration Reductions (Purple) Due to the Final Rule Across Demographic Groups in 2038 (ppb)

4.3.4 Air Toxics Impacts

In evaluating the potential for EJ HAP impacts we are only able to sufficiently answer the first of the three EJ questions from EPA's 2016 EJ Technical Guidance — to assess the cancer risks and estimate the demographic breakdown of people living in areas with potentially elevated risk levels associated with baseline HAP emissions from the oil and natural gas sector. To answer the second and third questions regarding comparisons of regulatory options and mitigation to the baseline, we would need detailed location and emissions data for each facility. This would allow us to estimate human health risks at the census block level, which are needed to answer the questions. For the oil and natural gas sector we do not have such detailed data, therefore, in the following paragraphs, we focus on answering the first EJ question.

To estimate HAP risk from this industry sector, we used National Emissions Inventory (NEI) data from 2017, which indicates nationwide emissions of approximately 110,000 tons of HAP for that year from oil and natural gas sources (see Table 3-9Table 3-9). The 2017 NEI includes emissions from the sources subject to regulation and sources outside of the regulation. It does not contain refined emissions estimates from only the sources subject to the regulation. The result of this is that we cannot estimate risks from the source category alone, but rather only from the larger industry sector. This means the source category risks are likely overestimated. Another implication of the data limitations is that the assessment is considered a screen — it is an estimate of potential risks over a broad area. More refined emissions data would be needed to conduct an assessment where we could draw more accurate conclusions about risk to specific areas and populations.

Most of these emissions (97 percent) are treated as "nonpoint" emissions which are allocated from county-level data down to grid cells (4 km in the continental U.S. (CONUS), 9 km in Alaska) based on emissions surrogates. This means that we are making assumptions about the spatial distribution of these emissions that may not be accurate. The approximately 3 percent of emissions that are categorized as "point" in the NEI are emitted from about 400 facilities across the country. For these sources, we can estimate potential exposures and impacts more precisely. Also, we note that some sources categorized as oil and natural gas sources in the NEI are not in the source category for this final rule.

The oil and natural gas sector was one of the sectors assessed in the 2014 National Air Toxics Assessment (NATA). In that assessment, the nonpoint emissions were also modeled as 4 km grid cells in CONUS (9 km grid cells in Alaska) and the point emissions were modeled as point sources in the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) using census blocks as model receptors. However, NATA risk estimates were not presented at census block level because of uncertainties associated with the analysis, such as not knowing exactly where in each grid cell the emissions are occurring. Instead, NATA risk results were presented at census tract level by population-weighting the block risks up to the tract level. Because census tracts can have large areas, the tract-level risks may not reflect potential elevated risks present at a finer scale. The highest tract-level cancer risk from nonpoint oil and natural gas emissions in the 2014 NATA was 30-in-1 million, and only about 30 tracts (out of approximately 74,000 tracts nationwide) had risks greater than 10-in-1 million. For comparison, the nationwide median *total* cancer risk estimate from the 2014 NATA (considering contributions from all source types) was about 30-in-1 million across all census tracts.

Here, using updated emissions and population data, we have conducted a new analysis of HAP-related exposures and risks across the United States. In this analysis, to assess the potential for elevated risks at a scale finer than the census tract level, we aggregated the block-level AERMOD results from the modeling of the 2017 NEI nonpoint HAP emissions to the same 4 km and 9 km grid cells that nonpoint emissions are allocated to. There are about 500,000 4 km grid cells in CONUS, compared to about 74,000 census tracts so, on average, grid cells are at a finer scale than census tract. For each grid cell, we used the median cancer risk of all the blocks that have their internal point (or centroid) located within the grid cell. Census block demographic data were also aggregated to each 4 km grid cell and risks were calculated at the census blocks from the approximately 400 sources included in the 2017 NEI as point sources and added the highest block-level risk for each point source "facility" to the median cell nonpoint risk for the cell containing the block.

The data used in this analysis include spatial data of the grid cells, 2010 census block location and population data,[131] AERMOD-modeled oil and natural gas 2017 HAP concentrations at census block level for the nonpoint and point sources, and 2015–2019 block-group demographic data. There are separate files for the 4 km grid cells that cover CONUS and the 9 km grid cells for Alaska, each using a Lambert Conformal Conic projected coordinate system. These are the same grid definition used for the 2014 NATA nonpoint oil and natural gas emissions. The census data are for the year 2010, with a small number of changes made to the locations (and sometimes deletions) of specific census blocks based on the RTR pre-modeling review of specific source categories since the 2010 census data were first available (the current oil and natural gas AERMOD modeling is based on the census block receptor file as of May 2019). The AERMOD modeling performed (version 19191) using 2017 NEI and meteorology data followed the same methodology used in the 2014 NATA (U.S. EPA, 2018). Demographic data on total population, race, ethnicity, age, education level, low household income, poverty status and linguistic isolation were obtained from the Census' American Community Survey (ACS) 5-year averages for 2015–2019.[132]

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[131] Data Summary File 1 available at http://www2.census.gov/census_2010/04-Summary_File_1/. See also Technical Documentation for the 2010 Census Summary File 1.
[132] Data available at https://www2.census.gov/programs-surveys/acs/summary_file/2019/data/5_year_entire_sf/.

The AERMOD-modeled census block concentrations are based on the 2017 NEI emissions data (see Table 3-9Table 3-9). The process by which emissions were calculated and allocated to grid cells in the case of nonpoint emissions is discussed in the technical support document for the 2017 NEI and the emissions modeling summary for 2017, respectively (U.S. EPA, 2020b). Emissions data are publicly available online.[133] These emissions were modeled in AERMOD (version 19191), and the resulting block-level annual concentrations of each pollutant were used to calculate cancer risks. The pollutant cancer unit risk estimates used to calculate risks are from the toxicity value files available on the Human Exposure Model website.[134] For each census block, the cancer risks were summed over all pollutants to obtain a total cancer risk. The demographic data from the ACS were joined to each census block based on the block group ID (the first 12 characters of the census block ID).

For nonpoint sources, the census blocks were spatially joined to the grid cells (4 km CONUS, 9 km Alaska), and the block data were aggregated at the cell level, using the median cancer risk of the blocks in each cell, and the sum of block populations and the individual demographic group populations (using QGIS version 3.16.3). For point sources, the highest modeled block risk for each facility was added to the median nonpoint risk for the cell containing the block, to provide a measure of total point and nonpoint combined risk.

As noted previously, and discussed further in the next paragraph, there is significant uncertainty in the resulting risk estimates. They are overly conservative due to the inclusion of sources categorized as oil and natural gas sources in the NEI that are not in the source category for this final rule. We estimate that there are approximately 146 million people with nonzero total risk (3 million census blocks) in the gridded AERMOD modeling domain of the CONUS and Alaska nonpoint oil and natural gas sources.[135] The maximum cell risk estimate from oil and natural gas sources is 200-in-1 million, which occurs in two grid cells with an estimated 10 people (3 census blocks); Carbon County, Wyoming (with an estimated 3 people) and Weld County, Colorado (with an estimated 7 people). The CONUS results are summarized in Table 4-13Table 4-13. The population exposed to cancer risk greater than 100-in-1 million for oil and

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[133] Data available at https://gaftp.epa.gov/Air/emismod/2017/AERMOD_inputs/.
[134] See https://www.epa.gov/fera/download-human-exposure-model-hem.
[135] Blocks are within approximately 159,000 4 km CONUS grid cells and approximately 240 9 km Alaska grid cells.

natural gas emissions is approximately 10 people (in two grid cells),[136] and the population exposed to cancer risk greater than or equal to 100-in-1 million is approximately 40,000 people (in 36 grid cells). There are about 140,000 people living (in 122 cells) where the cell risk estimate is greater than or equal to 50-in-1 million and about 6.8 million people living (in 9500 cells) where the cell risk estimate is greater than 1-in-1 million. None of the cells in Alaska has estimated cell cancer risk greater than 1-in-1 million.

It is important to reiterate that these risk estimates are based on emissions from the entire oil and natural gas sector, which includes sources outside the scope of this regulation. To provide some context for how these sources relate to sources impacted by this final regulation, we categorized the fraction of oil and natural gas HAP emissions in the 2017 NEI that were attributed to different source types. For this exercise, we specifically focused on formaldehyde and benzene emissions (the two pollutants that accounted for most of the calculated oil and natural gas HAP risk) in the 36 grid cells with 2017 oil and natural gas HAP risk greater than or equal to 100-in-1 million. It is likely that most of the formaldehyde emissions and about a quarter of the benzene emissions that were categorized as coming from oil and natural gas sources in the 2017 NEI are from sources outside of this source category. Therefore, it also follows that most of the estimated risk is likely being driven by sources not impacted by this final regulation. It bears repeating that this is a screening assessment and full modeling would be required to quantitatively split out risk of sources impacted by this rule from other sources categorized in the NEI as oil and natural gas. Risk in grid cells of interest may not scale directly to emissions within the grid cells.

For the point sources, there were 33 sources with estimated census block maximum cancer risk greater than 1-in-1 million, and only 6 sources with estimated risk greater than 10-in-1 million (highest was 40-in-1 million). There was only a single case where the maximum census block risk from a point source, and the median cell risk from nonpoint sources (containing the census block), were both greater than 10-in-1 million. In that case, the point risk of 20-in-1

[136] Demographic information for grid cells with risks greater than 100-in-1 million are not included in Table 4-13. There are too few census blocks (three) and people (10) to appropriately characterize this population based on the ACS data available.

million and the nonpoint cell risk of 40-in-1 million combined for an estimated 60-in-1 million risk.

Figure 4-5 shows the cell cancer risk estimates in CONUS and Alaska. As indicated in the map, most of the cells in the country (about 150,000 of them) have estimated risk less than 1-in-1 million. Figure 4-6 is a larger-scale map that shows where the estimated cell risks are the highest. The cells with estimated risk greater than or equal to 30-in-1 million are in Colorado, Utah, Wyoming, and North Dakota, and the cells with the highest estimated risk are all in Colorado.

Table 4-13 also contains estimated numbers of people within various demographic groups who live in areas above the specified risk levels. For nearly all the demographic groups the percentage of people in the cells with estimated risk above the specified levels is at or below the national average. Above a risk level of 50-in-1 million, the percent people of color is about the same as the national average, but the Hispanic/Latino demographic group is about 10 percentage points higher than the national average. The overall minority percentage is not elevated compared to the national average because the Black percentage is much lower than the national average. The demographic group of people aged 0–17 is slightly higher than the national average. For people with estimated risk greater than 1-in-1 million, Hispanic/Latino populations and the age 0–17 group are below the national average, but the percentage of Native American populations is higher than the national average. Given that disparities in the baseline are limited, and overall, the regulation is reducing HAP substantially from oil and natural gas sector, we do not expect that any population would experience disbenefits or that disparities would be exacerbated by the final rule.

Table 4-13 Cancer Risk and Demographic Population Estimates for 2017 NEI Nonpoint Emissions from Oil and Natural Gas Sources

	Risks ≥ 100-in-1 million		Risks ≥ 50-in-1 million		Risks > 1-in-1 million		
Number of Cells	36		122		9,499		
Total Population	38,885 (936 census blocks)		142,885 (3,204 census blocks)		6,804,691 (172,878 census blocks)		**Nationwide**
	Population	**%**	**Population**	**%**	**Population**	**%**	**%**
People of Color	13,268	34.1	52,154	36.5	2,010,161	29.5	39.9
Black	140	0.4	1,434	1.0	535,055	7.9	12.2
Native American	77	0.2	465	0.3	59087	0.9	0.7
Other and Multiracial	1,443	3.7	5,148	3.6	323,397	4.8	8.2
Hispanic / Latino	11,608	29.9	45,107	31.6	1,092,621	16.1	18.8
Age 0-17	10,679	27.5	37,487	26.2	1,463,907	21.5	22.6
Age ≥65	4,272	11.0	17,188	12.0	1,085,067	15.9	15.7
Below the Poverty Level	2,000	5.1	13,455	9.4	902,472	13.2	13.4
Over 25 Without a High School Diploma	2,788	7.2	11,320	7.9	488,372	7.2	12.1
Linguistically Isolated	808	2.1	4,418	3.1	179,739	2.6	5.4

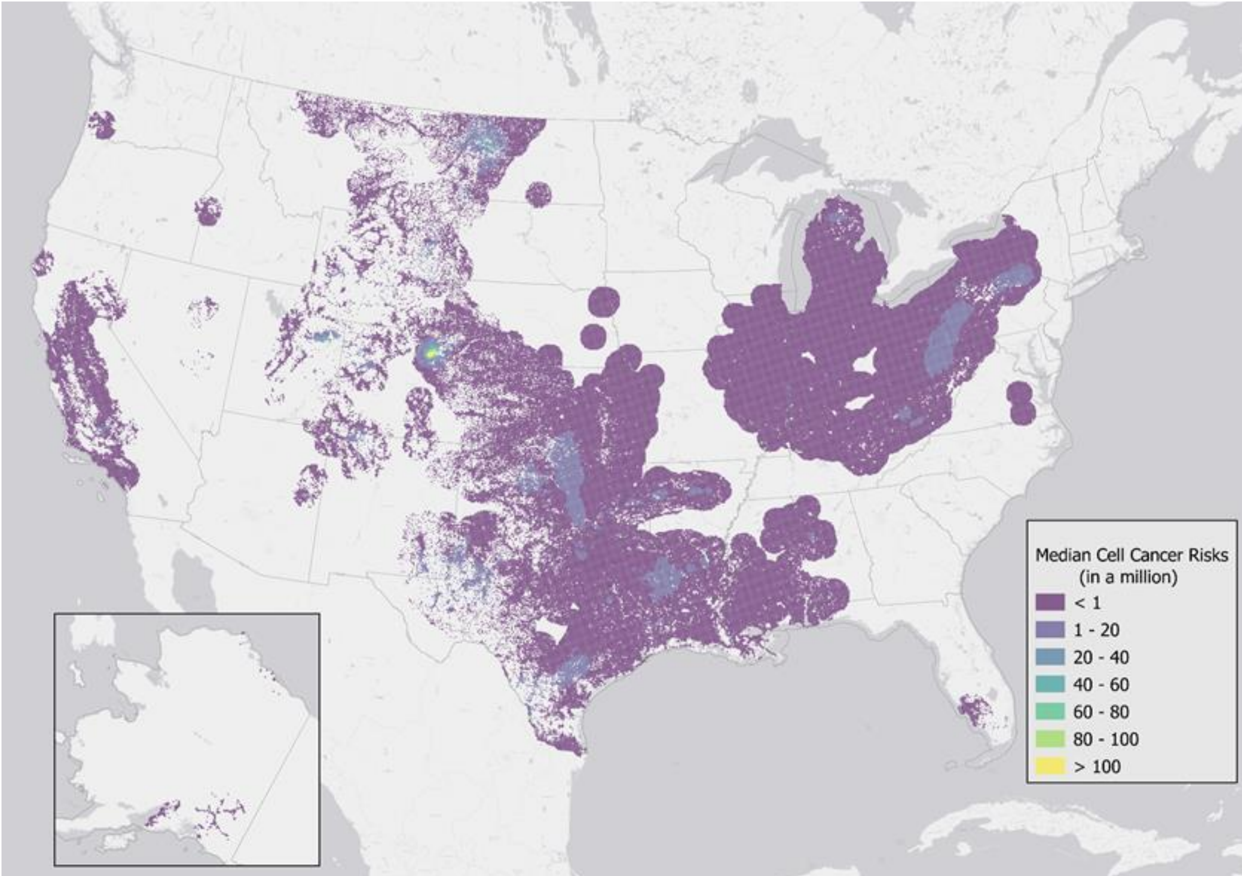

Figure 4-5 National Map of Grid Cell Median Cancer Risks for 2017 Nonpoint Oil and Natural Gas NEI Emissions

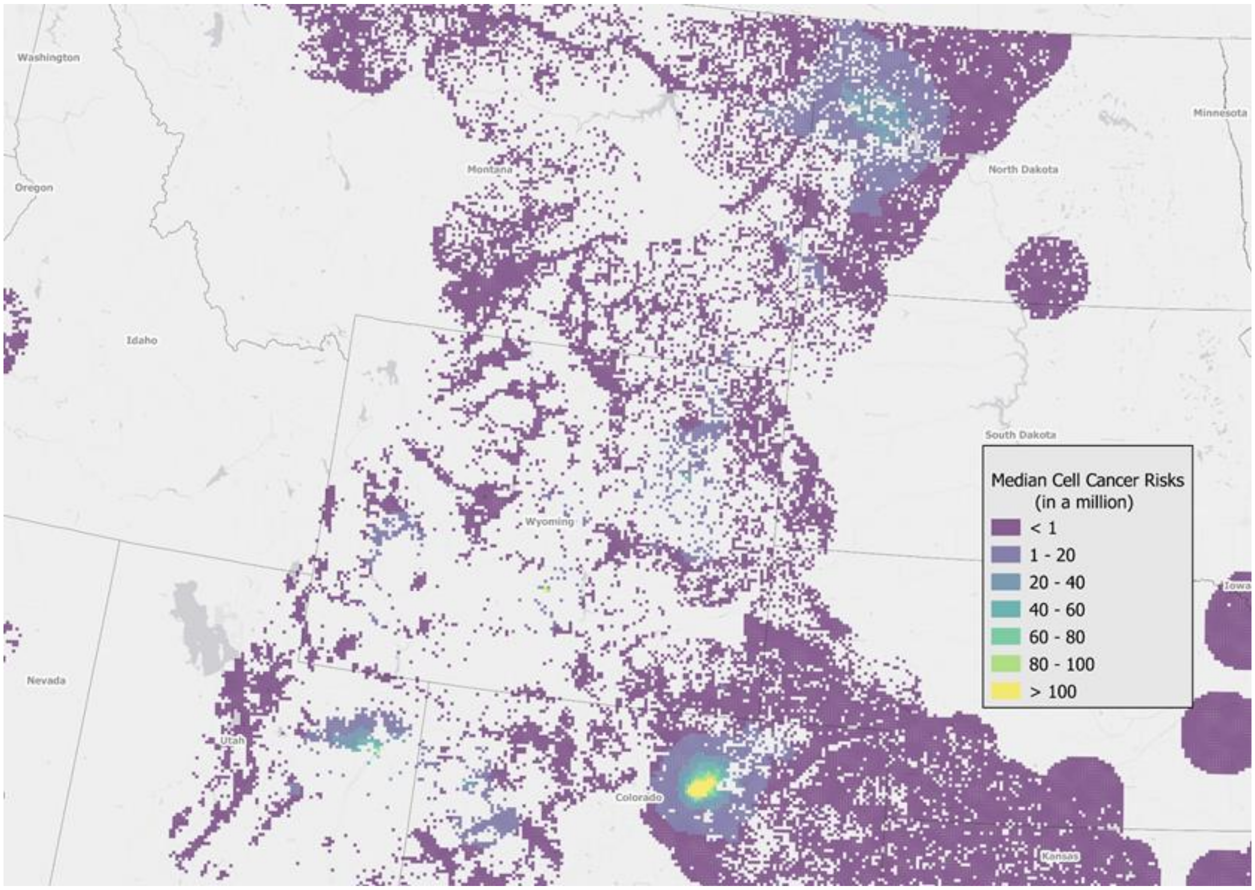

Figure 4-6 Local-Scale Map of Grid Cell Median Cancer Risks for 2017 Nonpoint Oil and Natural Gas NEI Emissions

4.3.5 Demographic Characteristics of Oil and Natural Gas Workers and Communities

The oil and natural gas industry directly employs approximately 140,000 people in oil and natural gas extraction, a figure which varies with market prices and technological change, in addition to many workers in related sectors that provide materials and services. Figure 4-7Figure 4-7 shows employment since 2001.[137] We see a dramatic increase in employment with the rapid expansion in hydraulic fracturing from 2005 to 2014, a decrease after oil prices fell in 2014–2015, and volatility in employment.

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[137] Data was obtained from the Bureau of Labor Statistics Current Employment Statistics program for NAICS code 211.

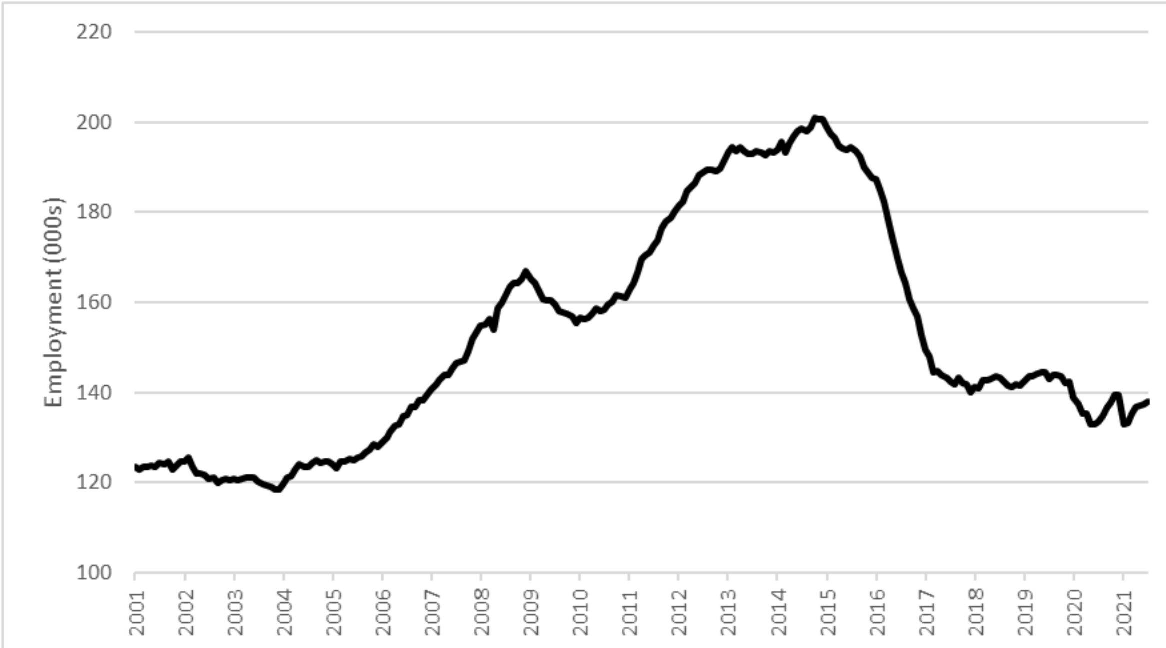

Figure 4-7 National-level Employment in Oil and Natural Gas Production

The EPA also conducted a baseline analysis to characterize potential distributional impacts on employment. A reduction in oil and natural gas activity could have a negative effect on employment among oil and natural gas workers. This could also reduce employment, earnings, and tax revenues in oil and natural gas intensive communities.[138] Any effect on oil and natural gas workers or oil and natural gas intensive locations would be a local and partial equilibrium effect. In general equilibrium, there could be other and potentially offsetting effects in other regions and sectors.

For the distribution of employment effects, we assessed the demographic characteristics of (1) workers in the oil and natural gas sector and (2) people living in oil and natural gas intensive communities. Comparing workers in the oil and natural gas sector to workers in other sectors, oil and natural gas workers may have higher than average incomes, be more likely to have completed high school, and be disproportionately Hispanic. People living in some oil and

[138] For this analysis, oil and natural gas intensive communities are defined as the top 20 percent of communities with respect to the proportion of oil and natural gas workers. Some analyses break the top 20 percent into subgroups which are the 80th–95th percentiles, the 95th–97.5th percentiles, and above the 97.5th percentile by proportion of oil and natural gas workers.

natural gas-intensive communities concentrated in Texas, Oklahoma, and Louisiana, may have disproportionate income levels, rates of high school completion, and demographic composition.

Table 4-14Table 4-14 provides summaries of average income, the percentage of population that is non-Hispanic White, the percentage of population that speaks only English in the home, and the percentage of the population with four years of high school education, all among people with reported income. The table lists these data for the United States, for oil and natural gas workers, for other people, for people in oil and natural gas intensive communities, and for people in other locations. We see that oil and natural gas workers are more highly paid, more likely to be non-Hispanic White individuals, and have higher rates of only speaking English, more likely to have four years of high school, and less likely to be over 50 years old than workers in other sectors. People in oil and natural gas communities are demographically similar to people in other communities. This suggests that, on average, reductions in oil and natural gas drilling or production are unlikely to disproportionately impact marginalized communities either via direct labor channels or spillover channels.

Table 4-14 Demographic Characteristics of Oil and Natural Gas Workers and Communities

	Sectors		Places		Overall
	Oil and Natural Gas Workers	Other People	Oil and Natural Gas Communities	Other Communities	All U.S.
Average Income	$115,000	$44,000	$42,000	$44,000	$44,000
% Non-Hispanic White	81%	71%	68%	69%	71%
% Non-Hispanic Native American	0.97%	0.86%	1.5%	0.56%	0.86%
% English Only	87%	82%	80%	81%	82%
4 years of High School	97%	88%	86%	88%	88%
At Least 50 years old	44%	50%	49%	50%	50%

Note: Calculations based on United States Census Bureau American Community Survey public use microdata from 2015–2019.

This analysis uses 5-year ACS data from 2015-2019 retrieved from IPUMS. This is approximately 16 million individual ACS responses. Oil and natural gas workers are identified by working in industries with a NAICS code that begins with “211.” Those are “Oil and natural gas Extraction,” as well as the sub-industries “Crude Petroleum Extraction” and “Natural Gas Extraction.”

The level of communities is the Public Use Microdata Area (PUMA). PUMAs are districts defined by the United States Census Bureau. PUMA data is procured from IPUMS. They generally have 100,000–200,000 people with an average of about 140,000 people. The average spatial area of a PUMA is 1,692 square miles. We analyze PUMAs because economic spillovers in this sector occur at a multicounty scale. The oil and natural gas sector includes both substantial intercounty commuting and regional supply chains. Additionally, PUMAs are the smallest geographic unit for which detailed individual data are available. In Table 4-14Table 4-14, oil and natural gas communities are defined as the 20 percent of PUMAs with the highest percentage of oil and natural gas workers. Figure 4-8 shows all PUMAs in the continental United States. Oil and natural gas communities as defined in Table 4-14 are highlighted.

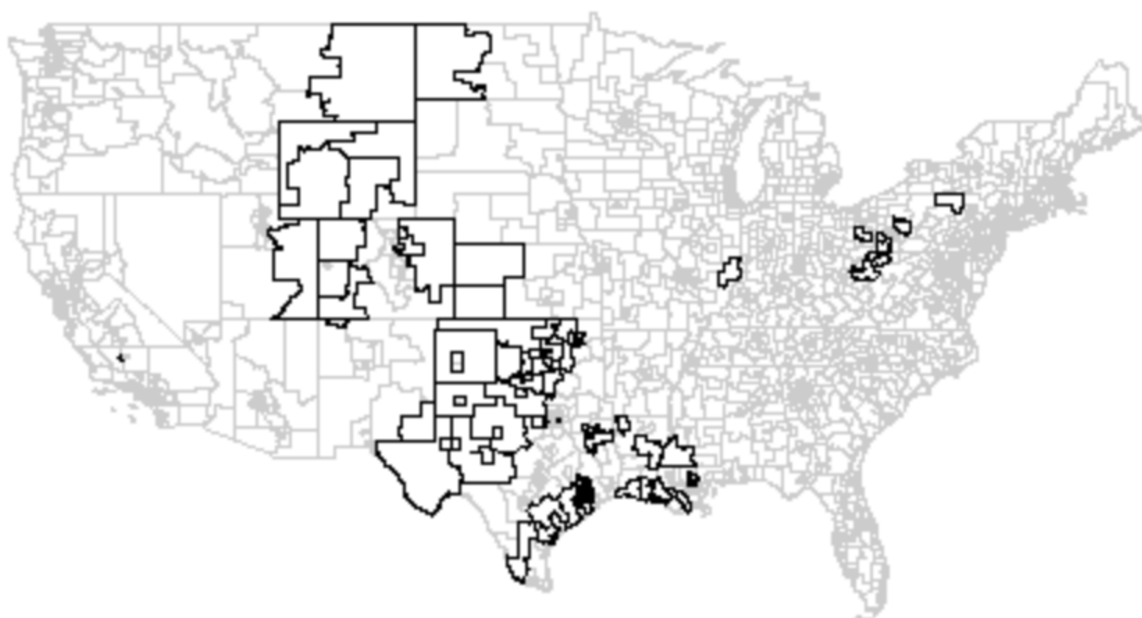

Figure 4-8 Continental U.S. Map of PUMAs and Oil and Natural Gas Intensive Communities

Table 4-15 describes demographics by a region's oil and natural gas (O&G) intensity. Non-oil and natural gas intensive regions (column (1)) are the bottom 80 percent by portion of workers in the oil and natural gas industry. Most of these have no reported oil and natural gas workers. Low oil and natural gas intensive regions (column (2)) are between the 80th and 95th percentiles of oil and natural gas industry employment, high (column (3) are the 95th–97.5th, and very high (column (4)) are above the 97.5th percentile. People in oil and natural gas communities of Table 4-15 are divided between columns (2)–(4). The trimmed comparison group (column (5) is people in non-oil and natural gas intensive regions in states that contain any PUMAs with high or very high intensity. The group of states with high oil and natural gas intensity may be a more appropriate comparison by removing regions of the country which do not resemble oil and natural gas intensive areas, such as the Atlantic coast states.

We see in Block A that people in oil and natural gas intensive communities (columns (2)–(4)) are more likely to be White and Indigenous than people in non-oil and natural gas intensive areas (column (1)). In Block B, we see that people in oil and natural gas-intensive areas' more likely to be Hispanic than people in non-O&G intensive areas. In Block C, we see income, percentage of population with four years of high school education, fraction working in the oil and natural gas industry, and fraction age 50 or older. Comparing people in high and very high oil and natural gas intensity regions (columns (3) and (4)) to people in the trimmed comparison group (column (5)), we see that people in in high oil and natural gas intensity regions are more likely to be White, non-Hispanic, Native American, and less likely to be Asian American or Pacific Islanders.

Table 4-15 Demographic Characteristics of Oil and Natural Gas Communities by Oil and Natural Gas Intensity

Category	Non-O&G Intensive (1)	Low O&G Intensity (2)	High O&G Intensity (3)	Very High O&G Intensity (4)	Trimmed Comparison Group (5)
Block A					
White	77%	81%	84%	78%	73%
Black	10%	8%	8%	7%	8%
Native American	1%	2%	2%	3%	1%
Asian American or Pacific Islander	6%	3%	2%	5%	9%
Other Race	4%	3%	2%	4%	7%
Multiple races	2%	2%	2%	3%	3%
Block B					
Non-Hispanic	88%	84%	86%	81%	80%
Hispanic	12%	16%	14%	19%	20%
Block C					
Income	$44,000	$40,000	$41,000	$47,000	$44,000
Four years of High School	88%	87%	87%	86%	87%
Working in O&G	0.006%	0.1%	0.4%	1%	0.008%
At Least 50 Years Old	50%	50%	50%	47%	48%

Note: Calculations based on United States Census Bureau American Community Survey public use microdata from 2014-2019. Totals may not appear to add correctly due to rounding.

Table 4-16Table 4-16 shows the percentage of people by racial group identification for Hispanics and non-Hispanics, across oil and natural gas intensity. We see that people in high and very high intensity communities are more likely to be Hispanic Whites and non-Hispanic Native Americans, and less likely to be non-Hispanic Asian American and Pacific Islanders than people in non-oil and natural gas intensive communities.

Table 4-16 Hispanic Population by Oil and Natural Gas Intensity

Category	Non-O&G Intensive (1)	Low O&G Intensity (2)	High O&G Intensity (3)	Very High O&G Intensity (4)	Trimmed Comparison Group (5)
Non-Hispanic White	69%	69%	73%	65%	60%
Non-Hispanic Black and African-American	10%	8%	7%	7%	8%
Non-Hispanic Native American	1%	2%	1%	3%	0%
Non-Hispanic Asian American or Pacific Islander	6%	3%	2%	5%	9%
Non-Hispanic Other Race	0%	0%	0%	0%	0%
Non-Hispanic Multiple Races	2%	2%	2%	2%	2%
Hispanic White	8%	12%	11%	14%	12%
Hispanic Black and African-American	0%	0%	0%	0%	0%
Hispanic Native American	0%	0%	0%	0%	0%
Hispanic Asian American or Pacific Islander	0%	0%	0%	0%	0%
Hispanic Other Race	3%	3%	2%	4%	6%
Hispanic Multiple Races	1%	1%	0%	1%	1%

Note: Calculations based on United States Census Bureau American Community Survey public use microdata from 2014-2019. Totals may not appear to add correctly due to rounding.

Marginalized communities are overrepresented in some oil and natural gas intensive communities. Figure 4-9Figure 4-9 highlights oil and natural gas intensive communities with substantial EJ concerns in darker blue. These communities are in the bottom twenty-five percent by income or high-school graduate or non-Hispanic White population percentage. They are concentrated in Texas, Louisiana, and Oklahoma.

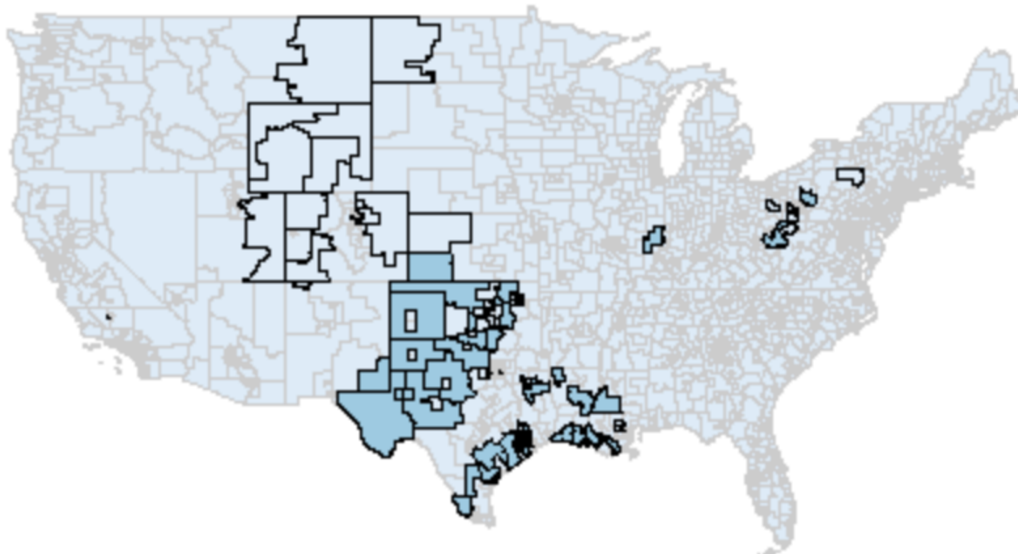

Figure 4-9 Map of Oil and Natural Gas Intensive Communities with Environmental Justice Concerns

4.3.6 Household Energy Expenditures

Energy provides many services to households that are necessary for a basic standard of living. The final regulatory requirements will obligate affected sources to incur costs to reduce emissions, which impact the supply and prices of oil and natural gas and generate energy market impacts, though these impacts are expected to be minimal (see Section 4.1). This section characterizes how household energy expenditures vary across the income distribution and for different racial and ethnic groups. The goal of this section is to highlight which populations and communities may be most vulnerable to potential energy market effects caused by regulatory impacts on the oil and natural gas industry.

Energy insecurity, poverty, and access are important concepts in the discussion of energy burden. Energy insecurity occurs when households lack certainty that they will be able to consume adequate and sufficient energy to meet basic needs. Energy poverty exists when households need to pay disproportionate costs for energy use due to low income, higher energy bills, or inefficient energy use. Energy access barriers exist when households lack access to affordable, reliable energy. Energy insecurity and poverty are persistent problems facing many households across the U.S. (Bednar & Reames, 2020; Kaiser & Pulsipher, 2006; U.S. EIA, 2018) and they have many consequences for human health and wellbeing (Hall, 2013; Jessel et al., 2019; Karpinska & Śmiech, 2020). The EIA found that nearly a third of U.S. households faced challenges paying their energy bills or could not maintain adequate heating or cooling in 2015. For purposes of this section, "energy burden" focuses primarily on energy poverty.

Low-income and minority households tend to face disproportionately high energy burdens (Hernández et al., 2014; Wang et al., 2021) and thus are particularly vulnerable when energy prices increase. Although these households consume less energy, energy tends to represent a larger share of their budgets. (Drehobl et al., 2020) find that low-income, Black, Hispanic, Native American, and older adult households have disproportionally higher energy burdens than the average household. Lyubich (2020) finds that Black households spend more on residential energy than White households even after controlling for income, household size, city, and homeowner status. Wang et al. (2021) find that Black households spent more on energy than other households at every point on the income distribution, suggesting that energy efficiency issues may be more problematic in Black households. They identify geographic location, climate, the characteristics of dwellings, and socioeconomic characteristics as primary drivers of residential energy use and energy burden.

To investigate baseline energy expenditures and potential distributional impacts of possible increases in energy costs, we assessed expenditure and income data stratified by pre-tax income quintiles and race/ethnicity from the 2019 Consumer Expenditure Survey (CES) from the U.S. Bureau of Labor Statistics. We combined expenditures in the following four categories to approximate "energy expenditures": (1) Natural gas, (2) Electricity, (3) Fuel oil and other fuels, and (4) Gasoline, other fuels, and motor oil (transportation). The first three categories are residential energy expenditures, and the fourth category represents transportation energy expenditures. These categories are assumed to potentially experience price impacts due to regulatory costs affecting the oil and natural gas industry, though we expect impacts to be minimal (see Section 4.1).

We examined energy expenditures, the ratio of household energy expenditures to total household expenditures, and the ratio of household energy expenditures to after-tax income across income quintiles and racial groups. It is important to note that energy burden is sensitive to the particular energy services and expenditures are included and how income is defined (e.g., whether transfer payments or taxes are included in income calculation; the inclusion of transportation-related energy expenditures).

Table 4-17Table 4-17 shows energy expenditures by quintiles of pre-tax income. The data indicate that the highest income group consumes the most energy and spends the most per household on it, but energy expenditures represent a smaller percentage of their total expenditures and a much smaller percentage of their income than the lowest income quintile. Energy expenditures as a share of total household expenditures were 8.3 percent for the lowest income quintile and 4.9 percent for the highest income quintile. For energy expenditures as a share of average after-tax income, the distribution is more unequal, ranging from 19.4 percent for the lowest income quintile to 3.4 percent for the highest income quintile. This means the lowest income households are spending over five times more of their income on energy than the highest income households.

Table 4-17 Energy Expenditures by Quintiles of Income before Taxes, 2019

Metric	All	Lowest 20%	Second 20%	Third 20%	Fourth 20%	Highest 20%
Income after taxes	71,487	12,236	32,945	53,123	83,864	174,777
Annual expenditures	63,036	28,672	40,472	53,045	71,173	121,571
Natural gas	416	259	355	367	455	644
Electricity	1,472	1,049	1,351	1,446	1,587	1,924
Fuel oil and other fuels	113	69	101	86	121	189
Gasoline, other fuels, and motor oil (transportation)	2,094	998	1,601	2,079	2,593	3,193
Energy expenditures	4,095	2,375	3,408	3,978	4,756	5,950
Energy expenditures as share of total expenditures	6.5%	8.3%	8.4%	7.5%	6.7%	4.9%
Energy expenditures as share of income	5.7%	19.4%	10.3%	7.5%	5.7%	3.4%
Quintile share of all energy expenditures		11.6%	16.7%	19.4%	23.2%	29.1%

Source: Consumer Expenditure Survey, U.S. Bureau of Labor Statistics, September 2020. https://www.bls.gov/cex/tables/calendar-year/mean-item-share-average-standard-error.htm#cu-income. Accessed 5/27/2021.

Note: Income includes wages, self-employment income, Social Security and retirement payments, interest, dividends, rental income and other property income, public assistance, unemployment and workers' compensation, veterans' benefits, and regular contributions for support.

The EPA also examined the household energy expenditure data by race and ethnicity. The data indicate that Black households' energy expenditures represent a higher share of their total expenditures and income than for households of other races, yet their energy expenditures were lower. Hispanic households' energy expenditures comprise a larger share of their total expenditures and income than non-Hispanic households, though they spent slightly more per household on energy than non-Hispanic households.

The CES data summarized in this section highlight the disproportionately high energy burdens experienced particularly by low-income households, as well as Black and Hispanic households to some extent. These households must allocate a greater share of their incomes and expenditures to energy, reducing disposable income that could be used for other essentials (e.g., housing, healthcare, and food) and other non-essential preferences. Thus, low income, Black, and Hispanic households are expected to be most likely to be adversely affected by any potential increases in energy costs due to this final rule because they face higher energy burdens under the baseline. Nonetheless, since energy cost impacts are expected to be minimal, this rule is not expected to significantly alter existing levels of inequality in energy burden.

4.3.7 Summary

EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis. For this final rulemaking, we quantitatively and qualitatively evaluated the potential for several EJ concerns, although data availability limitations and the large number of oil and natural gas locations make it quite possible that disparities may exist that our analysis did not identify. This is especially relevant for potential EJ characteristics that were not evaluated, such as those living in close proximity to an affected source.

Some commonalities emerged across the array of EJ analyses. Notably, more Hispanic people may reside in communities with potentially elevated cancer risk from oil and natural gas-related toxic emissions (Section 4.3.44.3.4). Similarly, Hispanic populations may be more likely to reside in communities of higher oil and natural gas intensity (Section 4.3.54.3.5). Additionally, Hispanic households' energy expenditures may comprise a disproportionate share of their total expenditures and income as compared to non-Hispanic households (Section 4.3.64.3.6). However, the reductions in ozone concentrations due to the policy option are similar in magnitude across most demographic groups and small such that it is unlikely that the policy option will exacerbate or mitigate any disproportional exposures to ozone that were present at baseline (Section 4.3.3). In some states, those who reside on Tribal land may experience larger reductions in ozone concentrations, but the total magnitude of the change would still be relatively small. Uncertainties associated with the input data, as well as the meaningfulness of any differences, should be taken into consideration when interpreting these results. Additionally, we lack key information that would be needed to characterize post-control risks under the final NSPS OOOOb and EG OOOOc or the regulatory alternatives analyzed in the RIA, preventing the EPA from analyzing spatially differentiated outcomes. Based on the assessment of the impacts of this final rule on minority populations, low-income populations, and/or Indigenous peoples, the EPA believes that this action will achieve substantial methane, VOC, and HAP emissions reductions and will further improve environmental justice community health and welfare.

4.4 Final Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA; 5 U.S.C.§ 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104-121), provides that whenever an agency is required to publish a general notice of final rulemaking, it must prepare and make available an final regulatory flexibility analysis (FRFA), unless it certifies that the final rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. § 605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions. A FRFA describes the economic impact of the final rule on small entities and the steps taken to minimize the significant impact on small entities consistent with the stated objectives of applicable statutes (5 U.S.C. § 604[a]). The scope of the FRFA is limited to the NSPS OOOOb. The impacts of the EG OOOOc are not evaluated here because the EG OOOOc does not place explicit requirements on the regulated industry. Those impacts will be evaluated pursuant to the development of a Federal plan.

4.4.1 Reasons Why Action is Being Considered

The final rulemaking takes a significant step forward in mitigating climate change and The final rulemaking takes a significant step forward in mitigating climate change and improving human health by reducing greenhouse gases (GHG) and volatile organic compounds (VOCs) emissions from the oil and natural gas industry, specifically the Crude Oil and Natural Gas source category. The oil and natural gas industry is the United States' largest industrial emitter of methane. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. According to the Intergovernmental Panel on Climate Change (IPCC), strong, rapid, and sustained methane reductions are critical to reducing near-term disruption of the climate system and a vital complement to carbon dioxide (CO_2) reductions critical in limiting the long-term extent of climate change and its destructive impacts. The oil and natural gas industry also emits other health-harming pollutants in varying concentrations and amounts, including CO_2, VOC, sulfur dioxide (SO_2), nitrogen oxide (NO_X), hydrogen sulfide (H_2S), carbon disulfide (CS_2), and carbonyl sulfide (COS), as well as benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ‘‘BTEX’’), and n-hexane.

The EPA finalizing the actions described in the preamble in accordance with its legal obligations and authorities following a review directed by EO 13990, “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,” issued on January 20, 2021. The EPA intends for the final actions to address the far-reaching harmful consequences and real economic costs of climate change. According to the IPCC, “It is unequivocal that human influence has warmed the atmosphere, ocean and land. Widespread and rapid changes in the atmosphere, ocean, cryosphere and biosphere have occurred.” These changes have led to increases in heat waves and wildfire weather, reductions in air quality, more intense hurricanes and rainfall events, and rising sea level. These changes, along with future projected changes, endanger the physical survival, health, economic well-being, and quality of life of people living in America, especially those in the most vulnerable communities.

In the final action, the EPA has taken a comprehensive analysis of the most attainable data from emission sources in the Crude Oil and Natural Gas source category and the latest available information on control measures and techniques to identify achievable, cost-effective measures to significantly reduce emissions, consistent with the requirements of section 111 of the CAA. The final actions will lead to significant and cost-effective reductions in climate and health-harming pollution and encourage development and deployment of innovative technologies to further reduce pollution in the Crude Oil and Natural Gas source category.

4.4.2 Statement of Objectives and Legal Basis for the Final Rules

The EPA is revising certain NSPS and to promulgate additional NSPS for both methane and VOC emissions from new oil and natural gas sources in the production, processing, transmission and storage segments of the industry; and to promulgate EG to require states to regulate methane emissions from existing sources in those segments. The large amount of methane emissions from the oil and natural gas industry — by far, the largest methane-emitting industry in the nation — coupled with the adverse effects of methane on the global climate compel immediate regulatory action.

The final rule is in line with our 2016 NSPS OOOOa Rule, which likewise regulated methane and VOCs from all three segments of the industry. The 2016 NSPS OOOOa Rule explained that these three segments should be regulated as part of the same source category because they are an interrelated sequence of functions in which pollution is produced from the same types of sources that can be controlled by the same techniques and technologies. That Rule further explained that the large amount of methane emissions, coupled with the adverse effects of GHG air pollution, met the applicable statutory standard for regulating methane emissions from new sources through NSPS. Furthermore, the Rule explained, this regulation of methane emissions from new sources triggered the EPA's authority and obligation to regulate the overwhelming majority of oil and natural gas sources, which the CAA categorizes as "existing" sources. In the 2020 Policy Rule, the Agency reversed course, concluding based upon new legal interpretations that it was not authorized to regulate the transmission and storage segment or to regulate methane. In 2021, Congress adopted a joint resolution to disapprove the EPA's 2020 Policy rule under the CRA. According to the terms of CRA, the 2020 rule is "treated as though [it] had never taken effect," 5 U.S.C. 801(f), and as a result, the 2016 rule is reinstated.

In disapproving the 2020 Policy Rule under the CRA, Congress explicitly rejected the 2020 Policy Rule interpretations and embraced the EPA's rationales for the 2016 NSPS OOOOa Rule. The House Committee on Energy & Commerce emphasized in its report (House Report) that the source category "is the largest industrial emitter of methane in the U.S.," and directed that "regulation of emissions from new and existing oil and gas sources, including those located in the production, processing, and transmission and storage segments, is necessary to protect human health and welfare, including through combatting climate change, and to promote environmental justice." House Report at 3-5. A statement from the Senate cosponsors likewise underscored that "methane is a leading contributing cause of climate change," whose "emissions come from all segments of the Oil and Gas Industry," and stated that "we encourage EPA to strengthen the standards we reinstate and aggressively regulate methane and other pollution emissions from new, modified, and existing sources throughout the production, processing, transmission and storage segments of the Oil and Gas Industry under section 111 of the CAA." Senate Statement at S2283. The Senators concluded with a stark statement: "The welfare of our planet and of our communities depends on it." Id.

The final rule comports with the EPA's CAA section 111 obligation to reduce dangerous pollution and responds to the urgency expressed by the current Congress. With the final rule, the EPA is taking additional steps in the regulation of the Crude Oil and Natural Gas source category to protect human health and the environment. Specifically, the agency is revising NSPS for some sources, adding NSPS for additional sources, and finalizing Emissions Guidelines that would impose a requirement on states to regulate methane emissions from existing sources. As the EPA explained in the 2016 rule, this source category collectively emits massive quantities of the methane emissions that are among those driving the grave and growing threat of climate change, particularly in the near term.[139] Since that time, the science has repeatedly confirmed that climate change is already causing dire health, environmental, and economic impacts in communities across the United States.

Because the 2021 CRA resolution automatically reinstated the 2016 rule, which itself determined that the Crude Oil and Natural Gas Source Category included the transmission and storage segment and that regulation of methane emissions was justified, the EPA is authorized to take the regulatory actions finalized in the rule. In addition, in this action, we are reaffirming those determinations as clearly authorized under any reasonable interpretation of section 111. Further information can be found in Section VIII of the preamble.

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[139] 81 FR 3584

4.4.3 Significant Issues Raised

The only significant issues raised in public comments specifically in response to the initial regulatory flexibility analysis came from the Office of Advocacy within the Small Business Administration (SBA). A summary of those comments and our response is provided in the next section.

4.4.4 Small Business Administration Comments

The SBA's Office of Advocacy (hereafter "Advocacy") provided substantive comments on the IRFA published in the RIA accompanying the November 2021 Proposal. Those comments made the following claims: (1) EPA failed to adequately account for additional burdens of the proposed Appendix K; (2) EPA did not provide burden estimates for the proposed NSPS OOOOb; (3) the IRFA lacked a sufficient discussion of regulatory alternatives that would minimize the impacts on small businesses, and instead merely repeated the SBREFA panel report recommendations as the description of alternatives in the IRFA; and (4) the IRFA did not reflect significant changes to the proposed rule that occurred during and/or after the conclusion of the SBREFA panel. Based on those claims, the Office of Advocacy insisted that EPA issue a revised IRFA that included alternatives reflective of the November 2021 Proposal and December 2022 Supplemental Proposal.

In response to the Advocacy's comments, EPA agreed that issuing a revised IRFA with the December 2022 Supplemental Proposal was warranted, and the revision was published as Section 4.3 in the December 2022 Supplemental Proposal RIA. The revised IRFA addressed Advocacy's critiques of the IRFA contained in the November 2021 Proposal RIA by providing a robust discussion of regulatory alternatives related to provisions for the following elements: fugitive emissions requirements, alternative technologies, associated gas requirements, pneumatic device requirements, and reciprocating compressor requirements. For the final regulatory flexibility analysis, EPA is also including discussion of regulatory alternatives for centrifugal compressor and liquids unloading requirements. Taken together, this discussion addresses Advocacy's concerns about the insufficiency of the discussion of regulatory alternatives in the November 2021 Proposal IRFA. In addition, the revised IRFA noted that the December 2022 Supplemental Proposal did not require OGI in accordance with the proposed

Appendix K for production sites. While equipment leaks at gas plants were still proposed to be monitored using OGI in accordance with Appendix K in the December 2022 Supplemental Proposal, the burden estimates summarized in the revised IRFA reflected burden associated with Appendix K. Finally, the burden estimates were updated to reflect the proposed NSPS OOOOb.

Following the issuance of the December 2022 Supplemental Proposal, Advocacy provided additional comments. While noting that it continued to have significant concerns about the impact the rule would have on small businesses in the oil and gas production sector, Advocacy acknowledged the work that EPA did to improve its RFA compliance through the IRFA between proposals. More detailed responses to Advocacy's comments can be found in Chapter 21 of Volume I of the Response to Comments document.

4.4.5 Description and Estimate of Affected Small Entities

The Regulatory Flexibility Act (RFA) defines small entities as including "small businesses," "small governments," and "small organizations" (5 USC 601). The regulatory revisions being considered by EPA for this rulemaking are expected to affect a variety of small businesses but would not affect any small governments or small organizations. The RFA references the definition of "small business" found in the Small Business Act, which authorizes the Small Business Administration (SBA) to further define "small business" by regulation. The detailed listing of SBA definitions of small business for oil and natural gas industries or sectors, by NAICS code, that are potentially affected by this rule is included in Table 4-18. The EPA conducted this initial regulatory flexibility analysis at the ultimate (i.e., highest) level of ownership, evaluating ultimate parent entities.

Table 4-18 SBA Size Standards by NAICS Code

NAICS Codes	NAICS Industry Description	Size Standards (in millions of dollars)	Size Standards (in no. of employees)
211120	Crude Petroleum Extraction	-	1,250
211130	Natural Gas Extraction	-	1,250
213111	Drilling Oil and Gas Wells	-	1,000
213112	Support Activities for Oil and Gas Operations	$41.5	-
486210	Pipeline Transportation of Natural Gas	$36.5	-

Sources: U.S. Small Business Administration, Table of Standards, Effective July 14, 2022. https://www.sba.gov/document/support--table-size-standards. Accessed July 27, 2022.

To estimate the number of small businesses potentially impacted by the rule, EPA developed a list of operators of oil and natural gas wells, natural gas processing plants, and natural gas compressor stations. The list of well operators is based on data from Enverus and consists of all operators that completed wells producing oil or natural gas in 2019, which serves as an approximation of the universe of operators that might be affected by the NSPS. The list of processing plant operators is from the Department of Homeland Security (DHS) Homeland Infrastructure Foundation-Level Data.[140] The compressor stations operator data is from the Enverus Midstream database. The DHS data and Enverus Midstream data did not contain information on when facilities were constructed, and therefore could not be restricted to only those facilities completed in 2019. The initial list of operators included 1,451 well site operators that completed a well in 2019, 297 processing plant operators, and 574 compressor station operators.

The list of operators was combined with data from the D&B Hoovers and ZoomInfo business databases in a two-step process. D&B Hoovers and ZoomInfo are proprietary, subscription-based databases of business information (such as revenue, employment, and ownership structure) gleaned from sources such as financial statements, news reports, and industry trade group publications. Using an approximate string-matching algorithm, the list of operators was first merged with business information from D&B Hoovers. The remaining unmatched operators were matched to the ZoomInfo business database when possible. This matching process added information on the ultimate parent companies, NAICS codes, number of employees, and annual revenues of the operators. The matches from D&B Hoovers and

[140] Department of Homeland Security. (2020). Homeland Infrastructure Foundation-Level Data. Found at: https://hifld-geoplatform.opendata.arcgis.com/datasets/geoplatform::natural-gas-processing-plants/about.

ZoomInfo were examined and, when necessary, manual adjustments were made to the matched list of ultimate parent companies to standardize company names, revenue, and employment information across the two matched lists. Each matched ultimate parent company, or firm, was classified "small business" or "not small business" based on the SBA size classification threshold associated with the relevant NAICS code. The results of this small business coding exercise are displayed by NAICS code in Table 4-19. In total, 998 of the 1,451 well site operators (69 percent) matched to 914 ultimate parent companies; 270 of 297 processing plant operators (91 percent) matched to 146 ultimate parent companies; and 519 of 574 compressor station operators (90 percent) matched to 315 ultimate parent companies.

Table 4-19 Counts and Estimated Percentages of Small Entities

NAICS Codes	NAICS Industry Description	Number of Firms Identified	Estimated Number of Small Entities	Estimated Percentage of Small Entities for Identified Firms
211120	Crude Petroleum Extraction	333	283	85%
211130	Natural Gas Extraction	22	20	91%
213111	Drilling Oil and Gas Wells	39	37	95%
213112	Support Activities for Oil and Gas Operations	305	265	87%
486210	Pipeline Transportation of Natural Gas	47	14	30%
Many[a]	Other	427	267	63%

[a] Not all owner/operators in the Enverus well database produced a match in the D&B Hoovers database under an oil and natural gas industry-related NAICS as presented in Table 4-18.

4.4.6 Compliance Cost Impact Estimates

To estimate the compliance cost impacts of the final rule on small entities, we use the dataset of operators matched to ultimate parent companies discussed in the previous section and apply the sum of incremental costs for all relevant affected facility categories. Because the incremental costs depend on unknown characteristics of operator-specific well sites, processing plants, and compressor stations, we use average equipment counts at each facility type to derive estimates of average impacts at each facility type. Ultimately, we estimate cost-to-sales ratios (CSR) for each small entity to summarize the impacts of the final NSPS.

4.4.6.1 Methodology for Estimating Impacts on Small Entities

The two main pieces of information we use to assess impacts on small entities are ultimate parent company revenues and expected compliance costs. For most ultimate parent companies in the dataset described in the previous section, revenue is generated from the match with either the D&B Hoovers or ZoomInfo database. For owners of well site operators, we also estimated revenues from calculating total operator-level production in 2019 from Enverus, multiplying by assumed oil and natural gas prices at the wellhead and summing over all operators owned by a parent company. For natural gas prices, we assumed the projected price from AEO2022 in 2022 (adjusted to approximate a wellhead price, as described in Section 2.4) of $3.40/Mcf. For oil prices, we used the projected AEO2022 price for Brent Crude in 2022, $66.40/barrel. Both prices are measured in 2019 dollars. For owners of well site operators, revenue was calculated as the minimum of the matched revenue from D&B Hoovers/ZoomInfo and the estimated revenue based on production. Operators of compressor stations were divided into two groups: those that own gathering and boosting stations, and those that own transmission and storage stations. While there is overlap between the two segments, they are treated as distinct groups in this analysis and results are presented by segment. Summary statistics for firm revenue by segment are presented in Table 4-20.

Table 4-20 Summary Statistics for Revenues of Potentially Affected Entities

Segment	Size	No. of Firms	Mean Revenue (million 2019$)	Median Revenue (million 2019$)
Production	Small	634	$180	$11
	Not Small	67	$21,000	$1,800
Processing	Small	78	$200	$13
	Not Small	60	$28,000	$6,200
Gathering and Boosting	Small	123	$510	$24
	Not Small	77	$19,000	$3,200
Transmission and Storage	Small	50	$260	$22
	Not Small	82	$22,000	$3,200

To calculate expected compliance costs for ultimate parent companies, we first constructed an estimate of the number of sites for each firm in each segment. For well site operators, the number of well sites is calculated by summing the number of well pads containing a well that the operator completed in 2019.[141] The number of well sites owned by an ultimate parent company is calculated by summing over the well site counts of the operators it owns. For processing plants, gathering and boosting compressor stations, and transmission and storage compressor stations, the number of sites for each operator is obtained by summing the number of entries of each type in the DHS data for processing plant operators and in the Enverus Midstream data for compressor station operators. Again, the number of facilities of each type owned by an ultimate parent company is calculated by summing over the facility counts of the processing plant or compressor station operators it owns. Those sums are then multiplied by the ratio of the annual number of new sites we project in each year (see Table 2-3) to the total number of sites we project in 2024 to approximate the number of NSPS OOOOb sites each company might

[141] For a small number of operators, well pad-level identifiers were not available. Those operators were dropped from the analysis.

construct each year. Companies estimated to have fewer than one new site after applying this procedure are assumed to have exactly one new site for the purposes of the analysis.

Once site counts were assigned, we estimated compliance costs for each ultimate parent company by assigning annualized costs (both with and without expected revenue from natural gas recovery) from all relevant affected facilities: fugitive emissions, pneumatic devices, storage vessels, liquids unloading, and associated gas for well sites; equipment leaks, reciprocating compressors, and wet seal centrifugal compressors for processing plants; and reciprocating compressors, wet seal centrifugal compressors, and pneumatic devices for gathering and boosting and transmission and storage compressor stations. Since the precise equipment counts at the facility level were necessary to estimate compliance costs relative to baseline, and this information was not present in the operator data, average costs per facility were used to estimate site-level compliance costs for this analysis. Median per-site capital and annual operating costs for each affected facility are presented in Table 4-21. Median compliance costs by segment and firm size are presented in Table 4-22, both with and without expected revenue from natural gas recovery included.

Table 4-21 Average Capital and Annual Operating Costs by Affected Facility (2019 Dollars)

Segment	Source	Unit	Capital Cost	Annual Operating Cost
Production	Fugitives	Site	-$3	$1,185
	Pneumatics	Site	$16,385	-$251
	Storage Vessels	Battery	$79,352	$22,840
	Associated Gas	Site	$545,611	$1,659
	Liquids Unloading	Event	$0	$65
Gathering and Boosting	Pneumatics	Station	$50,024	$1,977
	Reciprocating Compressors	Compressor	$0	$597
	Wet-Seal Centrifugal Compressors	Compressor	$0	$25,000
Natural Gas Processing	Leaks	Plant	-$15,255	-$28,913
	Reciprocating Compressors	Compressor	$0	$597
Transmission	Pneumatics	Station	$61,329	$360
	Reciprocating Compressors	Compressor	$0	$597
Storage	Pneumatics	Station	$96,269	-$2,210
	Reciprocating Compressors	Compressor	$0	$597

Table 4-22 Distribution of Estimated Compliance Costs across Segment and Firm Size Classes (2019$)

Segment	Size	No. of Firms	Average Cost without Product Recovery	Average Cost with Product Recovery
Production	Small	634	$26,000	$17,000
	Not Small	67	$48,000	$4,500
Processing	Small	78	-$28,000	-$34,000
	Not Small	60	-$29,000	-$35,000
Gathering and Boosting	Small	123	$12,000	$6,800
	Not Small	77	$24,000	$14,000
Transmission and Storage	Small	50	$11,000	$8,500
	Not Small	82	$11,000	$8,500

Note: Totals may not appear to add correctly due to rounding.

4.4.6.2 Results

This section presents results of the cost-to-sales ratio analysis for the production, processing, gathering and boosting, and transmission and storage segments. The cost-to-sales ratios presented approximate the impact of the NSPS requirements on ultimate parent companies of well site, processing plant, and compressor station operators. In the processing segment, average annualized costs relative to baseline are expected to be negative, and no entity has a CSR greater than either 1 percent or 3 percent.[142] In the production segment, when expected revenues from natural gas product recovery are included, 200 small entities (31 percent) have cost-to-sales ratios greater than 1 percent, and of those, 59 have cost-to-sales ratios greater than 3 percent (9 percent). When expected revenues from natural gas product recovery are excluded, the number of small entities with cost-to-sales ratios greater than 1 percent increases to 210 (33 percent); 62 of those small entities (10 percent) also have cost-to-sales ratios greater than 3 percent. In the gathering and boosting segment, no parent companies have cost-to-sales ratios greater than 3 percent regardless of whether expected revenues from natural gas recovery are included. Seven parent companies (6 percent) have a cost-to-sales ratio greater than 1 percent when expected revenues from natural gas recovery are excluded (only one does when they are included). In the transmission and storage segment, only one entity has a CSR greater than 1 percent, and only if

[142] The net compliance costs for leak detection at natural gas processing plants decrease primarily because OGI surveys under this proposal can be conducted much more quickly and at approximately half the cost of EPA Method 21 surveys under the current requirements in NSPS VVa, so the increased flexibility under the proposal is likely cost saving for affected facilities.

expected revenues from product recovery are included. The results for all segments are summarized in Table 4-23.

Table 4-23 Compliance Cost-to-Sales Ratios for Small Entities

Segment	CSR Ratio Category	Without Product Recovery Included		With Product Recovery Included	
		No. of Small Entities	*% of Small Entities*	*No. of Small Entities*	*% of Small Entities*
Production	All	634		634	
	Greater than 1%	148	23%	141	22%
	Greater than 3%	62	10%	59	9%
Processing	All	78		78	
	Greater than 1%	0	0%	0	0%
	Greater than 3%	0	0%	0	0%
Gathering and Boosting	All	123		123	
	Greater than 1%	7	6%	1	1%
	Greater than 3%	0	0%	0	0%
Transmission and Storage	All	50		50	
	Greater than 1%	1	2%	0	0%
	Greater than 3%	0	0%	0	0%

4.4.7 Caveats and Limitations

The analysis above is subject to several caveats and limitations, many of which we discussed in the presentation of methods and results. It is useful, however, to present a compiled list of the caveats and limitation here.

- Not all owner/operators could be identified in either the D&B Hoovers or ZoomInfo database. In addition, the matching procedure used to link the operator database to the D&B Hoovers and ZoomInfo database is imperfect, so there may be misspecified matches or duplicate entries for the same entity.

- The analysis assumes the same population of entities completing wells in 2019 are also completing wells at the same rate in 2024 and beyond and assumes facility counts are stable over time. These firms may operate more or fewer facilities in the future depending on economic and technological factors that are largely unpredictable. The analysis also assumes the population of entities operating processing plants and compressor stations in 2019 is the same population that will construct new processing plant and compressor stations in 2024 and beyond.

- The approach used to estimate sales for the cost-to-sales ratios might over-estimate or under-estimate sales depending upon the accuracy of the information in the underlying databases and the market prices ultimately faced when the final requirements are in effect.
- It is unknown what equipment is present at each site. The use of cost averages to estimate costs may under- or over-estimate costs at the site level for any given entity, which adds uncertainty to the calculated cost-to-sales ratios.

4.4.8 Projected Reporting, Recordkeeping and Other Compliance Requirements

The information to be collected for the final NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents under subpart OOOOb are owners or operators of new, modified, or reconstructed oil and natural gas affected facilities as defined under the rule. Few, if any, of the facilities in the United States are owned or operated by state, local, tribal or the Federal government. The regulated facilities are privately owned for-profit businesses. The requirements in this action result in industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and train personnel to be able to respond to the collection of information.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOb for the estimated 1,849 owners and operators that are subject to the rule is approximately 883,625 labor hours, with an annual average cost of about $58 million. The annual public reporting and recordkeeping burden for this collection of information is estimated to average about 60 hours per respondent. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

4.4.9 Related Federal Rules

There are two National Emission Standards for Hazardous Air Pollutants (NESHAP) rules that apply to certain equipment and processes in the oil and natural gas sector. These rules, listed below, address air toxics, primarily benzene, toluene, ethylbenzene, and xylenes (collectively referred to as BTEX) and n-hexane. These two rules were promulgated under section 112 of the Clean Air Act and are codified in 40 CFR Part 63 Subpart HH and Subpart HHH.

Aside from the EPA, several other Federal agencies have jurisdiction over the oil and natural gas sector.

- The Bureau of Land Management (BLM) within the Department of the Interior regulates the extraction of oil and natural gas from federal lands. BLM manages the Federal government’s onshore subsurface mineral estate, about 700 million acres. BLM also oversees oil and natural gas operations on many Tribal leases and maintains an oil and natural gas leasing program. BLM does not directly regulate emissions for the purposes of air quality but does regulate venting and flaring of natural gas for the purposes of preventing waste. An operator may also be required to control/mitigate emissions as a condition of approval on a drilling permit.
- The Bureau of Ocean Energy Management (BOEM) within the Department of the Interior manages the development of America’s offshore energy and mineral resources. BOEM has certain air quality regulatory authority over activities that BOEM authorizes on the Outer Continental Shelf of the United States in the Gulf of

Mexico, west of 87.5 degrees longitude, and adjacent to the North Slope Bureau of the State of Alaska.

- The Pipeline and Hazardous Materials Safety Administration (PHMSA) within the Department of Transportation ensures safety in the design, construction, operation, maintenance, and spill response planning of America's 2.8 million miles of natural gas and hazardous liquid transportation pipelines. This includes data and risk analysis, outreach, research and development, regulations and standards, training, inspections and enforcement and accident investigations. Section 113 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020) mandates that PHMSA promulgate a final rule concerning gas pipeline leak detection and repair programs no later than one year after the enactment of the law.
- The Federal Energy Regulatory Commission (FERC) within the Department of Energy (DOE) regulates natural gas pipeline, storage, and liquefied natural gas facility construction. FERC also issues environmental assessments or draft and final environmental impact statement for comment on most projects.
- The Internal Revenue Service (IRS), in the Internal Revenue Code (IRC), defines a stripper well property as "a property where the average daily production of domestic crude oil and natural gas produced from the wells on the property during a calendar year divided by the number of such wells is 15 barrel equivalents or less." See IRC 613A(c)(6)(E).

4.4.10 Regulatory Flexibility Alternatives

Prior to the November 2021 Proposal, the EPA convened a Small Business Advocacy Review (SBAR) Panel to obtain recommendations from small entity representatives (SERs) on elements of the regulation. The Panel identified significant alternatives for consideration by the Administrator of the EPA, which were summarized in a final report.[143] Based on the Panel recommendations, as well as comments received in response to the November 2021 Proposal and

[143] See document ID EPA-HQ-OAR-2021-0317-0074.

December 2022 Supplemental Proposal, the EPA is finalizing several regulatory alternatives that could accomplish the stated objectives of the Clean Air Act while minimizing any significant economic impact of the final rule on small entities. Discussion of those alternatives is provided below.

4.4.10.1 Fugitive Emissions Requirements

As described in the preamble to the to the final rule,[144] the EPA is finalizing certain changes, proposed in the December 2022 Supplemental Proposal,[145] to the fugitive emissions standards proposed in November 2021 for NSPS OOOOb. The EPA believes that two of these finalized changes will reduce impacts on small businesses: (1) requiring OGI monitoring for well sites and centralized production facilities following the monitoring plan required in 40 CFR 60.5397b instead of requiring the procedures proposed in Appendix K for these sites and (2) defining monitoring technique and frequency based on the equipment present at a well site. The EPA describes these two changes below.

In the final rule, the EPA is not requiring OGI monitoring in accordance with the proposed Appendix K for well sites or centralized production facilities, as was proposed in the November 2021 proposal. Instead, the EPA is requiring OGI surveys following the procedures specified in the regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21. This change is consistent with the requirements for OGI surveys found in NSPS OOOOa at 40 CFR 60.5397a. This final change is a result of the extensive comments the EPA received from oil and natural gas operators and other groups on the numerous complexities associated with following the proposed Appendix K, especially considering the remoteness and size of many of these well sites.[146] In addition, commenters pointed out that OGI has always been the BSER for fugitive monitoring at well sites and was never designed as a replacement for EPA Method 21, while Appendix K was designed for use at more complex processing facilities that have historically been subject to monitoring following EPA Method 21. The EPA agrees with the commenters and is final requirements within NSPS OOOOb at 40 CFR 60.5397b in lieu of the

[144] See final rule preamble Section XI.A.
[145] See December 2022 Supplemental Proposal preamble Section IV.A.
[146] See final rule preamble Section XI.A. and see Document ID Nos. EPA-HQ-OAR-2021-0317-0579, -0743, -0764, -0777, -0782, -0786, -0793, -0802, -0807, -0808, -0810, -0814, -0817, -0820, -0831, -0834, and -0938.

procedures in Appendix K for fugitive emissions monitoring at well sites or centralized production facilities. See section X.I.V of the preamble for additional information on what the EPA is finalizing for Appendix K related to other sources (e.g., natural gas processing plants). The EPA believes this will particularly benefit small entities because it will streamline the requirements for conducting and documenting OGI surveys at these smaller, less complex sites. Additionally, this change provides a uniform set of requirements for regulated entities that may have assets subject to different subparts within the same region, which leads to increased regulatory certainty and eases the compliance burden. At the same time, the EPA believes this does not compromise the stated objectives of the Clean Air Act because these same requirements are already allowed in NSPS OOOOa and outline many of the same data elements required by Appendix K.

Next, the final rule includes fugitive monitoring frequencies and detection techniques that are based on the type of equipment located at a well site, instead of the baseline methane emissions threshold that was included in the November 2021 Proposal. Specifically, the EPA is finalizing four distinct subcategories of well sites:

- Well sites with only a single wellhead,
- Small well sites with a single wellhead and only one piece of major production and processing equipment,[147]
- Well sites with only two or more wellheads and no other major production and processing equipment, and
- Well sites or centralized production facilities with one or more controlled storage vessels, control devices, natural gas-driven pneumatic controllers or pumps, or two or more other major production and processing equipment.

[147] Small well sites are defined as single wellhead well sites that do not contain any controlled storage vessels, control devices, pneumatic controller affected facilities, or pneumatic pump affected facilities, and include only one other piece of major production and processing equipment. Major production and processing equipment that would be allowed at a small well site would include a single separator, glycol dehydrator, centrifugal and reciprocating compressor, heater/treater, and storage vessel that is not controlled. By this definition, a small well site could only potentially contain a well affected facility (for well completion operations or gas well liquids unloading operations that do not utilize a CVS to route emissions to a control device) and a fugitive emissions components affected facility. No other affected facilities, including those utilizing CVS (such as pneumatic pumps routing to control) can be present for a well site to meet the definition of a small well site.

The EPA is finalizing these distinct subcategories of well sites after consideration of comments on the November 2021 Proposal that stated the original baseline methane emissions threshold approach would be difficult to implement, especially for small businesses that may be less familiar with the use of emissions factors from the EPA's Greenhouse Gas Reporting Program. The EPA believes that owners and operators, including small entities, can readily identify the number and types of major equipment located at a well site without the need for complicated calculations of emissions.

Further, the EPA is finalizing specific monitoring frequencies and techniques as the BSER for each well site subcategory individually. For example, the EPA is finalizing the use of audible, visual, and olfactory (AVO) inspections at well sites containing only a single wellhead and at small well sites. This monitoring technique does not require specialized equipment or operator training, but does allow the identification of large leaks, which are of the most concern from an environmental standpoint. Further, AVO monitoring can easily be built into regular maintenance activities that are designed to keep the equipment at the site in good working order. The final requirements are responsive to a SER recommendation that the EPA allow AVO and soap bubble tests as an option for finding fugitive emissions, particularly because they are low cost and easy to implement alternatives for detecting leaks, and an Advocacy recommendation that the EPA allow AVO as an alternative in limited circumstances, such as part of an off-ramp for facilities unlikely to emit more than insignificant methane or with a demonstrated history of insignificant emissions. The EPA believes this will particularly benefit small entities because AVO surveys at these types of well sites are effective at identifying the types of large emissions from sources located at these well sites at a much lower cost than OGI surveys. For example, the costs associated with the quarterly AVO inspections are estimated at $660/year, whereas the costs associated with an annual OGI survey for this type of well site are estimated at approximately $2,000/yr. Inspections via AVO allow for more frequent inspections for large emissions events at these well sites, which results in faster emissions mitigation, than a single OGI survey each year.

4.4.10.2 Alternative Technology

As described in the preamble to the December 2022 Supplemental Proposal,[148] the EPA is finalizing changes to the November 2021 alternative technology requirements for NSPS OOOOb. The changes are the result of overwhelming support that the EPA received for the inclusion of an option to use advanced technologies for periodic screenings as an alternative to the fugitive emissions monitoring and repair program in NSPS OOOOb. The EPA believes these changes will reduce impacts on small businesses.

Specifically, the EPA is finalizing the use of alternative screening technologies as a compliance option rather than an additional regulatory requirement. Through the SBAR Panel outreach, SERs supported the use of aerial, satellite, and other forms of monitoring for fugitive emissions requirements beyond traditional fugitive emissions monitoring and repair, but only as an alternative and not as an additional requirement. In addition, the Panel recommended that the EPA consider the cost and scope of alternative technologies and alternative screening technology, and that the EPA try to minimize significant additional reporting and recordkeeping requirements. In accordance with these recommendations, the EPA is finalizing changes that are intended to support and incentivize the deployment and utilization of a broader spectrum of advanced measurement technologies and, ultimately, enable more cost-effective reductions in emissions. These changes include a "matrix" which would specify several different screening frequencies corresponding to a range of minimum detection levels, in contrast to the single screening frequency and detection level permitted under the November 2021 Proposal. In addition, the EPA will allow owners and operators the option of using continuous monitoring technologies as an alternative to periodic screening in conjunction with long- and short-term emissions rate thresholds that would trigger investigation as well as monitoring plan requirements for owners and operators that choose this approach. Entities interested in using an alternative methane detection technology to comply with the rule must submit a request for alternative test method approval to EPA. The EPA believes this approach will particularly benefit small entities because they will be allowed flexibility to determine which screening technology works best for their needs without the need to undertake the application of an

[148] See preamble section XI.B.

alternative means of emissions limitation (AMEL), which would be especially burdensome for small entities with less ability to perform extensive field testing of technologies or conduct sophisticated modeling simulations. Furthermore, this approach incorporates the use of alternative test methods, which allows for broad application of technologies after approval, without the need for individual applications from owners and operators for their specific sites.

4.4.10.3 Associated Gas

As described in the final rule,[149] the EPA is finalizing certain changes to the requirements for oil wells with associated gas that were proposed in November 2021 for NSPS OOOOb and revised in the supplemental proposal of December 2022. These changes include adjustments to the hierarchy of the standard and compliance options. The EPA believes these final changes will increase the burden on some small businesses and reduce impacts on other small businesses.

Specifically, the EPA is requiring flaring of all associated gas from existing, modified, and reconstructed wells where a determination has been made that it is not feasible to route the associated gas to a sales line or use it for another beneficial purpose due to technical or safety reasons. This demonstration would need to not only address the lack of availability or access to a sales line but would also need to demonstrate why all potential beneficial uses are not feasible due to technical or safety reasons. This demonstration, which would require certification by a professional engineer or other qualified individual, would be submitted in the first annual report for the well affected facility. The EPA is has described what this demonstration should entail and what qualifications constitute an “other qualified individual” in the preamble for this final action.

Second, the EPA has subcategorized wells by the level of production above and below 10 tons per year of methane, and reduced the administrative burden for those sources below 10 tons per year, by allowing that associated gas be directed to a flare without a demonstration that routing the gas to a sales line, using the gas for another useful purpose, reinjecting the gas into the subsurface, or using the gas for an onsite fuel source are each and all infeasible. The EPA believes this approach will benefit small entities because it allows for the flaring of associated gas when the amount of gas to be handled is unlikely to be used or disposed cost effectively in

[149] See preamble section XI.F.

another way. Installation of a sales pipeline or other infrastructure necessary to use associated gas in a beneficial way is very costly, especially where well sites are located at great distances from other necessary infrastructure, such as natural gas processing plants. These costs can disproportionally affect small businesses who may not produce a large enough quantity of associated gas to offset the capital necessary to install such infrastructure. The allowance of flaring in these situations without a technical demonstration of infeasibility for another use or disposal of the gas provides for a way to reduce emissions of methane to the atmosphere (in contrast to direct venting of associated gas), but at a lower cost than the cost for new infrastructure.

4.4.10.4 Pneumatic Controller and Pneumatic Pump Requirements

As described in the preamble to the final rule,[150] the EPA is finalizing certain clarifications and changes to the pneumatic controller and pneumatic pumps emissions requirements included in the November 2021 Proposal and revised in the December 2022 Supplemental Proposal

Through the SBAR Panel outreach, SERs stated that zero emission controllers are not feasible at wells sites or other locations without reliable electricity, installing gas-fired compressors to provide sufficient air for instrument air systems may defeat the purpose by ultimately increasing emissions, and the installation of electric service would be extremely expensive. The EPA and Advocacy recommended that the EPA only propose zero emission standards for process controllers at sites with reliable and consistent onsite power available and clearly state that the intent is not to require the installation of electric services for this purpose.[151]

For process controllers, the EPA maintains that there is a technically feasible option available for zero-emitting controllers for all production, processing, and transmission and storage sites, except for sites in Alaska without access to electricity. The EPA further identifies compliance options for process controllers other than using electricity. Therefore, the final NSPS OOOOb does not include any alternative non-zero emission standards for process controllers, except at sites in Alaska without access to electrical power. At those Alaskan sites,

[150] See preamble Sections XI.D and XI.E.

owners/operators may use low-emitting process controllers or route emissions to a control device achieving a 95 percent reduction in emissions.

For pumps, the final rule recognizes that at sites without access to electricity, there could be situations where it is technically infeasible to use zero-emitting pumps. As a result, the EPA is finalizing a tiered structure in the rule that provides flexibility based on site-specific conditions. At sites without access to electricity and that have fewer than three diaphragm pumps, owners/operators may route emissions to a process through an onsite vapor recovery unit (VRU), or if a VRU is not onsite, they may route emissions to a control device already onsite. If there is no control device onsite, control of emissions from the pumps affected facility is not required.

The final requirements are responsive to SER's statements and concerns about technical feasibility and have considered the potential impacts and feasibility challenges for small businesses.

4.4.10.5 Reciprocating Compressors

In the November 2021 Proposal, the EPA proposed that an owner or operator of a reciprocating compressor affected facility would be required to monitor the rod packing emissions annually by conducting flow rate measurements. When the measured flow rate exceeded 2 scfm (in pressurized mode), replacement of the rod packing would have been required. Alternatively, the November 2021 Proposal would have also provided owners and operators the option of routing rod packing emissions to a process via a closed vent system under negative pressure in order to comply with the rule. The proposed option to route to a process would have been allowed as an alternative under NSPS OOOOb because implementing this option, where feasible, would achieve greater emission reductions than the proposed performance-based emissions threshold standard. The December 2022 Supplemental Proposal proposed changes and specific clarifications to the November 2021 Proposal standards for NSPS OOOOb. For the proposed replacement of the rod packing based on an emission limit and annual measurement requirement, we proposed: (1) To clarify that the standard of performance is a numeric standard (not a work practice standard) of 2 scfm, (2) to allow for repair (in addition to replacement) of the rod packing in order to maintain an emission rate at or below 2 scfm, and (3) to allow for monitoring based on 8,760 hours of operation instead of based on a calendar year. The EPA also proposed regulatory text that defined the required flow rate measurement methods and/or procedure requirements, and recordkeeping and reporting requirements. For the alternative option of routing rod packing emissions to a process via a closed vent system under negative pressure, the EPA proposed to remove the negative pressure requirement.

As described in the preamble to the final rule,[152] the EPA is finalizing changes to the proposed requirements for reciprocating compressors in for NSPS OOOOb as a result of comments received on the November 2021 Proposal and December 2022 Supplemental Proposal. The EPA believes the following rule changes will reduce impacts on small businesses.

Concerns were expressed regarding the EPA's November 2021 Proposal and December 2022 Supplemental Proposal that shifted rod packing changeout requirements from a designated schedule of once every 3 years to a performance standard based on an annual flow rate measurement. While the November 2021 Proposal format of the performance standard based on volumetric flow rate measurements was as a work practice standard, the December 2022 Supplemental Proposal format of the performance standard was as a numeric standard. Commenters on the December 2022 Supplemental Proposal expressed that, as a numeric standard, the performance standard based on flow measurements was unworkable. It was also noted that a performance standard is often more expensive than a fixed equipment change-out standard because of the additional monitoring and recordkeeping necessary to demonstrate compliance with the performance standard, which they believed could negatively impact small businesses. These commenters also supported the fixed schedule rod packing change-out standard because this is the standard owners and operators have implemented for reciprocating compressors under NSPS OOOOa and stated that the annual flow rate performance work practice standard would lead to more rod packing changeouts than would be required based on the November OOOOa fixed-schedule packing change out requirements.

The EPA is finalizing the following requirement changes associated with the reciprocating compressor rod packing volumetric flow rate measurement performance standard based on November 2021 Proposal and December 2022 Supplemental Proposal comments: (1) a

[152] See final rule preamble Section XI.I.

2 scfm volumetric flow rate per cylinder performance work practice standard, (2) repair (in addition to replacement) of the rod packing is allowed to maintain an emission rate at or below 2 scfm per cylinder; and (3) monitoring based on 8,760 hours of operation instead of based on a calendar year. These final requirements for reciprocating compressors are responsive to comments and concerns expressed by industry (including small businesses).

The EPA believes the final rule 2 scfm volumetric flow rate per cylinder performance work practice standard approach benefits small entities because facilities can use monitoring data to determine emission levels at which it is necessary to repair or replace rod packing. This approach can result in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term cost savings. Allowing an owner or operator to repair the rod packing (in addition to replacement of the rod packing) to maintain an emission rate at or below 2 scfm per cylinder alleviates the need to replace the rod packing when only a simple repair may be needed to maintain volumetric flow rate at or below 2 scfm per cylinder. Requiring owners and operators to conduct volumetric flow rate monitoring based on 8,760 hours of operation instead of based on a calendar year reduces the burden on owners and operators where compressors are not operational for multiple months or are used intermittently. Additionally, by requiring that monitoring frequency based on hours of operation, owners and operators have the flexibility to stagger maintenance activity throughout the year. The final rule defines the required flow rate measurement methods and/or procedures, repair and replacement requirements, and recordkeeping and reporting requirements.

In addition, the following regulatory options have been added to the final rule: (1) owners and operators are allowed to change out reciprocating compressor rod packing every 8,760 hours of operation in lieu of conducting volumetric flow rate monitoring every 8,760 hours; and (2) owners and operators are allowed to route emissions to a control device via a closed vent system in addition to routing emissions via a closed vent system to a process. For the alternative option of routing rod packing emissions to a process via a closed vent system under negative pressure, the EPA is finalizing the removal of the negative pressure requirement. By allowing owners and operators to change out rod packing every 8,760 hours of operation in lieu of conducting volumetric flow rate monitoring every 8,760 hours, owners and operators have the option to choose a more-stringent rod packing change out schedule (on or before every 8,760 hours of operation) and avoid the need to conduct volumetric flow rate monitoring. Lastly, by the final rule allowing owners and operators to route emissions to a control device in addition to routing emissions to a process, the EPA has added flexibility to the compliance options available for owners and operators.

4.4.10.6 Centrifugal Compressors

For the NSPS OOOOb, the December 2022 Supplemental Proposal required that centrifugal compressor affected facilities with wet seals comply with the GHG and VOC standards by reducing methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent. As an alternative to routing the closed vent system to a control device, an owner or operator was provided the option to route the closed vent system to a process or utilize a self- contained wet seal centrifugal compressor. If an owner or operator chooses to comply with this requirement either by using a control device to reduce emissions or by routing to a process to reduce emissions, an owner was required to equip the wet seal fluid degassing system with a cover and the cover must be connected through a closed vent system meeting specified requirements, such as design and operation with no identifiable emissions.

For owners or operators of self-contained wet seal centrifugal compressors or centrifugal compressors equipped with dry seals, the EPA proposed that owners or operators comply with the GHG and VOC standards by reducing methane and VOC emissions by ensuring a volumetric flow rate at or below 3 scfm. In addition to the flow rate monitoring being required every 8,760 hours of operation.

As described in the preamble to the final rule,[153] the EPA is finalizing changes to the proposed requirements for centrifugal compressors in for NSPS OOOOb as a result of comments received on the November 2021 Proposal and December 2022 Supplemental Proposal. The EPA believes the following rule changes associated with the centrifugal compressor volumetric flow rate measurement performance standards will reduce impacts on small businesses: (1) volumetric flow rate per seal standards of performance finalized as work practice standards (not as numeric standards), (2) a 3 scfm volumetric flow rate per seal performance work practice standard for self-contained wet seal centrifugal compressors (including centrifugal compressors equipped

[153] See section XI.G of the final rule preamble.

with mechanical seals), (3) a 10 scfm volumetric flow rate per seal performance work practice standard for dry seal compressors, (4) a 9 scfm volumetric flow rate per seal performance work practice standard for Alaska North Slope centrifugal compressors equipped with sour seal oil separator and capture system, and (5) monitoring based on 8,760 hours of operation instead of based on a calendar year.

The EPA believes the final rule volumetric flow rate per seal performance work practice standard approach for self-contained wet seal centrifugal compressors, Alaska North Slope centrifugal compressors equipped with sour seal oil separator and capture system, and centrifugal compressors equipped with dry seals benefits small entities because facilities can use monitoring data to determine if repair of a seal is necessary. For self-contained wet seal centrifugal compressors (including centrifugal compressors equipped with mechanical seals) and Alaska North Slope centrifugal compressors equipped with sour seal oil separator and capture system, small entities benefit by allowing owners and operators to meet the work practice standards in lieu of requiring that they reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent. By tailoring the final rule volumetric flow rate per seal performance work practice standards for self-contained wet seal centrifugal compressors and Alaska North Slope centrifugal compressors equipped with sour seal oil separator and capture system, EPA is addressing industry concerns (including small business concerns) that it would be cost-ineffective for these low-emitting wet seal centrifugal compressors to reduce emissions from wet seal fluid degassing system by 95 percent. By raising the final rule volumetric flow rate per seal performance work practice standard for centrifugal compressors equipped with dry seals from 3 scfm to 10 scfm per seal, EPA is addressing industry concerns (including small business concerns) that a 3 scfm per seal standard is not supported and a 10 scfm volumetric flow rate standard represents a maximum volumetric flow rate standard that is applicable to all dry seals based on manufacturer information.

Requiring owners and operators to conduct volumetric flow rate monitoring based on 8,760 hours of operation instead of based on a calendar year reduces the burden on owners and operators where compressors are not operational for multiple months or are used intermittently. Additionally, by requiring that monitoring frequency based on hours of operation, owners and operators have the flexibility to stagger maintenance activity throughout the year. The final rule defines the required flow rate measurement methods and/or procedures, repair requirements, and recordkeeping and reporting requirements.

4.4.10.7 Liquid Unloading Operations

In the December 2022 Supplemental Proposal, the EPA proposed regulatory text where all gas well liquids unloading operations would be subject to the regulatory requirements. The BSER proposed was to employ techniques or technologies that eliminate methane and VOC emissions. Where it was technically infeasible or not safe to meet the zero emissions standard, the EPA proposed to require the employment of best management practices to minimize methane and VOC emissions during well liquids unloading operations to the maximum extent possible. The December 2022 Supplemental Proposal specifically requested further comment and any additional information regarding whether would only apply to well affected facilities that undergo well liquids unloading that result in vented emissions.

In addition, the December 2022 Supplemental Proposal specified recordkeeping and reporting requirements related to well liquids unloading operations. Wells that utilized a non-venting method would have been required to maintain records of the number of well liquids unloading operations that occur within the reporting period and the method(s) used for each well liquids unloading operation. A summary of this information would also have been required to be reported in the annual report. In recognition that under some circumstances, venting could occur when a selected liquids unloading method that is designed to not vent to the atmosphere is not properly applied (e.g., a technology malfunction or operator error). Under the proposed rule, owners and operators in this situation would have been required to record and report these instances, as well as document and report the length of venting and what actions were taken to minimize venting to the maximum extent possible. Additionally, for wells that utilize methods that vent to the atmosphere, the proposed rule would have required: (1) Documentation explaining why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons; (2) development of best management practices that ensure that emissions during liquids unloading are minimized; (3) employment of the best management practices during each well liquids unloading operation and maintenance of records demonstrating that the best management practices were followed; (4) reporting in the annual report both the number of well liquids unloading operations and any instances where the well liquids unloading operations did not follow the best management practices.

As described in the preamble to the final rule,[154] the EPA is finalizing certain changes to the proposed requirements for gas well liquids unloading operations in the final rule. The EPA believes these changes will reduce impacts on small businesses.

Several commenters opposed the EPA's proposed zero-emission standard or asserted that the EPA should only regulate unloading operations that vent emissions. Another commenter expressed that BSER must be technically feasible for the source category. The commenter stated that the proposed standard is based on a determination that non-emitting techniques constitute BSER for liquids unloading operations. At the same time, the commenter pointed out that the EPA acknowledged that non-emitting techniques are not always feasible or safe and EPA provides alternative standards to cover those situations.

Several of the commenters also requested that the EPA not require recordkeeping and reporting of non-venting liquids unloading events. Commenters suggested that operators conducting liquids unloading operations with zero methane and VOC emissions should not be subject to burdensome recordkeeping, reporting and other requirements. Another commenter noted that the non-vented liquids unloading reporting requirements proposed in the December 2022 Supplemental Proposal are not feasible due to the nature of those events and because of the administrative burden associated with the reporting requirements with no net gain in emission reductions.

In the final rule, the EPA requires that each well affected facility gas well that unloads liquids to employ techniques or technologies that minimize or eliminate venting of emissions during liquids unloading events to the maximum extent. For unloading technologies or techniques that result in venting to the atmosphere, the final rule requires that owners or operators employ best management practices that meet minimum specified criteria to minimize venting of methane and VOC emissions for each gas well liquids unloading operation. This reduces the burden on industry (including small businesses) from what was proposed in the December 2022 Supplemental Proposal by not requiring a zero methane and VOC emissions

[154] See section XI.F.3 of the final rule preamble.

standard be met unless an owner or operator can document that it was technically infeasible or not safe to meet the zero emissions standard.

The EPA also evaluated the commenters' concerns and examples provided regarding the burden associated with the proposed liquids unloading operations recordkeeping and reporting requirements. The EPA has determined that requiring an owner or operator to comply with some of the proposed recordkeeping and reporting requirements in instances where an unloading event does not result in venting to the atmosphere would impose a burden without any added benefit environmentally (e.g., requiring that the number of liquids unloading events that occurred when implementing a non-venting liquids unloading technology or technique be tracked and reported). As a result, the final rule has been changed so that an owner or operator of a well affected facility that employs non-venting liquids unloading technologies and techniques is only required to comply with minimal recordkeeping and reporting requirements (i.e., identification of the well affected facility and non-venting technology or technology employed; number of unplanned venting events). In instances where there may be an unplanned venting event, that event would be subject to the best management practices to minimize venting of emissions and the associated recordkeeping and reporting requirements.

The EPA believes that the final work practice standard and associated recordkeeping and reporting requirements will result in the minimization or elimination of venting of emissions to the maximum extent possible during liquids unloading events, while streamlining the recordkeeping and reporting requirements to minimize burden to industry (including small businesses).

4.5 Employment Impacts of Environmental Regulation

This section presents an overview of the various ways that environmental regulation can affect employment.[155] Employment impacts of environmental regulations are generally composed of a mix of potential declines and gains in different areas of the economy over time. Regulatory employment impacts can vary across occupations, regions, and industries; by labor and product demand and supply elasticities; and in response to other labor market conditions. Isolating such

[155] Additionally, see Section 4.3.5 for a discussion of the demographic characteristics of oil and natural gas workers and communities.

impacts is a challenge, as they are difficult to disentangle from employment impacts caused by a wide variety of ongoing, concurrent economic changes. The EPA continues to explore the relevant theoretical and empirical literature and to seek public comments to ensure that the way the EPA characterizes the employment effects of its regulations is reasonable and informative.

Environmental regulation "typically affects the distribution of employment among industries rather than the general employment level" (Arrow et al., 1996). Even if impacts are small after long-run market adjustments to full employment, many regulatory actions have transitional effects in the short run (OMB, 2015). These movements of workers in and out of jobs in response to environmental regulation are potentially important and of interest to policymakers. Transitional job losses have consequences for workers that operate in declining industries or occupations, have limited capacity to migrate, or live in communities or regions with high unemployment rates.

As indicated by the potential impacts on oil and natural gas markets discussed in Section 0, the final NSPS OOOOb and EG OOOOc are projected to cause small changes in oil and natural gas production and prices. As a result, demand for labor employed in oil and natural gas-related activities and associated industries might experience adjustments as there may be increases in compliance-related labor requirements as well as changes in employment due to quantity effects in directly regulated sectors and sectors that consume oil and natural gas products.

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5 COMPARISON OF BENEFITS AND COSTS

5.1 Comparison of Benefits and Costs

A comparison of quantified benefits and costs is presented below. All estimates are in 2019 dollars. Also, all compliance costs, emissions changes, and benefits are estimated for the years 2024 to 2038 relative to a baseline without the final NSPS OOOOb and EG OOOOc.

Table 5-1Table 5-1 summarizes the emissions reductions associated with the final standards over the 2024 to 2038 period for the NSPS OOOOb, the EG OOOOc, and the NSPS OOOOb and EG OOOOc combined. Tables 5-2Table 5-2, 5-3Table 5-3, and 5-4Table 5-4 present the present value (PV) and equivalent annual value (EAV), estimated using discount rates of 2, 3, and 7 percent, of the changes in quantified climate and health benefits, costs, and net benefits, as well as the emissions reductions relative to the baseline for the NSPS OOOOb, for the EG OOOOc, and the NSPS OOOOb and EG OOOOc, respectively.[156,157] These values reflect an analytical time horizon of 2024 to 2038, are discounted to 2021, and presented in 2019 dollars. These tables include consideration of the non-monetized benefits associated with the emissions reductions projected under this final rule.

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[156] Monetized climate effects are presented under a 2 percent near-term Ramsey discount rate, consistent with EPA's updated estimates of the SC-GHG. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. While this RIA was being drafted and reviewed, OMB finalized an update to Circular A-4, in which it recommended the general application of a 2.0 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC-GHG estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG. See Section 3.2 for more discussion.

[157] The EPA has also applied its updated estimates of the social cost of carbon dioxide (SC-CO_2) in an illustrative analysis of potential climate disbenefits from secondary CO_2 emissions associated with control techniques for storage vessels. Given that the estimated climate disbenefits from the CO_2 impacts would at most offset only about 1 percent of the methane benefits, the EPA finds that the summary values shown in this table are a reasonable estimate of the net monetized climate effects of the rule. See Section 3.9 for further discussion.

Table 5-1 Projected Emissions Reductions under the Final NSPS OOOOb and EG OOOOc across Regulatory Options, 2024–2038[a,b,c]

Regulatory Option	Final Rule	Emissions Changes: Methane (millions short tons)	VOC (millions short tons)	HAP (millions short tons)	Methane (million metric tons CO_2 Eq. using GWP=28)
Less Stringent					
	NSPS OOOOb	23	6.9	0.26	580
	EG OOOOc	31	7.5	0.28	780
	Total	**54**	**14**	**0.54**	**1,400**
Final Rule					
	NSPS OOOOb	23	7.1	0.27	590
	EG OOOOc	35	8.6	0.32	890
	Total	**58**	**16**	**0.59**	**1,500**
More Stringent					
	NSPS OOOOb	23	7.1	0.27	590
	EG OOOOc	35	8.7	0.33	890
	Total	**59**	**16**	**0.59**	**1,500**

[a] Numbers rounded to two significant digits unless otherwise noted. Totals may not appear to add correctly due to rounding. To convert from short tons to metric tons, multiply the short tons by 0.907. Alternatively, to convert metric tons to short tons, multiply metric tons by 1.102.
[b] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC and HAP emissions.
[c] The control techniques to meet the storage vessel-related standards are associated with several types of secondary emissions impacts, which may partially offset the direct benefits of this rule. As discussed in Section 3.9, the magnitude of these secondary air pollutant increases is small relative to the direct emission reductions anticipated from this rule.

Table 5-2 Projected Benefits, Compliance Costs, and Emissions Reductions across Regulatory Options for the Final NSPS OOOOb, 2024–2038 (million 2019$)

	2 Percent Near-Term Ramsey Discount Rate					
	PV	EAV	PV	EAV	PV	EAV
Climate Benefits[b]						
Less Stringent	$43,000	$3,300	$43,000	$3,300	$43,000	$3,300
Final Rule	$44,000	$3,400	$44,000	$3,400	$44,000	$3,400
More Stringent	$44,000	$3,400	$44,000	$3,400	$44,000	$3,400
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Ozone Health Benefits[c]						
Less Stringent	N/A	N/A	N/A	N/A	N/A	N/A
Final Rule	N/A	N/A	N/A	N/A	N/A	N/A
More Stringent	N/A	N/A	N/A	N/A	N/A	N/A
Net Compliance Costs						
Less Stringent	$5,800	$450	$5,700	$480	$5,200	$570
Final Rule	$5,800	$450	$5,800	$480	$5,300	$580
More Stringent	$6,000	$460	$5,900	$490	$5,300	$590
Compliance Costs						
Less Stringent	$14,000	$1,100	$13,000	$1,100	$9,900	$1,100
Final Rule	$14,000	$1,100	$13,000	$1,100	$10,000	$1,100
More Stringent	$14,000	$1,100	$13,000	$1,100	$10,000	$1,100
Value of Product Recovery						
Less Stringent	$7,800	$610	$7,000	$590	$4,700	$510
Final Rule	$7,900	$620	$7,100	$590	$4,700	$520
More Stringent	$7,900	$620	$7,100	$600	$4,700	$520
Net Monetized Benefits[d]						
Less Stringent	$37,000	$2,900	$37,000	$2,900	$38,000	$2,800
Final Rule	$38,000	$3,000	$38,000	$2,900	$39,000	$2,800
More Stringent	$38,000	$3,000	$38,000	$2,900	$39,000	$2,800
Non-Monetized Benefits						
Benefits to provision of ecosystem services and ozone-related health benefits from reducing methane emissions by (in short tons):						
Less Stringent						23,000,000
Final Rule						23,000,000
More Stringent						23,000,000
Benefits to provision of ecosystem services from reducing VOC emissions by (in short tons):						
Less Stringent						6,900,000
Final Rule						7,100,000
More Stringent						7,100,000
$PM_{2.5}$-related health benefits from reducing VOC emissions by (in short tons)[b]:						
Less Stringent						6,900,000

Final Rule	7,100,000
More Stringent	7,100,000
Benefits to provision of ecosystem services and HAP-related health benefits from reducing HAP emissions by (in short tons):	
Less Stringent	260,000
Final Rule	270,000
More Stringent	270,000

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane ($SC\text{-}CH_4$) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the $SC\text{-}CH_4$ at the 2 percent near-term Ramsey discount rate. Please see Tables 3.4 and 3.5 for the full range of monetized climate benefit estimates.
[c] The ozone-related health benefits estimates use the larger of the two benefits estimates presented in Table 3-10. Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.
[d] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 3.2 for a discussion of climate effects that are not yet reflected in the $SC\text{-}CH_4$ and thus remain unmonetized and Sections 3.4 through 3.8 for a discussion of other nonmonetized benefits.

Table 5-3 Projected Benefits, Compliance Costs, and Emissions Reductions across Regulatory Options for the Final EG OOOOc, 2024–2038 (million 2019$)

	2 Percent Near-Term Ramsey Discount Rate					
	PV	EAV	PV	EAV	PV	EAV
Climate Benefits[b]						
Less Stringent	$57,000	$4,500	$57,000	$4,500	$57,000	$4,500
Final Rule	$65,000	$5,100	$65,000	$5,100	$65,000	$5,100
More Stringent	$66,000	$5,100	$66,000	$5,100	$66,000	$5,100
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Ozone Health Benefits[c]						
Less Stringent	N/A	N/A	N/A	N/A	N/A	N/A
Final Rule	N/A	N/A	N/A	N/A	N/A	N/A
More Stringent	N/A	N/A	N/A	N/A	N/A	N/A
Net Compliance Costs						
Less Stringent	$12,000	$940	$11,000	$930	$7,900	$870
Final Rule	$13,000	$1,000	$12,000	$1,000	$8,900	$970
More Stringent	$38,000	$2,900	$35,000	$3,000	$27,000	$2,900
Compliance Costs						
Less Stringent	$16,000	$1,300	$15,000	$1,200	$10,000	$1,100
Final Rule	$18,000	$1,400	$16,000	$1,400	$12,000	$1,300
More Stringent	$43,000	$3,300	$40,000	$3,300	$30,000	$3,300
Value of Product Recovery						
Less Stringent	$4,100	$320	$3,700	$310	$2,400	$260
Final Rule	$4,700	$370	$4,200	$350	$2,700	$300
More Stringent	$5,000	$390	$4,400	$370	$2,900	$320
Net Monetized Benefits[d]						
Less Stringent	$45,000	$3,500	$46,000	$3,500	$50,000	$3,600
Final Rule	$52,000	$4,100	$53,000	$4,100	$56,000	$4,100
More Stringent	$28,000	$2,200	$31,000	$2,200	$39,000	$2,200
Non-Monetized Benefits						
Benefits to provision of ecosystem services and ozone-related health benefits from reducing methane emissions by (in short tons):						
Less Stringent						31,000,000
Final Rule						35,000,000
More Stringent						35,000,000
Benefits to provision of ecosystem services from reducing VOC emissions by (in short tons):						
Less Stringent						7,500,000
Final Rule						8,600,000
More Stringent						8,700,000
$PM_{2.5}$-related health benefits from reducing VOC emissions by (in short tons)[b]:						
Less Stringent						7,500,000

Final Rule	8,600,000
More Stringent	8,700,000
Benefits to provision of ecosystem services and HAP-related health benefits from reducing HAP emissions by (in short tons):	
Less Stringent	280,000
Final Rule	320,000
More Stringent	330,000

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane ($SC\text{-}CH_4$) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the $SC\text{-}CH_4$ at the 2 percent near-term Ramsey discount rate. Please see Table 3.4 and 3.5 for the full range of monetized climate benefit estimates.
[c] The ozone-related health benefits estimates use the larger of the two benefits estimates presented in Table 3-10. Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.
[d] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 3.2 for a discussion of climate effects that are not yet reflected in the $SC\text{-}CH_4$ and thus remain unmonetized and Sections 3.4 through 3.8 for a discussion of other nonmonetized benefits.

Table 5-4 Projected Benefits, Compliance Costs, and Emissions Reductions across Regulatory Options for the Final NSPS OOOOb and EG OOOOc, 2024–2038 (million 2019$)

	2 Percent Near-Term Ramsey Discount Rate					
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Climate Benefits[b]						
Less Stringent	$100,000	$7,800	$100,000	$7,800	$100,000	$7,800
Final Rule	$110,000	$8,500	$110,000	$8,500	$110,000	$8,500
More Stringent	$110,000	$8,500	$110,000	$8,500	$110,000	$8,500
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Ozone Health Benefits[c]						
Less Stringent	$6,300	$490	$5,400	$450	$3,100	$340
Final Rule	$7,000	$540	$6,100	$510	$3,500	$380
More Stringent	$7,100	$550	$6,100	$510	$3,500	$390
Net Compliance Costs						
Less Stringent	$18,000	$1,400	$17,000	$1,400	$13,000	$1,400
Final Rule	$19,000	$1,500	$18,000	$1,500	$14,000	$1,600
More Stringent	$44,000	$3,400	$41,000	$3,400	$32,000	$3,500
Compliance Costs						
Less Stringent	$30,000	$2,300	$27,000	$2,300	$20,000	$2,200
Final Rule	$31,000	$2,400	$29,000	$2,400	$22,000	$2,400
More Stringent	$57,000	$4,400	$53,000	$4,400	$40,000	$4,400
Value of Product Recovery						
Less Stringent	$12,000	$930	$11,000	$900	$7,100	$780
Final Rule	$13,000	$980	$11,000	$950	$7,400	$820
More Stringent	$13,000	$1,000	$12,000	$970	$7,600	$840
Net Monetized Benefits[d]						
Less Stringent	$89,000	$6,900	$89,000	$6,900	$90,000	$6,700
Final Rule	$97,000	$7,600	$97,000	$7,500	$98,000	$7,300
More Stringent	$73,000	$5,700	$75,000	$5,600	$81,000	$5,400
Non-Monetized Benefits						
Benefits to provision of ecosystem services and ozone-related health benefits from reducing methane emissions by (in short tons):						
Less Stringent						31,000,000
Final Rule						35,000,000
More Stringent						35,000,000
Benefits to provision of ecosystem services from reducing VOC emissions by (in short tons):						
Less Stringent						7,500,000
Final Rule						8,600,000
More Stringent						8,700,000
$PM_{2.5}$-related health benefits from reducing VOC emissions by (in short tons)[b]:						
Less Stringent						7,500,000

Final Rule	8,600,000
More Stringent	8,700,000
Benefits to provision of ecosystem services and HAP-related health benefits from reducing HAP emissions by (in short tons):	
Less Stringent	280,000
Final Rule	320,000
More Stringent	330,000

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate. Please see Table 3.4 and 3.5 for the full range of monetized climate benefit estimates.
[c] The ozone-related health benefits estimates use the larger of the two benefits estimates presented in Table 3-10. Monetized benefits include those related to public health associated with reductions in ozone concentrations. The health benefits are associated with several point estimates.
[d] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 3.2 for a discussion of climate effects that are not yet reflected in the SC-CH_4 and thus remain unmonetized and Sections 3.4 through 3.8 for a discussion of other nonmonetized benefits.

The following two tables show the total emissions reductions and the PV and EAV of net compliance costs over the 2024 to 2038 period. The projected net compliance costs for reciprocating compressors (in all segments) and wet seal centrifugal compressors (processing segment only) are negative, as the projected revenue from product recovery exceeds the projected cost increases. This observation may typically support an assumption that operators would continue to perform the emissions abatement activity, regardless of whether a requirement is in place, because it is in their private self-interest. However, the reciprocating compressors are in the gathering and boosting, processing, transmission, and storage segments. As discussed in previous oil and natural gas NSPS RIAs, operators in those segments of the industry do not typically own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, financial incentives to reduce emissions may be minimal because operators are not able to recoup the financial value of captured natural gas that may otherwise be emitted. Alternatively, there may also be an opportunity cost associated with the installation of environmental controls (for purposes of mitigating the emission of pollutants) that is not reflected in the control costs. In the event that the environmental investment displaces investment in productive capital, the difference between the rate of return on the marginal investment displaced by the mandatory environmental investment is a measure of the opportunity cost of the environmental requirement to the regulated entity. However, if firms are not capital constrained — as is likely to be the case for firms that can access liquid capital markets — then there may not be any displacement of investment, and the rate of return on other investments in the industry would not be relevant as a measure of opportunity cost.[158] If firms face higher borrowing costs as they take on more debt, there may be an additional opportunity cost to the firm**.** To the extent that any opportunity costs are not added to the control costs, the compliance cost reductions presented above may be underestimated.

Table 5-5 Projected Emissions Reductions for Incrementally Affected Sources under the Final NSPS OOOOb and EG OOOOc, 2024 to 2038

		Nationwide Emissions Reductions			
Segment	**Source**	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO_2 Eq.)**
Production	Fugitives: Components	5,500,000	1,500,000	58,000	140,000,000
	Fugitives: Storage Vessel Flares	10,000,000	2,900,000	110,000	260,000,000
	Pneumatics	26,000,000	7,300,000	270,000	660,000,000
	Storage Vessels	150,000	700,000	26,000	3,900,000
	Associated Gas	4,900,000	1,400,000	51,000	120,000,000
	Liquids Unloading	260,000	73,000	2,800	6,700,000
Gathering and Boosting	Fugitives	730,000	200,000	7,600	18,000,000
	Pneumatics	2,400,000	670,000	25,000	61,000,000
	Reciprocating Compressors	2,100,000	580,000	22,000	53,000,000
	Wet-Seal Centrifugal Compressors	970,000	270,000	10,000	25,000,000
Natural Gas Processing	Leaks	180,000	21,000	610	4,500,000
	Reciprocating Compressors	710,000	20,000	580	18,000,000
	Wet-Seal Centrifugal Compressors	400,000	11,000	330	10,000,000
Transmission and Storage	Fugitives	890,000	25,000	730	23,000,000
	Pneumatics	560,000	16,000	460	14,000,000
	Reciprocating Compressors	1,700,000	48,000	1,400	44,000,000
	Wet-Seal Centrifugal Compressors	280,000	7,700	230	7,100,000

Note: Values rounded to two significant figures.

[158] See Circular A-4: Explanation and Response to Public Input 81-87 (OMB 2023).

Table 5-6 Projected Climate Benefits and Compliance Costs (millions 2019$) for Incrementally Affected Sources under the Final NSPS OOOOb and EG OOOOc Option, 2024 to 2038[a,b]

		Costs and Benefits (PV, million 2019$)			
Segment	Source	Climate Benefits	Capital Cost	Annualized Cost, without Product Recovery	Annualized Cost, with Product Recovery
Production	Fugitives	$30,000	$300	$8,200	$7,400
	Pneumatics	$49,000	$7,200	$4,400	$730
	Storage Vessels	$290	$620	$1,600	$1,600
	Associated Gas	$9,100	$20,000	$15,000	$8,600
	Liquids Unloading	$490	$0	$140	$100
Gathering and Boosting	Fugitives	$1,400	$25	$580	$470
	Pneumatics	$4,500	$880	$1,100	$760
	Reciprocating Compressors	$4,000	$130	$280	-$20
	Wet-Seal Centrifugal Compressors	$1,800	$0	$86	-$52
Natural Gas Processing	Leaks	$330	$0	$36	$12
	Reciprocating Compressors	$1,300	$44	$62	-$34
	Wet-Seal Centrifugal Compressors	$760	$0	$59	$4
Transmission and Storage	Fugitives	$1,700	$70	$310	$200
	Pneumatics	$1,100	$320	$280	$210
	Reciprocating Compressors	$3,200	$92	$140	-$77
	Wet-Seal Centrifugal Compressors	$520	$0	$160	$120

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding. Costs and climate benefits in each year are discounted to 2021.
[b] Due to time and resource limitations, we are unable to estimate the monetized ozone benefits on a source-by-source basis. Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table.
[c] Climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate.

5.2 Uncertainties and Limitations

Throughout the RIA, we considered several sources of uncertainty, both quantitatively and qualitatively, regarding the emissions reductions, benefits, and costs estimated for the final rule. We summarize the key elements of our discussions of uncertainty below.

Source-level compliance costs and emissions impacts: As discussed in Section 2.2, the first step in the compliance cost analysis is the development of per-facility national-average representative costs and emissions impacts using a model plant approach. The model plants are designed based upon the best information available to the Agency at the time of the rulemaking. By emphasizing facility averages, geographic variability, and heterogeneity across producers in the industry is masked, and regulatory impacts at the facility-level may vary from the model plant averages. This assumption is particularly important when assessing the impacts of requirements that depend on thresholds, such as for storage vessels. For a well site group, which represents a collection of well sites and their average characteristics, all sites within the group are categorized as either being below or above the emissions limit, though it may be the case that some sites within the group exceed the limit while others do not. Misspecifications of this sort may average out across the full set of well site groups.

There may also be an opportunity cost associated with the installation of environmental controls (for purposes of mitigating the emissions of pollutants) that is not reflected in the control costs. In the event that investment in environmental compliance displaces other investment in productive capital, the difference between the rate of return on the investment displaced by the mandatory environmental investment is a measure of the opportunity cost of the environmental requirement. To the extent that such opportunity costs of capital are not accounted for in the estimated compliance cost reductions, the cost reductions may be underestimated.

Projection methods and assumptions: As discussed in Section 2.2.1, the second component in estimating national impacts is the projection of affected facilities. Uncertainties in the projections informing this RIA results include: 1) choice of projection method; 2) data sources and drivers; 3) limited information about rate of modification and turnover of sources; 4) behavioral responses to regulation; and 5) unforeseen changes in industry and economic shocks. The list of assumptions required to inform the analysis is too numerous to provide a comprehensive list, but a few key drivers of the results warrant specific mention.

2016 ICR Data: As discussed previously, the 2016 Oil and Natural Gas ICR was withdrawn in 2017. Therefore, the data represent an incomplete, and possibly unrepresentative, survey of operators and well sites. Even so, we believe that it represents the best available data to use for this analysis, as it includes additional variables beyond, and many more well site observations than, other equipment surveys that we are aware of (e.g., the API well site survey discussed in Section 2.2.1.2, which was used to estimate the distribution of fugitive emissions from components at well sites for the November 2021 RIA). To date, we have not formally analyzed the representativeness of the data collected. Informal benchmarks, such as the proportions of single-well versus multi-well sites and low production versus non-low production sites and average equipment counts, when compared to outside data sources that attempt to capture the universe of well sites (such as Enverus and GHGI), did not suggest significant issues with the representativeness of the ICR data.

Site/Equipment Retirement and Modification: Our assumptions on non-well site retirement rates are based on impressions stemming from conversations with, and comments from, industry stakeholders and are not derived from data sources due to a lack of information. Our assumptions for well site retirement rates are based on an analysis of Enverus data, but we are still assessing improvements to our methods for estimating those rates. In all cases, we assume that, prior to implementation of the NSPS and EG, equipment at sites shares the same vintage as the sites themselves. For example, if a well site was constructed prior to the promulgation of NSPS OOOO, we assume that all controllers at the site pre-date the NSPS OOOO as well and are not replaced until the EG goes into effect in 2028. By not accounting for the possibility of equipment replacements and site modifications, we may be overstating the impacts for some sources that were constructed prior to the NSPS OOOO and/or NSPS OOOOa but are now subject to those rules.

Years of analysis: The years of analysis are 2024, to represent the full first-year facilities are affected by this action, through 2038, to represent impacts of the rule over a longer period, as discussed in Section 2.2. While it would be desirable to analyze impacts beyond 2038 in this RIA, the EPA has chosen not to do this largely because of the limited information available on the turnover rate of emissions sources and controls. Extending the analysis beyond 2038 would introduce substantial and increasing uncertainties in the projected impacts of the rule. That said, some amount of both benefits and costs would likely continue after 2038, and we note that toward the end of our analytical time horizon, undiscounted net costs are relatively steady from year to year (Table 2-12) while undiscounted monetized climate benefits (Table 3-4) are rising each year. It is therefore plausible that significant net benefits would continue in the years after 2038, though for the reasons given, we do not currently attempt to monetize these effects.

Treatment of sources in Alaska: The RIA does not account for instances in which all or some sources in Alaska are subject to different requirements than those in the rest of the country, both in the baseline due to previous rulemakings and in this final rule. For example, the 2018 amendments to the 2016 NSPS OOOOa ("Alaska Amendments") reduced fugitives monitoring frequency requirements for well sites and compressor stations on the Alaska North Slope.[159] We do not reflect those reduced requirements in the baseline in this RIA, nor do we reflect that the same reduced requirements are being finalized for the NSPS OOOOb and EG OOOOc. In addition, for sites in Alaska, the NSPS OOOOb and EG OOOOc only requires non-emitting pneumatic controllers to be installed at sites where onsite power is available; otherwise, the requirement is to replace high-bleed controllers with low-bleed controllers and to monitor intermittent bleed controllers for malfunctions. In both cases, these omissions suggest that our analysis may overestimate the impacts of the final regulation.

State rules and voluntary action in the baseline: As discussed in Section 2.2.3, while we accounted for state regulations in California, Colorado, and (to a more limited degree) New Mexico and Pennsylvania, there are many other state and local requirements that may be in the baseline that we are unable to account for. In addition, the baseline does not reflect voluntary actions firms may take to reduce emissions in the oil and natural gas sector. By not accounting for state and local requirements (outside of Colorado, California, New Mexico, and Pennsylvania) and voluntary actions in the baseline, this analysis may overestimate both the benefits and costs of the final regulation.

Wellhead natural gas prices used to estimate revenues from natural gas recovery: The compliance cost estimates presented in this RIA include the estimates of the revenue associated with the increase in natural gas recovery resulting from compliance actions. As a result, the national compliance cost impacts depend on the price of natural gas. As explained in Section 2.4 natural gas prices used in this analysis are from the projection of the Henry Hub price in the AEO2022. To the extent actual natural gas prices diverge from the AEO projections, the actual impacts will diverge from our estimates.

Oil and natural gas market impact analysis: The oil and natural gas market impact analysis presented in this RIA is subject to several caveats and limitations. As with any modeling exercise, the market impact analysis presented here depends crucially on uncertain input

[159] 83 FR 10628.

parameters and assumptions regarding market structure. A more detailed discussion of the caveats and limitations of the oil and natural gas market impacts analysis can be found in Section 0.

Monetized methane-related climate benefits: The EPA considered the uncertainty associated with the social cost of methane (SC-CH_4) estimates, which were used to calculate the monetized climate benefits of the decrease in methane emissions projected because of this action. Section 3.2 provides a detailed discussion of the limitations and uncertainties associated with the SC-CH_4 estimates used in this analysis and describes ways in which the modeling addresses quantified sources of uncertainty.

Monetized VOC-related ozone benefits: The analysis of monetized VOC-related ozone benefits described in Section 3.3 includes many data sources as inputs that are each subject to uncertainty. Input parameters include projected emissions inventories, projected compliance methods, 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. Below are key uncertainties associated with estimating the number and value of ozone-related premature deaths.

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 segmented lag 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 health impact function without a threshold in modeling both long- and short-term ozone-related mortality. However, we acknowledge reduced confidence in specifying the shape of the concentration-response relationship in the range of 40 ppb and below (U.S. EPA, 2020). Thus, estimates include health benefits from reducing ozone in areas with concentrations of ozone down to the lowest modeled concentrations.

Our estimate of the total monetized ozone-attributable benefits is based on the EPA's interpretation of the best available scientific literature and methods and supported by the SAB-HES and the National Academies of Science (2002, 2008). Since the publication of these reports, the EPA has continued improving its techniques for characterizing uncertainty in the estimated air pollution-attributable benefits. Where possible, we quantitatively assess uncertainty in each input parameter (for example, statistical uncertainty is characterized by performing Monte Carlo simulations). However, in some cases, this type of quantitative analysis is not possible due to lack of data, so we instead characterize the sensitivity of the results to alternative plausible input parameters. And, for some inputs into the benefits analysis, such as the air quality data, we lack the data to perform either a quantitative uncertainty analysis or sensitivity analysis. Additional detail regarding specific uncertainties associated with ozone health benefit estimates can be found in the Health Benefits TSD (U. S. EPA, 2023).

Non-monetized benefits: Several categories of health, welfare, and climate benefits are not quantified in this RIA. These unquantified benefits are described in detail in Section 3.

Non-quantified regulatory impacts: We do not attempt to quantify regulatory impacts for all finalized requirements in this RIA. For a discussion of these requirements, see Section .

Environmental justice analyses: the EPA performed quantitative EJ assessments of baseline HAP cancer risks, ozone exposure and health risks, employment, and household energy expenditures. Each of these analyses are subject to various types of uncertainty related to input parameters and assumptions. Qualitatively, assessments that further subdivide the populations are subject to increased uncertainty as compared to overall exposure and risk estimates.

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