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

ERRATA SHEET

Following the initial posting of the Regulatory Impact Analysis (RIA) on November 11, 2022, this document has been updated with the following technical correction: on page 84, the text "this proposal is projected to reduce 280,000 tons of HAP emissions over the 2023 through 2035 period" has been changed to "this proposal is projected to reduce 390,000 tons of HAP emissions over the 2023 through 2035 period" to reflect the correct estimate of emissions reductions from Table 1-3.

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Regulatory Impact Analysis of the Supplemental Proposal for 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 EXECUTIVE SUMMARY

1.1 Introduction

This document presents the regulatory impact analyses (RIA) for the supplemental notice of proposed rulemaking (hereafter, "supplemental proposal") titled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." The supplemental proposal builds on the proposed rule with the same title published in November 2021 (hereafter, "November 2021 proposal"),[1] providing additions, amendments, and clarification to the November 2021 proposal. This RIA for the supplemental notice projects the potential impacts of these proposed actions cumulatively, including provisions from the November 2021 proposal that have not been updated in the supplemental proposal.

The November 2021 proposal included three distinct actions. First, it proposed to amend existing crude oil and natural gas new source performance standards (NSPS) under the Clean Air Act (CAA) section 111(b); second, it proposed new NSPS for the crude oil and natural gas source category; and third, it proposed emissions guidelines (EG) under CAA section 111(d) which will inform states on the development, submittal, and implementation of state plans to establish performance standards for existing crude oil and natural gas sources. Both the November 2021 and supplemental proposals respond to the President's Executive Order (EO) 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis".[2]

A wide range of stakeholders as well as state and tribal governments submitted public comments on the November 2021 proposal, submitting over 470,000 public comments in total. Many commenters representing diverse perspectives expressed general support for the proposal and requested that the EPA further strengthen the proposed standards and make them more comprehensive. Other commenters highlighted implementation or cost concerns related to elements of the November 2021 proposal or provided specific data and information that the EPA

[1] 86 FR 63110
[2] 86 FR 7037

was able to use to refine or revise several of the standards included in the November 2021 proposal.

The purpose of the supplemental proposed rulemaking is to strengthen, update, and expand the proposed standards for certain emissions sources, including: (1) to reduce emissions from the source category more comprehensively by adding proposed standards for certain sources that were not addressed in the November 2021 proposal, revising the proposed requirements for fugitive emissions monitoring and repair, and establishing a super-emitter response program; (2) to encourage the deployment of innovative technologies and techniques for detecting and reducing methane emissions by providing additional options for the use of advanced monitoring; (3) to modify and refine certain elements of the proposed standards in response to concerns and information submitted in public comments; and (4) to provide additional information not included in the November 2021 proposal for public comment, such as the proposed regulatory text for the new subparts and details of the timelines and other requirements that apply to states as they develop state plans to implement the emission guidelines.

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 proposed rule and the economic theory that supports environmental 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 proposed 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 proposed 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 proposed regulatory actions are evaluated relative to a baseline that represents the world without the proposed action. In this case, we present results for the proposed NSPS OOOOb and EG OOOOc, *taking into account both the November 2021 and supplemental proposals*. In other words, this analysis reflects the totality of the two proposals compared to a baseline without either regulatory action. As in the RIA for the November 2021 proposal, the baseline for the supplemental proposal 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 proposed requirements that result in quantifiable compliance cost or emissions changes compared to the baseline. We do not analyze the regulatory impacts of all proposed 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 2.1.2 for a discussion of provisions for which impacts were not quantified.

Compared to the analysis presented in the RIA for the November 2021 proposal, this analysis reflects changes in the proposed regulation for some sources; 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; and updated assumptions based on new information on existing and projected source counts, emissions factors and control costs, natural gas prices, and state and local regulations that have been promulgated. The updated baseline represents the EPA's most recent assessment of the current and future state of the industry absent the proposed requirements.

Table 1-1 and Table 1-2 summarize the baseline and proposed standards of performance for the sources with impacts quantified in this RIA.[3] 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 (optical gas imaging), AVO (auditory, visual, and optical), scfh (standard cubic feet per hour), and scfm (standard cubic feet per minute).

[3] See the preamble for a more comprehensive description of the proposed standards.

Table 1-1 NSPS OOOOb Emissions Sources, Baseline Requirements, and Requirements under the Proposed Option

	Standards of Performance	
Source	**In the Baseline**	**Under the Proposal**
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 two or more pieces of major equipment or one piece of major equipment and a 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
Gathering and Boosting Stations	No requirement	
Pneumatic Controllers[b]		
Well Sites	Natural gas bleed rate no greater than 6 scfh	Zero emissions[c]
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		
Centrifugal Compressors		
Wet-seal		
Gathering and Boosting Stations	No requirement	95% control
Natural Gas Processing Plants	95% control	
Transmission and Storage Compressor Stations		
Dry-seal		
Gathering and Boosting Stations	No requirement	Volumetric flow rate of 3 scfm
Natural Gas Processing Plants		
Transmission and Storage Compressor Stations		

Liquids Unloading		
Well Sites	No requirement	Zero emissions or best management practices[d]
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

[a] Well sites and compressor stations on the Alaska North Slope are subject to Annual OGI monitoring only.
[b] Specifically, the affected source is natural gas-driven controllers that vent to the atmosphere.
[c] 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.
[d] The proposed 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 Proposed Option

	Presumptive Standards of Performance	
Source	**In the Baseline**	**Under the Proposal**
Fugitive Emissions/Equipment Leaks[a]		
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
Gathering and Boosting Stations	No requirement	

Pneumatic Controllers[b]		
Well Sites	Pre-OOOO: No requirement Post-OOOO: Natural gas bleed rate no greater than 6 scfh	Methane emission rate of zero[c]
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	
Centrifugal Compressors		
Wet-seal		
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		
Dry-seal		
Gathering and Boosting Stations	No requirement	Volumetric flow rate of 3 scfm
Natural Gas Processing Plants		
Transmission and Storage Compressor Stations		
Liquids Unloading		
Well Sites	No requirement	Zero emissions or best management practices[d]
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	

[a] Well sites and compressor stations on the Alaska North Slope are subject to Annual OGI monitoring only.
[b] Specifically, the affected source is natural gas-driven controllers that vent to the atmosphere.
[c] 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.
[d] The proposed 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.[4] To project activity data for regulated facilities, we first project activity data for oil and 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 EPA's Greenhouse Gas Inventory (GHGI), regulated facilities are apportioned to sites across all industry segments.[5] 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 proposed NSPS OOOOb and EG OOOOc from 2023 to 2035. The initial analysis year is 2023 as we assume the proposed rule will be finalized early in that year. The NSPS OOOOb is assumed to take effect

[4] Regulated facilities include well site fugitives, 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, and storage vessels.
[5] Industry segments include production, gathering and boosting, processing, transmission, and storage.

immediately and impact sources constructed after publication of the November 2021 proposal.[6] 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 three years, and so EG OOOOc impacts will begin in 2026. The final analysis year is 2035, which allows us to present ten years of regulatory impacts after state plans under the EG OOOOc are assumed to take effect.

1.4 Summary of Key Results

A summary of the key results is shown below. All dollar estimates are in 2019 dollars. Also, all compliance costs, emissions changes, and benefits are estimated for the years 2023 to 2035 relative to a baseline without the proposed NSPS OOOOb and EG OOOOc.

Table 1-3 summarizes the emissions reductions associated with the proposed standards over the 2023 to 2035 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 25.[7]

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[6] As explained in the preamble to supplemental proposal, NSPS OOOOb would apply to all emissions sources ("affected facilities") identified in the proposed 40 CFR 60.5365b, except dry seal centrifugal compressors, that commenced construction, reconstruction, or modification after November 15, 2021. NSPS OOOOb would apply to dry seal centrifugal compressor affected facilities that commence construction, reconstruction, or modification after publication of the supplemental proposal in the Federal Register.

[7] 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 (CO2).

Table 1-3 Projected Emissions Reductions under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035[a,b]

Proposal	Emissions Changes			
	Methane (million short tons)	VOC (million short tons)	HAP (million short tons)	Methane (million metric tons CO_2 Eq. using GWP=25)
NSPS OOOOb	8.1	2.9	0.11	180
EG OOOOc	28	6.8	0.28	620
Total	36	9.7	0.39	810

[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 emissions.

Table 1-4, Table 1-5, and Table 1-6 present results for the proposal 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 3 and 7 percent, of the changes in quantified benefits, costs, and net benefits, as well as the emissions reductions relative to the baseline. These values reflect an analytical time horizon of 2023 to 2035, are discounted to 2021, 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.[8] The table includes consideration of the non-monetized benefits associated with the emissions reductions projected under this proposal.

[8] Under this proposal, over 80 percent of revenue from the sale of captured natural gas is projected to be earned by operators in the production and processing segments 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 transmission and storage segment, 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, 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.

Table 1-4 Projected Benefits, Compliance Costs, and Emissions Reductions for the Proposed NSPS OOOOb Option, 2023–2035 (million 2019$)

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[a]	$11,000	$1,000	$11,000	$1,000
	3 Percent Discount Rate		**7 Percent Discount Rate**	
	PV	EAV	PV	EAV
Net Compliance Costs	$3,300	$360	$3,000	$360
Compliance Costs	$4,400	$460	$3,700	$440
Value of Product Recovery	$1,000	$99	$730	$88
Net Benefits	$7,600	$670	$7,900	$670
Non-Monetized Benefits	Climate and ozone health benefits from reducing 8.1 million short tons of methane from 2023 to 2035 $PM_{2.5}$ and ozone health benefits from reducing 2.9 million short tons of VOC from 2023 to 2035[b] HAP benefits from reducing 110 thousand short tons of HAP from 2023 to 2035 Visibility benefits Reduced vegetation effects			

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[a] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from $4.4 billion to $29 billion ($470 million to $2.7 billion) over 2023 to 2035 for the proposed option. Please see Table 3-5 and Table 3-8 for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). All net benefits are calculated using climate benefits discounted at 3 percent.
[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix C of the RIA.

Table 1-5 Projected Benefits, Compliance Costs, and Emissions Reductions for the Proposed EG OOOOc Option, 2023–2035 (million 2019$)

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[a]	$37,000	$3,500	$37,000	$3,500
	3 Percent Discount Rate		**7 Percent Discount Rate**	
	PV	EAV	PV	EAV
Net Compliance Costs	$11,000	$990	$8,700	$1,000
Compliance Costs	$14,000	$1,300	$11,000	$1,300
Value of Product Recovery	$3,600	$340	$2,500	$300
Net Benefits	$26,000	$2,500	$28,000	$2,400
Non-Monetized Benefits	Climate and ozone health benefits from reducing 28 million short tons of methane from 2023 to 2035 $PM_{2.5}$ and ozone health benefits from reducing 6.8 million short tons of VOC from 2023 to 2035[b,c] HAP benefits from reducing 280 thousand short tons of HAP from 2023 to 2035 Visibility benefits Reduced vegetation effects			

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

[a] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane ($SC\text{-}CH_4$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average $SC\text{-}CH_4$ at a 3 percent discount rate, but the Agency does not have a single central $SC\text{-}CH_4$ point estimate. We emphasize the importance and value of considering the benefits calculated using all four $SC\text{-}CH_4$ estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from $15 billion to $98 billion ($1.6 billion to $9.3 billion) over 2023 to 2035 for the proposed option. Please see Table 3-5 and Table 3-8 for the full range of $SC\text{-}CH_4$ estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of $SC\text{-}CH_4$ estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). All net benefits are calculated using climate benefits discounted at 3 percent.

[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix C of the RIA.

[c] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

Table 1-6 Projected Benefits, Compliance Costs, and Emissions Reductions for the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (million 2019$)

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[a]	$48,000	$4,500	$48,000	$4,500
	3 Percent Discount Rate		**7 Percent Discount Rate**	
	PV	EAV	PV	EAV
Net Compliance Costs	$14,000	$1,400	$12,000	$1,400
Compliance Costs	$19,000	$1,800	$15,000	$1,800
Value of Product Recovery	$4,600	$440	$3,300	$390
Net Benefits	$34,000	$3,200	$36,000	$3,100
Non-Monetized Benefits	Climate and ozone health benefits from reducing 36 million short tons of methane from 2023 to 2035 $PM_{2.5}$ and ozone health benefits from reducing 9.7 million short tons of VOC from 2023 to 2035[b,c] HAP benefits from reducing 390 thousand short tons of HAP from 2023 to 2035 Visibility benefits Reduced vegetation effects			

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[a] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from $19 billion to $130 billion ($2.1 billion to $12 billion) over 2023 to 2035 for the proposed option. Please see Table 3-5 and Table 3-8 for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). All net benefits are calculated using climate benefits discounted at 3 percent.
[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix C of the RIA.
[c] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

1.5 Organization of RIA

Section 2 describes the projected compliance cost and emissions impacts from the proposal, including the PV and EAV of the projected costs over the 2023 to 2035 period and the associated EAV. Section 3 describes the projected climate benefits resulting from this proposal, including the PV and EAV of the projected climate benefits over the 2023 to 2035 period. Section 3 additionally considers the potential beneficial climate, health, and welfare impacts that could not be quantified. Section 4 describes the economic impact and distributional analysis associated with the proposed rule. The economic impact and distributional analysis section includes analysis of oil and natural gas market impacts, 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. The RIA includes three appendices, which provide further detail on the projection of affected sources (Appendix A), a sensitivity analysis of the monetized climate benefits using newly developed SC-CH_4 estimates (Appendix B), and a screening analysis of monetized ozone benefits from VOC reductions (Appendix C).

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 proposed rule for the 2023 to 2035 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.

2.1 Emissions Sources and Regulatory Requirements Analyzed in this RIA

A series of emissions sources and controls were evaluated as part of the proposed NSPS OOOOb and EG OOOOc review. 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 2.1.2 describes the regulatory choices within the proposed 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) for the supplemental proposal, hereafter referred to as the Supplemental TSD (U.S. EPA, 2022),[9] and the TSD for the November 2021 proposal, hereafter referred to as the November 2021 TSD (U.S. EPA, 2021e).

2.1.1 Emissions Sources

The section provides brief descriptions of the emissions sources subject to the requirements in the proposed NSPS OOOOb and EG OOOOc. EPA presents more detailed modeling, assumptions and other crucial information, and additional technical detail in the preamble, the Supplemental TSD and accompanying FEAST memo,[10] and the November 2021 TSD.

Fugitive Emissions:[11] There are several potential sources of fugitive emissions throughout the crude oil and natural gas production source category. Fugitive emissions occur

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[9] Available at https://www.regulations.gov/ under Docket No. EPA-HQ-OAR-2021-0317.
[10] Memorandum. *Modeling Fugitive Emissions from Production Sites Using FEAST*. Prepared by RTI International for Karen Marsh, SPPD/OAQPS/EPA. July 27, 2022. Docket No. EPA-HQ-OAR-2021-0317.
[11] See Chapter 5 of the Supplemental TSD and the FEAST memo for more information.

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 emissions (e.g., an intermittent pneumatic controller that is venting continuously).

Pneumatic Controllers:[12] 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

[12] See Chapter 3 of the Supplemental TSD for more information.

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.

Pneumatic Pumps:[13] 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:[14] 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,

[13] See Chapter 4 of the Supplemental TSD for more information.
[14] See Chapter 7 of the November 2021 TSD for more information.

and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder.

Centrifugal Compressors:[15] 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 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:[16] 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

[15] See Chapter 2 of the Supplemental TSD for more information.
[16] See Chapter 6 of the November 2021 TSD for more information.

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. 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:[17] 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

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

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 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:[18] 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

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

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.

2.1.2 Regulatory Requirements

Table 2-1 and Table 2-2 summarize the baseline and proposed standards of performance for the sources with impacts quantified in this RIA.[19] 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 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 Requirements under the Proposed Option

	Standards of Performance	
Source	**In the Baseline**	**Under the Proposal**
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 two or more pieces of major equipment or one piece of major equipment and a 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	Quarterly OGI	Monthly AVO monitoring + Quarterly OGI
Natural Gas Processing Plants	NSPS Subpart VVa	Bimonthly OGI
Pneumatic Pumps		
Well Sites	95% control	Zero emissions
Gathering and Boosting Stations	No requirement	Zero emissions

[19] See the preamble for a more comprehensive description of the proposed standards.

Pneumatic Controllers[b]		
Well Sites	Natural gas bleed rate no greater than 6 scfh	Zero emissions[c]
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		
Centrifugal Compressors		
Wet-seal		
Gathering and Boosting Stations	No requirement	95% control
Natural Gas Processing Plants	95% control	
Transmission and Storage Compressor Stations		
Dry-seal		
Gathering and Boosting Stations	No requirement	Volumetric flow rate of 3 scfm
Natural Gas Processing Plants		
Transmission and Storage Compressor Stations		
Liquids Unloading		
Well Sites	No requirement	Zero emissions or best management practices[d]
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

[a] Well sites and compressor stations on the Alaska North Slope are subject to Annual OGI monitoring only.
[b] Specifically, the affected source is natural gas-driven controllers that vent to the atmosphere.
[c] 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.
[d] The proposed 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 Requirements under the Proposed Option

	Presumptive Standards of Performance	
Source	**In the Baseline**	**Under the Proposal**
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
Gathering and Boosting Stations	No requirement	Methane emission rate of zero
Pneumatic Controllers[b]		
Well Sites	Pre-OOOO: No requirement Post-OOOO: Natural gas bleed rate no greater than 6 scfh	Methane emission rate of zero[c]
Gathering and Boosting Stations	Pre-OOOO: No requirement Post-OOOO: Natural gas bleed rate no greater than 6 scfh	Methane emission rate of zero[c]
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[c]
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

Centrifugal Compressors		
Wet-seal		
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		
Dry-seal		
Gathering and Boosting Stations	No requirement	Volumetric flow rate of 3 scfm
Natural Gas Processing Plants		
Transmission and Storage Compressor Stations		
Liquids Unloading		
Well Sites	No requirement	Zero emissions or best management practices[d]
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	

[a] Well sites and compressor stations on the Alaska North Slope are subject to Annual OGI monitoring only.
[b] Specifically, the affected source is natural gas-driven controllers that vent to the atmosphere.
[c] 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.
[d] The proposed 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 proposed 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 due to the unpredictable nature of super-emission events, resulting in a lack of specific data on their frequency, intensity, and cost to mitigate. We note that our estimates may undercount the emissions reductions achieved by this rule, as well as costs, because our analysis does not fully account for cost-effective opportunities to prevent or quickly correct super-emitter emissions events. Though we are not currently able to quantify the emissions reductions likely to result from preventing or more quickly mitigating super-emitter emissions events, we note that the information presented in Appendix D includes model simulations suggesting that covering large emitters could "significantly impact[] the expected emissions from the fugitive emission program."[20] Other requirements that we do not attempt to quantify regulatory impacts for in this RIA include emissions control requirements for associated gas from oil wells, and storage vessel control requirements at centralized production facilities (CPFs) and in the gathering and boosting segment. While we expect the impacts from the associated gas and storage vessels at CPFs provisions to be small relative to the overall impacts of the proposal, we do not expect them to be insignificant, and quantifying their impacts is a priority for the final rule. 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 the proposal; 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.[21] To project activity data for regulated facilities, we first project activity data for oil and 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 EPA's Greenhouse Gas Inventory (GHGI), regulated facilities are apportioned to sites across all industry segments.[22] We assume

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[20] As stated, some of the model simulations in Appendix D suggest that large-emitters could significantly impact the estimated emissions reductions; however, those simulations are not directly related to the definition of "super-emitter" included in this proposal, thus the emissions and emission reductions cannot be used to directly assess the emissions or emission reductions related to the proposed super-emitter program. The model simulations relied on information of large emissions from a single basin (Permian), and available data suggest that the frequency of these events may vary significantly across different production basins, which could lead to significant uncertainty if the emission reductions were applied nationwide.

[21] Regulated facilities include well site fugitives, 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, and storage vessels.

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

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 proposed NSPS OOOOb and EG OOOOc from 2023 to 2035. The initial analysis year is 2023 as we assume the proposed rule will be finalized early in that year. The NSPS OOOOb will take effect immediately and impact sources constructed after publication of the proposed rule. 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 three years, and so EG OOOOc impacts will begin in 2026. The final analysis year is 2035, which allows us to provide ten years of impacts after the EG OOOOc is assumed to take effect.

While it would be desirable to analyze impacts beyond 2035, 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 infeasible. 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.

2.2.1 Activity Data Projections

To construct the activity data projections used in this analysis, we rely on historical data from the Greenhouse Gas Inventory (GHGI),[23] industry data collected by 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,[24] and projections from the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO).[25] 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 the proposed 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 proposed 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 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)

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[23] 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.

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

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

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 2022, while V4 is subdivided into separate vintages for each year from 2023, when the NSPS OOOOb is assumed to take effect, through 2035. In the case of well sites only, V1 is further subdivided into sites constructed prior to 2000 and sites constructed from 2000 on.

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) (compressor stations), 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);[26] 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).

[26] 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.

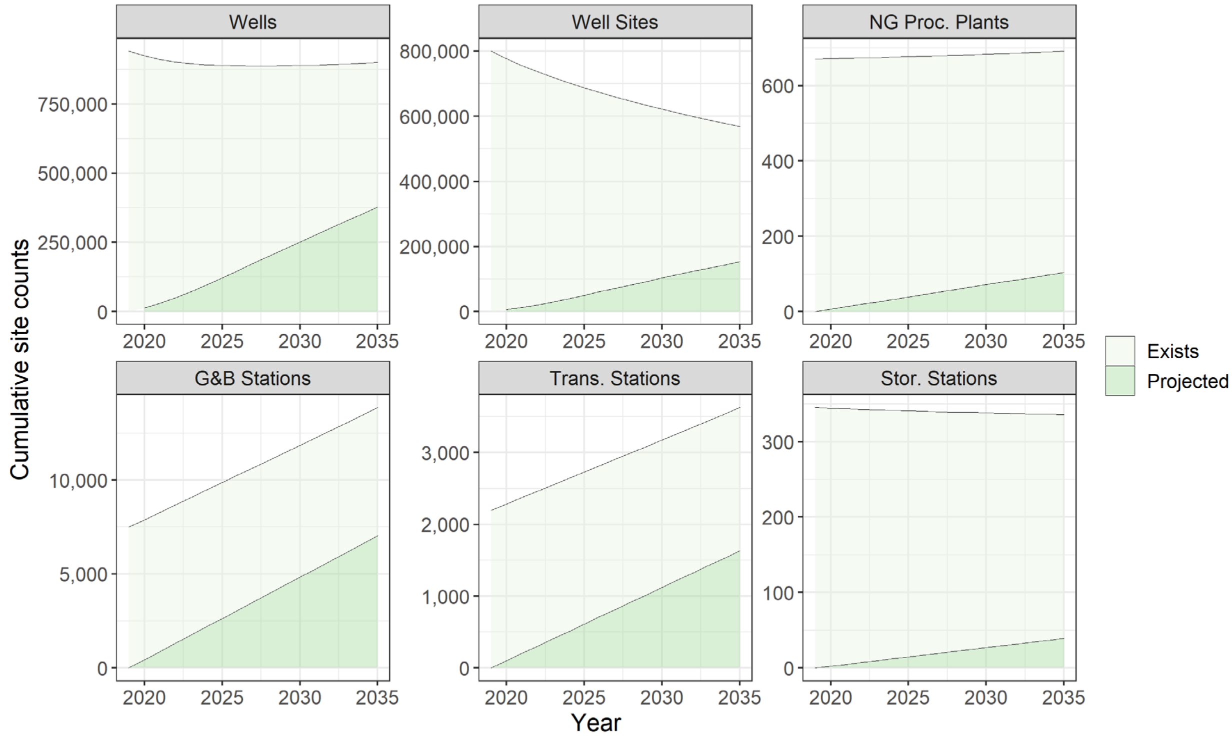

Figure 2-1 Projections of Cumulative Site Counts by Site Type and Vintage

(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 as we assume that it is the most recent year with comprehensive data coverage due to reporting lags.

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 assigned as oil or gas based on gas-to-oil ratios (GOR).[27] 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.[28]

Using the projections, we aggregate entities into representative groups for each year (2019–2035). For well sites, each group characterized by a unique combination of state, 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.[29] Each group includes total counts of sites, oil and gas wells, and oil and gas production. Likewise, the well and lease entities for which we don't 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 national-level proportions derived from the subset of data with well site identifiers, stratifying over site types, vintage bins, and initial production rate bins. 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.[30]

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

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[27] If GOR > 100,000 mcf per bbl, then the well is designated as a gas well, otherwise, it is designated as an oil well.
[28] 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 following decline rate assumptions:

	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%

[29] Sites are grouped the four production rate bins, based on the average BOE/d per well at the site, described in footnote 27.
[30] The dataset, along with the analysis code used to estimate impacts, can be found in the docket.

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 2035 based on the relative proportions of wells in each group, with production for each vintage projected through 2035.

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.[31] 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).

(b) Compressor Stations

We project compressor stations for three segments (gathering and boosting, transmission, and storage) using data from GHGI; the approach for all three segments is analogous.[32] 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 constructed in 2016. This yields an estimate of the average number of V3 stations added per year

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[31] 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.

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

through the base year, and we assume new stations are added at that same rate beyond the base year. New stations assumed to be constructed in 2020 and 2021 are assigned to V3, while all estimated new stations beyond 2021 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 three vintages (2016–2019, 2020, and 2021), with the latter two 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 2022–2035.

(c) Natural Gas Processing Plants

To construct base year activity data counts for natural gas processing plants, we leverage data from both the GHGI and HIFLD.[33] 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.

[33] 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.

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 proposed 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 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 proposed 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 EPA's 2016 Information Collection Request (ICR) for the Oil and Natural Gas Industry (hereafter, 2016 ICR).[34] The data captured a survey of 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 six equipment categories for all combinations of oil and gas sites and single and multi-well sites.[35] We also

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[34] 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.

[35] The equipment categories are: (1) no equipment or tanks; (2) no equipment with storage tanks; (3) one piece of major equipment without tanks; (4) one piece of major equipment with tanks; (5) more than one piece of major equipment without tanks; and (6) more than one piece of major equipment with tanks. Since we estimate proportions for all combinations of site type (oil, gas) and well count bin (single, multi), there are 24 possibilities in total.

calculate, for each combination of equipment category, site type, and well count bin average equipment and tank counts per oil and gas well. See Section A.1 in the appendix for a detailed discussion of how the ICR data is processed to construct equipment bin proportions and average equipment counts.

The equipment category proportions and average counts generated from the ICR are applied to the well site projections and scaled to match per-well equipment factors from the GHGI from the base year. The calibration entails a series of steps, beginning with the imputation of equipment (process heaters and heater-treaters) not surveyed in the 2016 ICR. Using site-level survey data provided by the American Petroleum Institute (API),[36] we estimate the proportion of sites that have exactly one piece of major equipment captured in the ICR (separators, compressors, and dehydrators) that also have heaters or heater-treaters and use this to adjust the equipment category proportions estimated using the ICR data. The API survey data is also used to estimate the average number of heaters and heater-treaters per gas and oil well for oil/gas and single/multi-well sites. These estimates, along with the ICR average equipment estimates, are applied to the well site group dataset for the base year, and then the per-well equipment counts are scaled uniformly across equipment categories and site types such that the aggregate per-well equipment counts across all well sites match the GHGI in 2019. As part of this process, we also calculate the number of headers per oil well (only at sites with major equipment) and meters/piping per gas well (at all sites) such that the per-well counts of that equipment also matches the GHGI in 2019. More details on how the API survey data is used and the calibration steps is available in Section A.2 in the appendix.

The equipment category proportions are illustrated in Table 2-4 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. Importantly, we assume that equipment is assigned to well sites based on either base year production levels (for sites in the base year dataset) or first

[36] 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.

year production levels (for projected new construction beyond the base year) and *does not* change as production declines.

Fugitive emissions monitoring requirements differ across the equipment bins captured in the table. In the analysis of the proposed 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 2-4 Distribution of Well Sites in Equipment Bins

Site Bin	Proportions in the base year (2019)	Proportions in the projected years
Natural Gas		
Single wellhead		
Wellhead only	34%	33%
One piece of major equipment, including tank batteries	44%	43%
More than one piece of major equipment, including tank batteries	16%	15%
Multi-wellhead		
Wellhead only	0.13%	0.16%
One piece of major equipment, including tank batteries	5.0%	7.8%
More than one piece of major equipment, including tank batteries	0.49%	0.58%
Oil		
Single wellhead		
Wellhead only	51%	45%
One piece of major equipment, including tank batteries	31%	30%
More than one piece of major equipment, including tank batteries	8.6%	7.3%
Multi-wellhead		
Wellhead only	0.6%	0.8%
One piece of major equipment, including tank batteries	7.2%	15%
More than one piece of major equipment, including tank batteries	1.3%	1.7%

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".[37]

(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, scaling the estimates such that the aggregate controller-per-site counts match the GHGI in 2019. 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 from the proposal for that segment and affected facility.

To estimate controller counts at well sites, we proceed in three steps. First, we multiply, for each well site group, equipment counts per oil and gas well by controller-per-equipment factors presented in the Supporting Information of Zavala-Araiza et al. (2017).[38] Second, we uniformly scale the resulting controller counts per well across all sites in the base year such that they match, in aggregate, the GHGI controller per-well counts in 2019 for both oil and gas wells. Finally, 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

[37] See page 6 of Chapter 10 of the November 2021 TSD.
[38] Using data from Allen et al. (2015), the authors estimate 0.42 controllers per wellhead, 1 controller per separator at gas sites without liquids, 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 dehydrators.

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.

(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).[39] 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.[40]

(e) Centrifugal Compressors

The GHGI contains estimates of the number of wet-seal and dry-seal centrifugal compressors in the gathering and boosting, processing, and transmission segments. For the transmission and storage segments, 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,

[39] 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.
[40] This assumption is based on data summarized on page 28 of Zimmerle et al. (2019).

wet and dry seal compressors are allocated on a per-station basis such that the estimated counts of wet and dry seal compressors per station in 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,[41] 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 more accurately, we divide natural gas wells into two categories: those with plunger lifts and those without plunger lifts. The GHGI contains activity data for the number of wells in each category 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 wells perform manual unloading.[42] Finally, we convert from wells to events by multiplying by events per well values from the BSER analysis.[43]

(g) 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 are an area of ongoing development. As described in Section 2.2.1.1(a), proportions of sites with tanks and tank counts per oil and 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

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[41] Ibid.
[42] 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.
[43] 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.

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 proposed rule are presented in Table 2-5. 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 2-5 Projection of Incrementally Impacted Affected Facilities under the Proposed NSPS OOOOb and EG OOOOc Option, 2023 to 2035

Year	Well Site Fugitives	Gathering and Boosting Station Fugitives	Transmission and Storage Compressor Station Fugitives	Natural Gas Processing Plants Leaks	Pneumatic Devices	Reciprocating Compressors	Centrifugal Compressors	Liquids Unloading	Storage Vessels
2023	14,000	0	0	23	76,500	2,700	320	6,800	2,100
2024	22,000	0	0	34	115,500	4,000	480	11,000	3,200
2025	31,000	0	0	45	167,600	5,400	650	15,000	4,500
2026	520,000	5,200	1,900	1,200	1,400,000	36,000	4,800	260,000	5,800
2027	510,000	5,200	1,900	1,200	1,500,000	38,000	4,900	260,000	7,000
2028	500,000	5,200	1,900	1,200	1,500,000	39,000	5,100	260,000	8,300
2029	490,000	5,100	1,900	1,200	1,500,000	40,000	5,200	250,000	9,600
2030	480,000	5,100	1,800	1,200	1,499,000	41,000	5,400	250,000	11,000
2031	480,000	5,000	1,800	1,200	1,499,000	42,000	5,500	250,000	12,000
2032	470,000	5,000	1,800	1,200	1,498,000	43,000	5,600	250,000	13,000
2033	460,000	5,000	1,800	1,200	1,497,000	45,000	5,800	250,000	15,000
2034	450,000	4,900	1,800	1,200	1,497,000	46,000	5,900	240,000	16,000
2035	440,000	4,900	1,800	1,200	1,496,000	47,000	6,000	240,000	17,000

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 proposed rule are derived from the technical analyses underpinning the BSER determination. In some cases, we define our affected facilities' projections to be identical to the model plants found in the Supplemental 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.

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 Supplemental 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.[44] Processing plant leaks are divided into four different model plants: all combinations of large and small plants, and VOC and non-VOC service.[45] Reciprocating compressors are represented by a single model plant for each of the gathering and boosting, processing, transmission, and storage segments.[46] 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.[47]

The methodology for projecting of costs and emissions impacts from OGI monitoring programs of different frequencies uses counts of major equipment in well site groups (described in Section 2.2.1.2(a)) and the results of the BSER technical analysis performed in support of this action. The BSER analysis uses simulations produced by the Fugitive Emissions Abatement

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[44] 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.
[45] 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).
[46] 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).
[47] See Chapter 2 of the Supplemental 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).

Simulation Tool (FEAST), which are descriped in Appendix D.[48] 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 (MW1), a multi-well site with no major equipment (MW2), a multi-well site with a separator, an in-line heater, and a dehydrator (MW3), and a multi-well site with a separator, an in-line heater, a dehydrator, and a controlled storage tank battery (MW4)) and five OGI frequencies (annual, semiannual, quarterly, bimonthly, and monthly). Each model well site contains an assumed number of components based on the number of wells and the type of major equipment present at the site. A FEAST simulation for a model well site produces 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. For the impacts analysis presented in this document, we used emissions rates and control efficiencies generated from the FEAST runs without large emission events described in Section 4 of the FEAST memo (see Appendix D). As noted on pages 23–24 in Section 5 of the FEAST memo, incorporating large emission events could change the results substantially.

The calculation of 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). Next, 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.[49] Third, an emissions factor per component is determined based on the FEAST simulation. The emissions factor per component is calculated by averaging baseline emissions per component in the absence of OGI monitoring for each model well site in the FEAST simulations. This emissions factor per component is multiplied by the number of components per well site and summed over well sites to determine baseline emissions for a well site group. Fourth, 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 MW1, multi-well sites with no major equipment are matched to MW2, and all

[48] See also Chapter 5 of the Supplemental TSD for details on the FEAST modeling and costs and emissions reductions associated with OGI monitoring at well sites.
[49] See https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98.

other sites are matched to MW3. 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.

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,[50] 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.[51] Emissions factors for low-bleed, high-bleed, and intermittent bleed pneumatic controllers (all segments except processing) and pneumatic pumps (production[52] and gathering and boosting) from the GHGI 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 calculate site-wide emissions, pre- and post-control. 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 the 2019 dollar year (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

[50] 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.
[51] See Chapter 3 of the Supplemental 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).
[52] Specifically, the chemical injection pump emissions factor is used.

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.[53]

For the proposed rule, as well as the regulatory alternatives specified in Section 2.6, 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 maintence 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 and gathering and boosting stations. This assumption likely overestimates the costs of compliance somewhat, since sites with access to grid electricity would not incur the costs for the solar PV panels and batteries. In contrast, we assume that transmission and storage compressor stations are grid-connected, with the former complying through installation of electronic controllers and the latter, due to the large number of controllers assumed to be located at the model plant, complying through installation of a compressed air system.

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 Supplemental Proposal TSD. However, whereas the BSER analysis evaluates a range of emissions reductions levels associated with the proposed option, this

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[53] 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.

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.[54]

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.[55] 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 proposal 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 is assumed to take effect (2026) for EG OOOOc-affected facilities.[56] For sites subject to control requirements, we assume that 95% 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.[57]

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

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[54] 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.

[55] 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.

[56] 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.

[57] 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.

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 proposed regulation.

Specifically, we assume that California and Colorado have requirements at least as stringent as those in the proposed rule for compressor station fugitives; natural gas processing plant leaks; pneumatic controllers; pneumatic pumps in the production and gathering and boosting segments; pre-OOOO reciprocating and wet seal centrifugal compressors in the gathering and boosting and processing segments; and storage vessels. In addition, we assume California has requirements at least as stringent as those in the proposed rule for pre-OOOO reciprocating and wet seal centrifugal compressors in the transmission and storage segments; and post-OOOO reciprocating and wet seal centrifugal compressors in all segments. We assume that Colorado has requirements at least as stringent as those in the proposed 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 proposed 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 Enverus was used to calculate the proportions of natural gas processing plants and compressor stations 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 2-6 summarizes the emissions reductions associated with the proposed 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 a global warming potential of 25.

Table 2-6 Projected Emissions Reductions under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035

	Emissions Changes			
Year	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO_2 Eq. using GWP=25)**
2023	140,000	61,000	2,300	3,300,000
2024	220,000	91,000	3,500	5,000,000
2025	300,000	120,000	4,600	6,900,000
2026	3,500,000	920,000	37,000	79,000,000
2027	3,500,000	930,000	38,000	79,000,000
2028	3,500,000	930,000	38,000	79,000,000
2029	3,500,000	940,000	38,000	79,000,000
2030	3,500,000	940,000	38,000	79,000,000
2031	3,500,000	950,000	38,000	79,000,000
2032	3,500,000	950,000	38,000	80,000,000
2033	3,500,000	950,000	39,000	80,000,000
2034	3,500,000	960,000	39,000	80,000,000
2035	3,500,000	960,000	39,000	80,000,000
Total	36,000,000	9,700,000	390,000	810,000,000

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 proposed 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 2–5 of the Supplemental TSD and Chapters 7 and 10–11 of the November 2021 TSD for details on the proportion of recovered emissions associated with the compliance options.

Table 2-7 summarizes the increase in natural gas recovery and the associated revenue. The AEO2022 projects Henry Hub natural gas prices rising from \$3.49/MMBtu in 2023 to \$3.64/MMBtu in 2035 in 2021 dollars.[58] 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

[58] Available at: https://www.eia.gov/outlooks/aeo/excel/aeotab_13.xlsx. Accessed July 25, 2022.

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 1.037 MMBtu equals 1 Mcf.[59] Incorporating these adjustments, wellhead natural gas prices are assumed to rise from $3.09/Mcf in 2023 to $3.22/Mcf in 2035.

Table 2-7 Projected Increase in Natural Gas Recovery under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035

Year	Increase in Gas Recovery (Bcf)	Increased Revenue (millions 2019$)
2023	8.0	$25
2024	12	$35
2025	17	$45
2026	200	$520
2027	200	$540
2028	200	$570
2029	200	$590
2030	200	$610
2031	200	$630
2032	200	$630
2033	200	$650
2034	200	$650
2035	200	$650

Note: Values rounded to two significant figures.

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

[59] For MMbtu-Mcf conversion factor, see https://www.eia.gov/outlooks/aeo/data/browser/#/?id=20-AEO2021&cases=ref2021&sourcekey=0. Accessed October 7, 2021.

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 2-8 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, and storage vessels, 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, and storage vessels.

Note that Table 2-8 shows a pulse of capital expenditures in 2026, the year the RIA assumes to be the compliance year for the proposed EG OOOOc. In practice, however, the proposed requirements give States and sources the flexibility to spread these installations over a period of up to three years, or the 2025 to 2027 period. 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.

Table 2-8 Projected Compliance Costs under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions 2019$)

	Compliance Costs				
Year	**Capital Costs**	**Operating and Maintenance Costs**	**Annualized Costs**	**Increased Revenue from Product Recovery**	**Annualized Costs with Increased Revenue from Product Recovery**
2023	$480	$66	$120	$25	$95
2024	$270	$100	$190	$35	$150
2025	$290	$140	$260	$45	$210
2026	$12,000	$1,300	$2,800	$520	$2,200
2027	$310	$1,300	$2,700	$540	$2,200
2028	$300	$1,300	$2,700	$570	$2,200
2029	$320	$1,300	$2,700	$590	$2,100
2030	$660	$1,300	$2,700	$610	$2,000
2031	$310	$1,300	$2,700	$630	$2,000
2032	$330	$1,300	$2,700	$630	$2,000
2033	$320	$1,300	$2,700	$650	$2,000
2034	$860	$1,400	$2,700	$650	$2,000
2035	$340	$1,400	$2,700	$650	$2,000

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 3.3 years in the processing segment, 3.8 years in the gathering and boosting and transmission segments, and 4.4 years in the storage segment.[60] The capital costs in each year outlined in Table 2-8 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.

[60] For the purposes of assigning unannualized capital costs of subsequent replacements to years, we round the lifetimes for rod-packing to the nearest whole number.

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 this proposal, over 80 percent of revenue from the sale of captured natural gas is projected to be earned by operators in the production and processing segments 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 transmission and storage segment, 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, 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.

We now present the compliance costs of the proposed NSPS OOOOb and EG OOOOc in a PV framework. The stream of the estimated costs for each year from 2023 through 2035 is discounted back to 2021 using 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 2-9 shows the undiscounted stream of costs for each year from 2023 through 2035 due to the proposed 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 2-9 Undiscounted Projected Compliance Costs under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions 2019$)

Year	Capital Costs	Annual Operating Costs	Total Costs (w/o Revenue)	Revenue from Product Recovery	Total Costs (with Revenue)
2023	$480	$66	$550	$25	$520
2024	$270	$100	$370	$35	$340
2025	$290	$140	$430	$45	$390
2026	$12,000	$1,300	$13,000	$520	$12,000
2027	$310	$1,300	$1,600	$540	$1,100
2028	$300	$1,300	$1,600	$570	$1,000
2029	$320	$1,300	$1,600	$590	$1,000
2030	$660	$1,300	$2,000	$610	$1,400
2031	$310	$1,300	$1,600	$630	$1,000
2032	$330	$1,300	$1,700	$630	$1,000
2033	$320	$1,300	$1,700	$650	$1,000
2034	$860	$1,400	$2,200	$650	$1,600
2035	$340	$1,400	$1,700	$650	$1,100

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

Table 2-10 shows the discounted stream of costs discounted to 2021 using a 3 and 7 percent discount rate. The PV of the stream of costs discounted to 2021 using a 3 percent discount rate is $19 billion, with an EAV of $1.8 billion per year. The PV of the stream of costs discounted to 2021 using a 7 percent discount rate is $15 billion, with an EAV of $1.8 billion per year.

Table 2-10 Discounted Projected Costs under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions 2019$)

	3 Percent			7 Percent		
Year	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)
2023	$100	$23	$80.0	$100	$22	$83.0
2024	$160	$32	$120.0	$150	$28	$120.0
2025	$210	$40	$170.0	$200	$34	$160.0
2026	$2,200	$450	$1,700	$2,000	$370	$1,600
2027	$2,100	$450	$1,600	$1,800	$360	$1,500
2028	$2,000	$460	$1,600	$1,700	$360	$1,400
2029	$2,000	$470	$1,500	$1,600	$340	$1,200
2030	$1,800	$470	$1,400	$1,400	$330	$1,100
2031	$1,800	$470	$1,300	$1,400	$320	$1,000
2032	$1,700	$460	$1,300	$1,300	$300	$960
2033	$1,700	$450	$1,200	$1,200	$290	$890
2034	$1,600	$440	$1,200	$1,100	$270	$840
2035	$1,600	$430	$1,200	$1,000	$250	$780
PV	**$19,000**	**$4,600**	**$14,000**	**$15,000**	**$3,300**	**$12,000**
EAV	**$1,800**	**$440**	**$1,400**	**$1,800**	**$390**	**$1,400**

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 proposal with the results of two alternative regulatory scenarios, one less stringent and one more stringent than the proposed rule. The alternative scenarios focus on the sources that account for the largest number of estimated emissions reductions of methane and/or VOC for the proposed rule: well site fugitives and pneumatic devices at well sites.

The alternative scenarios are summarized in Table 2-11. 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 over estimate of the impacts of the proposal and more stringent scenarios. In the less stringent scenario, we estimate the impacts of not including the AVO requirements for fugitive emissions monitoring at well sites, extending the current NSPS of an emissions limit for continuous-bleed controllers to pre-OOOO (for well sites and gathering and boosting stations) or pre-OOOOa (for transmission and storage compressor station) sources rather than requiring zero emitting controllers, and omitting requirements for pneumatic pumps rather than requiring zero emitting pumps. 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. These alternatives reflect key regulatory design alternatives that the EPA grappled with while developing the proposal.

Table 2-11 Summary of Regulatory Alternatives

Source	Applicable NSPS	NSPS Baseline	Less Stringent	Proposal	More Stringent
Fugitive Emissions at Well Sites					
Wellhead only, single wellsite	OOOOa	No requirement	No requirement	Quarterly AVO	Quarterly AVO
Wellhead only, multiple well site	OOOOa	No requirement	Semiannual OGI	Quarterly AVO + Semiannual OGI	Quarterly AVO + Semiannual OGI
Single well site with a single price of major equipment and no tank battery	OOOOa	Semiannual OGI	No requirement	Quarterly AVO	Quarterly AVO + Semiannual OGI
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	OOOOa	Semiannual OGI	Quarterly OGI	Bimonthly AVO + Quarterly OGI	Bimonthly AVO + Quarterly OGI
Pneumatic Controllers					
Well Sites and Gathering and Boosting Stations	OOOO	Natural gas bleed rate no greater than 6 scfh	Natural gas bleed rate no greater than 6 scfh	Zero emissions	Zero emissions
Transmission and Storage Compressor Stations	OOOOa	Natural gas bleed rate no greater than 6 scfh	Natural gas bleed rate no greater than 6 scfh	Zero emissions	Zero emissions
Pneumatic Pumps					
Well Sites	OOOOa	No requirement[a]	No requirement	Zero emissions	Zero emissions
Gathering and Boosting Stations	None	No requirement	No requirement	Zero emissions	Zero emissions

[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 over estimate of the impacts of the proposal and more stringent scenarios.

A comparison of estimated costs and emissions reductions is presented in Table 2-12 for three years: 2023 (the first year of NSPS OOOOb impacts), 2026 (the first year of EG OOOOc impacts), and 2035 (the last year of analysis). Overall, the table demonstrates that we estimate the impacts of EG OOOOc to be much greater than those of the NSPS OOOOb for all regulatory alternatives. By the time the EG OOOOc is assumed to begin having an effect in 2026, we estimate that the less stringent option would result in roughly one-third of the methane and VOC emissions reductions of the proposed option, while reducing costs by about half. On the other hand, we estimate that the more stringent option would result in slightly more methane and VOC emissions reductions and slightly higher costs than the proposed option. Note that since the EG OOOOc regulates emissions of methane, additional benefits to the regulation result from associated reductions in VOC emissions.

Table 2-12 Comparison of Regulatory Alternatives in 2023, 2026, and 2035 for the Proposed NSPS OOOOb and EG OOOOc (millions 2019$)

	Regulatory Alternative		
	Less Stringent	**Proposal**	**More Stringent**
		Total Impacts, 2023	
Emissions reductions			
Methane (short tons)	30,000	140,000	140,000
VOC (short tons)	30,000	61,000	61,000
Costs			
Annualized Costs without Product Recovery (3%)	$76	$110	$110
Annualized Costs with Product Recovery (3%)	$72	$85	$86
		Total Impacts, 2026	
Emissions reductions			
Methane (short tons)	1,300,000	3,500,000	3,500,000
VOC (short tons)	320,000	920,000	930,000
Costs			
Annualized Costs without Product Recovery (3%)	$1,200	$2,500	$2,600
Annualized Costs with Product Recovery (3%)	$970	$2,000	$2,100
		Total Impacts, 2035	
Emissions reductions			
Methane (short tons)	1,200,000	3,500,000	3,500,000
VOC (short tons)	330,000	960,000	970,000
Costs			
Annualized Costs without Product Recovery (3%)	$1,300	$2,400	$2,500
Annualized Costs with Product Recovery (3%)	$1,100	$1,800	$1,800

3 BENEFITS

The proposed NSPS OOOOb and EG OOOOc are projected to reduce methane, VOC, and HAP emissions.[61] The total emissions reductions over the 2023–2035 period are estimated to be about 36 million short tons of methane, 9.7 million tons of VOC, and 0.39 million tons of HAP. The decrease in methane emissions in CO_2-equivalent (CO_2 Eq.) terms is estimated to be about 810 million metric tons using a global warming potential of 25.

We monetize the impacts of methane reductions in this RIA. We estimate the climate benefits under the proposal using interim estimates of the social cost of methane (SC-CH_4), as presented in Section 3.2.

In addition to presenting monetized estimates of impacts from methane reductions, we also provide a qualitative discussion of potential climate, human health, and welfare impacts of emissions reductions we are unable to quantify and monetize. Table 3-1 summarizes the quantified and unquantified benefits in this analysis. We also present a supplemental illustrative screening analysis of quantified and monetized ozone-related health impacts of VOC reductions based on a national benefit-per-ton methodology in Appendix C. Additional benefits to EG OOOOc, which regulates methane emissions, result from associated reductions in VOC emissions.

[61] Some control techniques of the proposed action, such as routing emission to combustion devices, are also anticipated to have minor disbenefits resulting from secondary emissions of carbon dioxide (CO2), nitrogen oxides (NOX), PM, carbon monoxide (CO), and total hydrocarbons (THC).

Table 3-1 Climate and Human Health Effects of the Projected Emissions Reductions from this Proposal

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[62]	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[63]	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[b]
	Metabolic effects (e.g., diabetes)	—	—	Ozone ISA[b]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[b]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[b]
	Reproductive and developmental effects	—	—	Ozone ISA[b]
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
	Heart attacks (age > 18)	—	—	PM ISA

[62] We present a supplemental illustrative analysis of quantified and monetized ozone-related health impacts of VOC reductions based on a national benefit-per-ton methodology in Appendix C.
[63] Ibid.

Category	Effect	Effect Quantified	Effect Monetized	More Information
Nonfatal morbidity from exposure to $PM_{2.5}$	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
	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[b]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[b]
	Other nervous system effects (e.g., autism, cognitive decline, dementia)	—	—	PM ISA[b]
	Metabolic effects (e.g., diabetes)	—	—	PM ISA[b]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA[b]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[b]

Category	Effect	Effect Quantified	Effect Monetized	More Information
Incidence of morbidity from exposure to HAP	Effects associated with exposure to hazardous air pollutants such as benzene	—	—	ATSDR, IRIS[c,d]

[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] Not quantified due to data availability limitations and/or because current evidence is only suggestive of causality.
[c] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.
[d] 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 proposed NSPS OOOOb and EG OOOOc over the 2023–2035 period. We present methane emissions in both short tons and CO_2 Eq. using a global warming potential of 25. 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 Emissions under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035

Year	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)
2023	140,000	61,000	2,300	3,300,000
2024	220,000	91,000	3,500	5,000,000
2025	300,000	120,000	4,600	6,900,000
2026	3,500,000	920,000	37,000	79,000,000
2027	3,500,000	930,000	38,000	79,000,000
2028	3,500,000	930,000	38,000	79,000,000
2029	3,500,000	940,000	38,000	79,000,000
2030	3,500,000	940,000	38,000	79,000,000
2031	3,500,000	950,000	38,000	79,000,000
2032	3,500,000	950,000	38,000	80,000,000
2033	3,500,000	950,000	39,000	80,000,000
2034	3,500,000	960,000	39,000	80,000,000
2035	3,500,000	960,000	39,000	80,000,000
Total	36,000,000	9,700,000	390,000	810,000,000

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, 2021), 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.[64] 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. 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 (U.S. EPA, 2021d).

We estimate the climate benefits of CH_4 emissions reductions expected from this proposed rule using the SC-CH_4 estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* published in February 2021 by the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) (IWG, 2021). The SC-CH_4 is the monetary value of the net harm to society associated with a marginal increase in emissions in a given year, or the benefit of avoiding that increase. In principle, SC-CH_4 includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and 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 emissions of the gas in question by one metric ton. The SC-CH_4 is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CH_4 emissions. As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, the EPA agrees that the interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the

[64] 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.

latest, peer-reviewed science. While the IWG's SC-GHG review and updating process under EO 13990 continues, in Appendix B of this RIA the EPA presents a sensitivity analysis of the monetized climate benefits using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017).

The SC-CH_4 estimates presented in the February 2021 SC-GHG TSD were developed over many years, using transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices was established to ensure that agencies had access to the best available information when quantifying the benefits of reducing CO_2 emissions in benefit-cost analyses. The IWG published SC-CO_2 estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs were run using a common set of input assumptions in each model for future population, economic, and CO_2 emissions growth, as well as equilibrium climate sensitivity (ECS) — a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM.[65] In August 2016 the IWG published estimates of the social cost of methane (SC-CH_4) and nitrous oxide (SC-N_2O) using methodologies that are consistent with the methodology underlying the SC-CO_2 estimates. The modeling approach that extends the IWG SC-CO_2 methodology to non-CO_2 GHGs has undergone multiple stages of peer review. The SC-CH_4 and SC-N_2O estimates were developed by Marten, Kopits, Griffiths, Newbold, and Wolverton (2015) and underwent a standard double-blind peer review process prior to journal publication. These estimates were applied in regulatory impact analyses of EPA proposed rulemakings with CH_4

[65] Dynamic Integrated Climate and Economy (DICE) 2010 (Nordhaus, 2010), Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8 (Anthoff & Tol, 2013a, 2013b), and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009 (Hope, 2013). Dynamic Integrated Climate and Economy (DICE) 2010 (Nordhaus, 2010), Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8 (Anthoff & Tol, 2013a, 2013b), and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009 (Hope, 2013).

and N_2O emissions impacts.[66] The EPA also sought additional external peer review of technical issues associated with its application to regulatory analysis. Following the completion of the independent external peer review of the application of the Marten et al. (2015) estimates, the EPA began using the estimates in the primary benefit-cost analysis calculations and tables for a number of proposed rulemakings in 2015 (EPA 2015b, 2015c). The EPA considered and responded to public comments received for the proposed rulemakings before using the estimates in final regulatory analyses in 2016.[67] In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*, and recommended specific criteria for future updates to the SC-CO_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). Shortly thereafter, in March 2017, President Trump issued EO 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to "ensure" SC-GHG estimates used in regulatory analyses "are consistent with the guidance contained in OMB Circular A-4", "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (EO 13783, Section 5(c)). Benefit-cost analyses following EO 13783, including the benefit-cost analysis for the Oil and Natural Gas Technical Reconsideration and Policy Review RIA,[68] (U.S. EPA, 2020c) used SC-GHG estimates that attempted to focus on the specific share of physical climate change damages in the U.S. as captured by the models (which did not reflect many pathways by which climate impacts affect the welfare of U.S. citizens and residents) and were calculated using two default discount rates

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[66] The SC-CH_4 and SC-N_2O estimates were first used in sensitivity analysis for the Proposed Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles–Phase 2 (U.S. EPA, 2015).
[67] See IWG (2016b) for more discussion of the SC-CH_4 and SC-N_2O and the peer review and public comment processes accompanying their development.
[68] The values used in the rule RIA were interim values developed under EO 13783 for use in regulatory analyses. EPA followed EO 13783 by using SC-CO_2 estimates reflecting impacts occurring within U.S. borders and 3% and 7% discount rates in our central analysis for the proposal RIA.

recommended by Circular A-4 (2003), 3 percent and 7 percent.[69] All other methodological decisions and model versions used in the SC-GHG calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued EO 13990, which established an IWG and directed the group to develop an update of the SC-GHG estimates that reflect the best available science and the recommendations of National Academies (2017). In February 2021, the IWG recommended the interim use of the most recent SC-GHG estimates developed by the IWG prior to the group being disbanded in 2017, adjusted for inflation (IWG, 2021). As discussed in the February 2021 TSD, the IWG's selection of these interim estimates reflected the immediate need to have SC-GHG estimates available for agencies to use in regulatory benefit-cost analyses and other applications that were developed using a transparent process, peer reviewed methodologies, and the science available at the time of that process. The February 2021 update also recognized the limitations of the interim estimates and encouraged agencies to use their best judgment in, for example, considering sensitivity analyses using lower discount rates. The IWG published a Federal Register notice on May 7, 2021, soliciting comment on the February 2021 TSD and on how best to incorporate the latest peer-reviewed scientific literature in order to develop an updated set of SC-GHG estimates. The EPA has applied the IWG's interim SC-GHG estimates in regulatory analyses published since the release of the February 2021 TSD, including in the November 2021 Proposal RIA, and is likewise using them in the primary benefit-cost analysis calculations in this supplemental proposal RIA. While the IWG's SC-GHG review and updating process under EO 13990 continues, the EPA also presents in Appendix B of this RIA a sensitivity analysis of the monetized climate benefits using SC-CH_4 estimates newly developed by EPA that incorporate recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017).

[69] EPA regulatory analyses under E.O. 13783 included sensitivity analyses based on global SC-GHG values and using a lower discount rate of 2.5%. OMB Circular A-4 (OMB, 2003) recognizes that special considerations arise when applying discount rates if intergenerational effects are important. In the IWG's 2015 *Response to Comments*, OMB—as a co-chair of the IWG—made clear that "Circular A-4 is a living document," that "the use of 7 percent is not considered appropriate for intergenerational discounting," and that "[t]here is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." OMB, as part of the IWG, similarly repeatedly confirmed that "a focus on global SCC estimates in [regulatory impact analyses] is appropriate" (IWG 2015).

The February 2021 SC-GHG TSD provides a complete discussion of the IWG's initial review conducted under EO 13990. In particular, the IWG found that the SC-GHG estimates used under EO 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG concluded that those estimates fail to capture many climate impacts that can affect the welfare of U.S. citizens and residents. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Those impacts are better captured within global measures of the social cost of greenhouse gases.

In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. A wide range of scientific and economic experts have emphasized the issue of reciprocity as support for considering global damages of GHG emissions. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to take significant steps to reduce emissions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis — and so benefit the U.S. and its citizens — is for all countries to base their policies on global estimates of damages.

As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, EPA agrees with this assessment and, therefore, in this proposed rule the EPA centers attention on a global measure of SC-CH_4. This approach is the same as that taken in EPA regulatory analyses over 2009 through 2016. A robust estimate of climate damages only to U.S. citizens and residents that accounts for the myriad of ways that global climate change reduces the net welfare of U.S. populations does not currently exist in the literature. As explained in the February 2021 TSD, existing estimates are both incomplete and an underestimate of total damages that accrue to the citizens and residents of the U.S. because they do not fully capture the regional interactions and spillovers discussed above, nor do they include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature, as discussed further below. The EPA, as a member of the IWG, will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of carbon impacts.[70]

Second, the IWG concluded that the use of the social rate of return on capital (7 percent under current OMB Circular A-4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC-GHG. Consistent with the findings of National Academies (2017) and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context (IWG, 2010, 2013, 2016a, 2016b), and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.[71] Furthermore, the damage estimates developed for use in the SC-GHG are estimated in consumption-equivalent terms, and so an application of OMB Circular A-4's guidance for regulatory analysis would then use the consumption discount rate to calculate the SC-GHG. As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, the EPA agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. EPA also notes that while OMB Circular A-4, as published in 2003, recommends using 3 percent and 7 percent discount rates as "default" values, Circular A-4 also reminds agencies that "different regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions." On discounting, Circular A-4 recognizes that "special ethical considerations arise when comparing benefits and costs across generations," and Circular A-4 acknowledges that analyses may appropriately "discount future costs and consumption benefits…at a lower rate than for

[70] For further discussion of EPA's focus on global estimates of SC-CH_4, see the supporting material for this entitled *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* (EPA 2022) in the docket.

[71] GHG emissions are stock pollutants, with damages associated with what has accumulated in the atmosphere over time, and they are long lived such that subsequent damages resulting from emissions today occur over many decades or centuries depending on the specific greenhouse gas under consideration. In calculating the SC-GHG, the stream of future damages to agriculture, human health, and other market and non-market sectors from an additional unit of emissions are estimated in terms of reduced consumption (or consumption equivalents). Then that stream of future damages is discounted to its present value in the year when the additional unit of emissions was released. Given the long time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages.

intragenerational analysis." In the 2015 Response to Comments on the Social Cost of Carbon for Regulatory Impact Analysis, OMB, EPA, and the other IWG members recognized that "Circular A-4 is a living document" and "the use of 7 percent is not considered appropriate for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." Thus, EPA concludes that a 7 percent discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this analysis. In this analysis, to calculate the present and annualized values of climate benefits, EPA uses the same discount rate as the rate used to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 SC-GHG TSD recommends "to ensure internal consistency — i.e., future damages from climate change using the SC-GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate." EPA has also consulted the National Academies' 2017 recommendations on how SC-GHG estimates can "be combined in RIAs with other cost and benefits estimates that may use different discount rates." The National Academies reviewed "several options," including "presenting all discount rate combinations of other costs and benefits with [SC-GHG] estimates."

While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC-GHG estimates, it recommends the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 SC-GHG TSD, the IWG has concluded that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values for use in benefit-cost analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the 95th percentile of estimates based on a 3 percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change, conditional on the 3 percent estimate of the discount rate. As explained in the February 2021 SC-GHG TSD, and EPA agrees, this update reflects the immediate need to have an operational SC-GHG for use in regulatory benefit-cost analyses and other applications that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

Table 3-3 summarizes the interim SC-CH_4 estimates across all the model runs for each discount rate for emissions occurring in 2023 to 2035. These estimates are reported in 2019 dollars but are otherwise identical to those presented in the IWG's 2016 TSD (IWG, 2016b). For purposes of capturing uncertainty around the SC-CH_4 estimates in analyses, the IWG's February 2021 SC-GHG TSD emphasizes the importance of considering all four of the SC-CH_4 values. 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 Interim Estimates of the Social Cost of CH_4, 2023–2035 (in 2019$ per metric ton CH_4)

	Discount Rate and Statistic			
Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2023	$740	$1,600	$2,100	$4,200
2024	$770	$1,700	$2,100	$4,400
2025	$790	$1,700	$2,200	$4,500
2026	$820	$1,700	$2,300	$4,600
2027	$850	$1,800	$2,300	$4,700
2028	$870	$1,800	$2,400	$4,900
2029	$900	$1,900	$2,400	$5,000
2030	$930	$1,900	$2,500	$5,100
2031	$960	$2,000	$2,500	$5,300
2032	$990	$2,000	$2,600	$5,400
2033	$1,000	$2,100	$2,700	$5,600
2034	$1,100	$2,200	$2,700	$5,700
2035	$1,100	$2,200	$2,800	$5,900

Source: Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990 (IWG, 2021).
Note: These SC-CH4 values are identical to those reported in the 2016 TSD (IWG, 2016b) 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 tonne CH4 and vary depending on the year of

CH4 emissions. This table displays the values rounded to the nearest dollar; the annual unrounded values used in the calculations in this RIA are available on OMB's website: https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/.

Figure 3-1 presents the quantified sources of uncertainty in the form of frequency distributions for the SC-CH_4 estimates for emissions in 2030. [72] The distribution of SC-CH_4 estimates reflect uncertainty in key model parameters such as the equilibrium climate sensitivity, as well as uncertainty in other parameters set by the original model developers. To highlight the difference between the impact of the discount rate and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-CH_4 estimates for each discount rate. As illustrated by the figure, the assumed discount rate plays a critical role in the ultimate estimate of the SC-CH_4. This is because GHG emissions today continue to impact society far out into the future, so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. As discussed in the February 2021 SC-GHG TSD, there are other sources of uncertainty that have not yet been quantified and are thus not reflected in these estimates.

[72] Although the distributions and numbers in Figure 3-1 are based on the full set of model results (150,000 estimates for each discount rate), for display purposes the horizontal axis is truncated with 0.029 percent of the estimates falling below the lowest bin displayed and 3 percent of the estimates falling above the highest bin displayed.

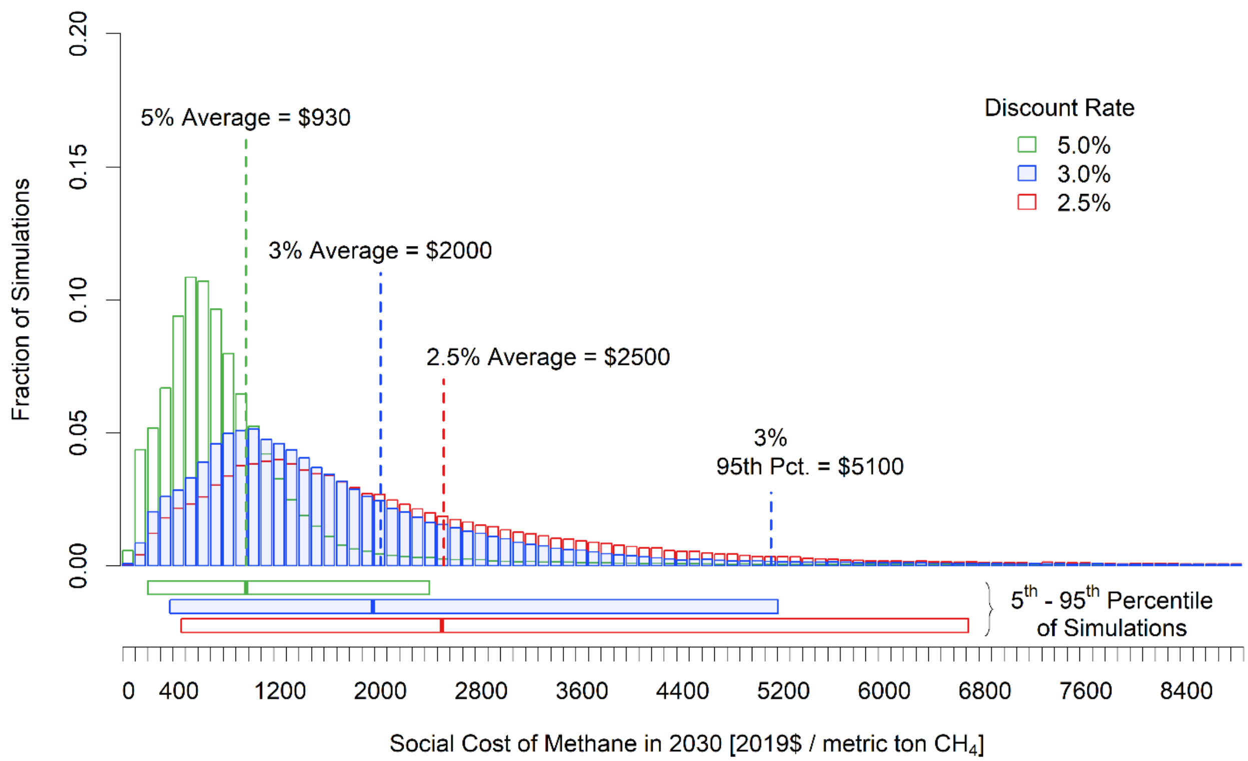

Figure 3-1 Frequency Distribution of SC-CH_4 Estimates for 2030

The interim SC-CH_4 estimates presented in Table 3-3 have a number of limitations. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower (IWG, 2021). Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their "damage functions" — i.e., the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages — lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. Likewise, the socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections.

The modeling limitations do not all work in the same direction in terms of their influence on the SC-GHG estimates. However, the IWG has recommended that, taken together, the limitations suggest that the interim SC-GHG estimates used in this proposed rule likely underestimate the damages from GHG emissions. In particular, the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (IPCC, 2007), which was the most current IPCC assessment available at the time when the IWG decision over the ECS input was made, concluded that SC-CO2 estimates "very likely…underestimate the damage costs" due to omitted impacts. Since then, the peer-reviewed literature has continued to support this conclusion, as noted in the IPCC's Fifth Assessment report (IPCC, 2014) and other recent scientific assessments (e.g., IPCC (2018, 2019a, 2019b)); U.S. Global Change Research Program (USGCRP, 2016, 2018); and the National Academies of Sciences, Engineering, and Medicine (National Academies, 2017, 2019). These assessments confirm and strengthen the science, updating projections of future climate change and documenting and attributing ongoing changes. For example, sea level rise projections from the IPCC's Fourth Assessment report ranged from 18 to 59 centimeters by the 2090s relative to 1980-1999, while excluding any dynamic changes in ice sheets due to the limited understanding of those processes at the time (IPCC, 2007). A decade later, the Fourth National Climate Assessment projected a substantially larger sea level rise of 30 to 130 centimeters by the end of the century relative to 2000, while not ruling out even more extreme outcomes (USGCRP, 2018). EPA has reviewed and considered the limitations of the models used to estimate the interim SC-GHG estimates, and concurs with the February 2021 SC-GHG TSD's assessment that, taken together, the limitations suggest that the interim SC-GHG estimates likely underestimate the damages from GHG emissions. The February 2021 SC-GHG TSD briefly previews some of the recent advances in the scientific and economic literature that the IWG is actively following and that could provide guidance on, or methodologies for, addressing some of the limitations with the interim SC-GHG estimates.

There are several limitations specific to the estimation of SC-CH_4. For example, the SC-CH_4 estimates do not reflect updates from the IPCC regarding atmospheric and radiative efficacy. Another limitation is that the SC-CH_4 estimates do not account for the direct health and welfare impacts associated with tropospheric ozone produced by methane (see the 2016 NSPS RIA for further discussion; see also Sarofim et al. (2017), reporting that studies have found the global ozone-related mortality benefits of CH_4 emissions reductions, which are not included in the social cost of methane valuations, to be \$800 to \$1,800 per metric ton of methane emissions). 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. See EPA-HQ-OAR-2015-0827-5886 for more detailed discussion about the limitations specific to the estimation of SC-CH_4. These individual limitations and uncertainties do not all work in the same direction in terms of their influence on the SC-CH_4 estimates.

Table 3-4 presents the undiscounted annual monetized climate benefits under the proposed NSPS OOOOb and EG OOOOc. Projected methane emissions reductions each year are multiplied by the SC-CH_4 estimate for that year.[73] Table 3-5 shows the annual climate benefits

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[73] According to OMB's Circular A-4 (OMB, 2003), an "analysis should focus on benefits and costs that accrue to citizens and residents of the United States", and international effects should be reported, but separately. Circular A-4 also reminds analysts that "[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues." To correctly assess the total climate damages to U.S. citizens and residents, an analysis should account for all the ways climate impacts affect the welfare of U.S. citizens and residents, including how U.S. GHG mitigation activities affect mitigation activities by other countries, and spillover effects from climate action elsewhere. The SC-GHG estimates used in regulatory analysis under revoked EO 13783 were a limited approximation of some of the U.S. specific climate damages from GHG emissions. These estimates range from \$204 per metric ton CH_4 (2019 dollars) using a 3 percent discount rate for emissions occurring in 2023 to \$279 per metric ton CH_4 using a 3 percent discount rate for emissions occurring in 2035. Applying these estimates (based on a 3 percent discount rate) to the CH_4 emissions reduction expected under the proposed rule would yield benefits from climate impacts of \$27 million in 2023, increasing to \$890 million in 2035. However, as discussed at length in the IWG's February 2021 SC-GHG TSD, these estimates are an underestimate of the benefits of CH4 mitigation accruing to U.S. citizens and residents, as well as being subject to a considerable degree of uncertainty due to the manner in which they are derived. In particular, as discussed in this analysis, EPA concurs with the assessment in the February 2021 SC-GHG TSD that the estimates developed under revoked E.O. 13783 did not capture significant regional interactions, spillovers, and other effects and so are incomplete underestimates. As the U.S. Government Accountability Office (GAO) concluded in a June 2020 report examining the SC-GHG estimates developed under E.O. 13783, the models "were not premised or calibrated to provide estimates of the social cost of carbon based on domestic damages" (U.S. GAO 2020, p. 29). Further, the report noted that the National Academies found that country-specific social costs of carbon estimates were "limited by existing methodologies, which focus primarily on global estimates and do not model all relevant interactions among regions" (U.S. GAO 2020, p. 26). It is also important to note that the SC-GHG estimates developed under E.O. 13783 were never peer reviewed, and when their use in a specific regulatory action was challenged, the U.S. District Court for the Northern District of California determined that use of those values had been "soundly rejected by economists as improper and unsupported by science," and that the values themselves omitted key damages to U.S. citizens and residents including to supply chains, U.S. assets and companies, and geopolitical security. The Court found that by omitting such impacts, those estimates "fail[ed] to consider…important aspect[s] of the problem" and departed from the "best science available" as reflected in the global estimates. *California v. Bernhardt*, 472 F. Supp. 3d 573, 613-14 (N.D.Cal. 2020). EPA continues to center attention in this analysis on the global measures of the SC-GHG as the appropriate estimates given the flaws in the U.S. specific estimates, and as necessary for all countries to use to achieve an efficient allocation of resources for emissions reduction on a global basis, and so benefit the U.S. and its citizens.

discounted back to 2021 and the PV and the EAV for the 2023–2035 period under each discount rate.

Table 3-4 Undiscounted Monetized Climate Benefits under the NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions, 2019$)

	Undiscounted[a]			
Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2023	$97	$210	$280	$560
2024	$150	$330	$430	$880
2025	$220	$470	$610	$1,200
2026	$2,600	$5,500	$7,100	$15,000
2027	$2,700	$5,700	$7,300	$15,000
2028	$2,800	$5,800	$7,500	$15,000
2029	$2,800	$6,000	$7,700	$16,000
2030	$2,900	$6,100	$7,900	$16,000
2031	$3,100	$6,300	$8,100	$17,000
2032	$3,200	$6,500	$8,300	$17,000
2033	$3,300	$6,700	$8,500	$18,000
2034	$3,400	$6,900	$8,700	$18,000
2035	$3,500	$7,100	$8,900	$19,000

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

Table 3-5 Discounted Monetized Climate Benefits under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions, 2019$)

	Discounted back to 2021[a]			
Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2023	$88	$200	$260	$520
2024	$130	$300	$400	$810
2025	$180	$420	$550	$1,100
2026	$2,000	$4,700	$6,300	$13,000
2027	$2,000	$4,700	$6,300	$13,000
2028	$2,000	$4,700	$6,300	$13,000
2029	$1,900	$4,700	$6,300	$13,000
2030	$1,900	$4,700	$6,300	$12,000
2031	$1,900	$4,700	$6,300	$12,000
2032	$1,900	$4,700	$6,300	$12,000
2033	$1,800	$4,700	$6,300	$12,000
2034	$1,800	$4,700	$6,300	$12,000
2035	$1,800	$4,700	$6,300	$12,000
PV	**$19,000**	**$48,000**	**$64,000**	**$130,000**
EAV	**$2,100**	**$4,500**	**$5,900**	**$12,000**

Note: Totals may not appear to add correctly due to rounding.
[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

As discussed in the November 2021 proposal RIA, the IWG is currently working on a comprehensive update of the SC-GHG estimates under E.O. 13990 taking into consideration recommendations from the National Academies of Sciences, Engineering and Medicine, recent scientific literature, and public comments received on the February 2021 SC-GHG TSD. EPA is a member of the IWG and is participating in the IWG's review and updating process under E.O. 13990. While that process continues, the EPA is taking the opportunity in this RIA to present a sensitivity analysis of the monetized climate benefits of this proposed action using an updated set of SC-CH_4 estimates, newly developed by EPA, based on newly available research and methodological updates addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). This sensitivity analysis is provided in Appendix B below. More information about the development of these new estimates is available at: https://www.epa.gov/environmental-economics/scghg.

3.3 Ozone-Related Impacts Due to VOC Emissions

This proposed rulemaking is projected to reduce 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 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 . Emissions reductions may decrease ozone formation, human exposure to ozone, and the incidence of ozone-related health effects.

Calculating ozone impacts from changes in VOC emissions requires information about the spatial patterns in those emissions changes. In addition, the ozone health effects from the proposed rule will depend on the relative proximity of expected VOC and ozone changes to population. In this analysis, we have not characterized VOC emissions changes at a finer spatial resolution than the national total due to data and resource constraints. In light of these limitations, we present an illustrative screening analysis of ozone-related health benefits in Appendix C based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017 and do not include the results of this screening analysis in the estimate of benefits (and net benefits) projected from this proposal.[74] To more definitively analyze the impacts of VOC reductions from this proposed rule on ozone health benefits, we would need credible projections of spatial patterns of expected VOC emissions reductions. Similarly, due to the high degree of variability in the responsiveness of ozone formation to VOC emissions reductions, we are unable to determine how this rule might affect air quality in downwind ozone nonattainment areas without modeling air quality changes. 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.

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[74] Note that this illustrative analysis does not reflect the health and welfare benefits from reductions in tropospheric ozone production resulting from CH_4 emissions.

3.3.1 *Ozone Health 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.

3.3.2 *Ozone Vegetation Effects*

Exposure to ozone has been found to be associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2020a). Sensitivity to ozone is highly variable across species, with over 66 vegetation species identified as "ozone-sensitive," many of which occur in state and national parks and forests. These effects include those that cause damage to, or impairment of, the intended use of the plant or ecosystem. Such effects are considered adverse to public welfare and can include reduced growth and/or biomass production in sensitive trees, reduced yield and quality of crops, visible foliar injury, changed to species composition, and changes in ecosystems and associated ecosystem services.

3.3.3 *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, 2009b). 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.

3.4 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 included in estimates of the social cost of methane and are not otherwise quantified or monetized in this anlaysis.

3.5 $PM_{2.5}$-Related Impacts Due to VOC Emissions

This proposed 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 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, Kroll, Pandis, & Robinson, 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 proposal 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.

3.5.1 $PM_{2.5}$ 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, 2021f).

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.

3.5.2 PM 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 (U.S. EPA, 2006, 2011a, 2011d, 2012) show that visibility benefits are a significant welfare benefit category. 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, 2009a). 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, 2012).

3.6 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 3-6. 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 3-6 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 3.6.1), formaldehyde (Section 3.6.2), toluene (Section 3.6.3), carbonyl sulfide (Section 3.6.4), ethylbenzene (Section 3.6.5), mixed xylenes (Section 3.6.6), and n-hexane (Section 3.6.7), and other air toxics (Section 3.6.8). This proposal is projected to reduce 280,000 tons of HAP emissions over the 2023 through 2035 period.[75] With the data available, it was not possible to estimate the change in emissions of each individual HAP.

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

[75] 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.

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 proposed 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 4.2.4.

3.6.1 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, Stillman, Colagiovanni, & Henry, 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).

3.6.2 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).

3.6.3 Toluene[76]

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.

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,

[76] All health effects language for this section came from: U.S. EPA (2005b).

decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

3.6.4 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.[77] 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).

3.6.5 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 cavities in male and female rats exposed to ethylbenzene via the oral route (Maltoni et al., 1997; Maltoni, Conti, Cotti, & Belpoggi, 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 International Agency for Research on Cancer (IARC, 2000) and the National Toxicology

[77] 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.

Program (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. NTP (1999) 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 in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

3.6.6 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.

3.6.7 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.

3.6.8 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.[78]

3.7 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 3-7 shows the estimated secondary emissions associated with combustion of emissions as a result of these requirements. Relative to the direct emission reductions anticipated from this rule, the magnitude of these secondary air pollutant increases is small.

Table 3-7 Increases in Secondary Air Pollutant Emissions, Vapor Combustion at Storage Vessels (short tons per year)

Year	THC	CO	NO_X	PM	CO_2
2023	21	55	10	0	43,000
2024	29	78	14	1	61,000
2025	37	98	18	1	78,000
2026	44	120	21	1	91,000
2027	49	130	24	1	100,000
2028	53	140	26	1	110,000
2029	57	150	28	1	120,000
2030	60	160	29	1	120,000
2031	62	160	30	1	130,000
2032	64	170	31	1	130,000
2033	66	170	32	1	140,000
2034	67	180	33	1	140,000
2035	69	180	33	1	140,000
Total	680	1,800	330	12	1,400,000

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

The CO_2 impacts in Table 3-7 are the emissions that are expected to occur from vapor combustion at affected storage vessels. However, because of the atmospheric chemistry

[78] The U.S. EPA Integrated Risk Information System (IRIS) database is available at https://www.epa.gov/iris. Accessed April 26, 2020.

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.[79] 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 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 estimated impact of CO_2 produced in the future via oxidized methane from these fossil-based emissions may be less than 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.[80] The analysis demonstrated that the potential disbenefits of flaring (i.e., an earlier

[79] 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.
[80] See Section 4.7 of U.S. EPA (2016).

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 proposed 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 dynamic and consistent with the modeling that underlies the SC-CH_4 estimates and assumes an average methane oxidation period of 12 years, consistent with the perturbation lifetime-folding time used in IPCC AR4. The estimated disbenefits associated with destroying one metric ton of methane through combustion of emissions at oil and 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 \$19 per metric ton CH_4 (based on average SC-CO_2 at 3 percent) or about one percent of the SC-CH_4 estimate per metric ton for 2023. The analogous estimate for 2035 is \$30 per metric ton CH_4 or about one percent of the SC-CH_4 estimates per metric ton for 2035.[81]

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

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[81] 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 a 12 year e-folding time using the same discount rate as used to estimate the SC-CO_2. 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:

$$(44/16)\left[\text{SC-CO2}_\tau - \sum_{t=\tau}^{T} e^{-1/12(t-\tau)}\left(1-e^{-1/12}\right)\left(\frac{1}{1+r}\right)^{t-\tau}\text{SC-CO2}_t\right]$$ where τ is the year the CH_4 is destroyed, 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 2050, the last year for which the IWG provides estimates. 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.

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.

3.8 Total Benefits

Table 3-8 presents the PV and EAV of the projected climate benefits across the three regulatory options for the proposed NSPS OOOOb and EG OOOOc examined in this RIA. These values reflect an analytical time horizon of 2023 to 2035, 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 proposal. Table 3-9 and Table 3-10 present the same information for the proposed NSPS OOOOb and EG OOOOc separately.

Table 3-8 Comparison of PV and EAV of the Projected Benefits for the Proposed NSPS OOOOb and EG OOOOc across Regulatory Options, 2023–2035 (millions of 2019$)

Year	5% Average	3% Average	2.50% Average	3% 95th Percentile
Climate Benefits (PV)[a]				
Less Stringent	$6,800	$17,000	$23,000	$45,000
Proposal	$19,000	$48,000	$64,000	$130,000
More Stringent	$19,000	$48,000	$65,000	$130,000
Climate Benefits (EAV)[a]				
Less Stringent	$720	$1,600	$2,100	$4,200
Proposal	$2,100	$4,500	$5,900	$12,000
More Stringent	$2,100	$4,500	$5,900	$12,000
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent	12,000,000			
Proposal	36,000,000			
More Stringent	36,000,000			
$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons)[b,c]:				
Less Stringent	3,400,000			
Proposal	9,700,000			
More Stringent	9,800,000			
HAP benefits from reducing HAP emissions by (in short tons):				
Less Stringent	150,000			
Proposal	390,000			
More Stringent	390,000			
Visibility benefits				
Reduced vegetation effects				

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate. For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017).
[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix C of the RIA.
[c] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

Table 3-9 Comparison of PV and EAV of the Projected Benefits for the Proposed NSPS OOOOb across Regulatory Options, 2023-2035 (millions of 2019$)

Year	5% Average	3% Average	2.50% Average	3% 95th Percentile
Climate Benefits (PV)[a]				
Less Stringent	$800	$2,000	$2,700	$5,300
Proposal	$4,400	$11,000	$15,000	$29,000
More Stringent	$4,400	$11,000	$15,000	$29,000
Climate Benefits (EAV)[a]				
Less Stringent	$86	$190	$240	$500
Proposal	$470	$1,000	$1,300	$2,700
More Stringent	$470	$1,000	$1,300	$2,700
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent		1,900,000		
Proposal		8,100,000		
More Stringent		10,000,000		
$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons)[b,c]:				
Less Stringent		1,400,000		
Proposal		2,900,000		
More Stringent		3,600,000		
HAP benefits from reducing HAP emissions by (in short tons):				
Less Stringent		52,000		
Proposal		110,000		
More Stringent		140,000		
Visibility benefits				
Reduced vegetation effects				

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate. For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017).
[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix C of the RIA.
[c] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

Table 3-10 Comparison of PV and EAV of the Projected Benefits for the Proposed EG OOOOc Across Regulatory Options, 2023-2035 (millions of 2019$)

Year	5% Average	3% Average	2.50% Average	3% 95th Percentile
Climate Benefits (PV)[a]				
Less Stringent	$6,000	$15,000	$20,000	$39,000
Proposal	$15,000	$37,000	$50,000	$98,000
More Stringent	$15,000	$37,000	$50,000	$99,000
Climate Benefits (EAV)[a]				
Less Stringent	$640	$1,400	$1,800	$3,700
Proposal	$1,600	$3,500	$4,500	$9,300
More Stringent	$1,600	$3,500	$4,600	$9,300
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent		11,000,000		
Proposal		28,000,000		
More Stringent		28,000,000		
$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons)[b,c]:				
Less Stringent		2,300,000		
Proposal		6,800,000		
More Stringent		6,900,000		
HAP benefits from reducing HAP emissions by (in short tons):				
Less Stringent		110,000		
Proposal		280,000		
More Stringent		280,000		
Visibility benefits				
Reduced vegetation effects				

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate. For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017).
[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix C of the RIA.
[c] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

4 ECONOMIC IMPACT AND DISTRIBUTIONAL ANALYSIS

The proposed NSPS OOOOb and EG OOOOc constitute an economically significant action. As discussed in previous section, the emissions reductions projected under the rule are likely to produce substantial climate benefits, peaking at $3.5 to $19 billion in 2035, as well as non-monetized benefits from large reductions in VOC and HAP emissions. At the same time, the proposed 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, reaching a maximum of $2.8 billion in 2026.

While the national level impacts demonstrate the proposal 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 proposed rule, which may be important consequences of the action. This section includes four sets of economic impact and distributional analyses for this proposal directed toward complementing the benefit-cost analysis and includes an analysis of potential national-level impacts on oil and natural gas markets, a series of environmental justice analyses, an Initial Regulatory Flexibility Analysis that includes an analysis of projected compliance costs of proposed NSPS OOOOb on small entities, and employment impacts.

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 proposed 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 (Siliverstovs, L'Hégaret, Neumann, & von Hirschhausen, 2005). 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 proposed 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 proposed 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 2023 and 2025 as these years represent the first and last year the requirements in the proposed NSPS OOOOb will be in effect for the purposes of the RIA before the requirement of the proposed EG OOOOc are assumed to go into effect. We then analyze market impacts in 2026, 2030, and 2035 to examine the effects of the proposed EG OOOOc in addition to the cumulative impacts of the proposed NSPS OOOOb. The year 2026 is the year of analysis with the highest regulatory costs and, as such, will represent the year with the largest market impacts based upon the partial equilibrium market models used here. We analyze 2030 and 2035 in order to project impacts in later years of the time horizon, as the projected regulatory costs decline.

4.1.3.2 Elasticity Choices

The elasticity estimates used in the analysis are based on estimates from the published economics literature (Table 4-1). 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	Newell, 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 proposed 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 2020 International Energy Outlook. Table 4-2 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 2023	2025	2026	2030	2035
Baseline Production[a]							
	U.S. Crude Oil Production	million bbl/day	10.3	11.0	11.1	11.0	10.8
	World Oil Production	million bbl/day	97.1	97.7	98.0	99.5	101.8
	U.S. Onshore Production	tcf/year	35.3	35.7	35.7	36.5	37.2
Baseline Prices[a]							
	Crude Oil	2019$/bbl	55.8	61.4	62.6	67.7	72.0
	Natural Gas	2019$/MMbtu	3.31	2.85	2.83	3.28	3.45
	Natural Gas	2019$/Mcf	3.44	2.95	2.93	3.40	3.58

[a] Baseline U.S. crude oil and natural gas production and prices drawn from AEO2021. 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 proposed 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 Proposed NSPS OOOOb and EG OOOOc Option Applied in the Market Analysis (millions 2019$)

	Year				
Resource	**2023**	**2025**	**2026**	**2030**	**2035**
Crude Oil	70.7	157.2	1,094.6	1,067.2	1,112.0
Natural Gas	25.8	59.6	1,165.6	1,000.9	931.3

4.1.4 Results

The results of incorporating the projected regulatory costs into the crude oil market model are presented in Table 4-4. At its peak, the reduction is about 20.98 million barrels in 2026 or about 0.52 percent of crude oil production.

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

Variable	Change	Year				
		2023	2025	2026	2030	2035
U.S. Production	million bbls/year	-1.52	-3.07	-20.98	-18.92	-18.53
	%	-0.04%	-0.08%	-0.52%	-0.47%	-0.47%
U.S. Prices						
Assuming Perfectly Inelastic Rest of World Supply	$/bbl	0.01	0.01	0.10	0.10	0.10
	%	0.01%	0.02%	0.16%	0.14%	0.13%
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. 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 0.10 dollars per barrel in 2026, an increase of less than one sixth of one 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 $0.07 per mcf and a maximum production reduction of about 358.0 million Mcf per year, changes of about 2.35 percent and 1.00 percent respectively.

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

Variable	Change	Year				
		2023	2025	2026	2030	2035
U.S. Onshore Production	million Mcf/year	-6.8	-18.2	-358.0	-264.6	-234.2
	%	-0.02%	-0.05%	-1.00%	-0.73%	-0.63%
U.S. Prices						
	2019$/Mcf	0.00	0.00	0.07	0.06	0.05
	%	0.04%	0.12%	2.35%	1.70%	1.47%

We use the results in Table 4-4 and Table 4-5 to evaluate whether the proposed 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".”[82] The maximum projected annual decreases in both oil production and natural gas production exceed benchmarks for adverse effects, so this analysis indicates the proposed 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 parameters include the cost to firms of compliance, the amount of natural gas that would be recovered and sold as a result 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 proposed 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 proposed 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

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

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 Environmental Justice Analyses

Executive Order 12898 directs the EPA to "achiev[e] environmental justice (EJ) by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects" (59 FR 7629, February 16, 1994), termed disproportionate impacts in this chapter. Additionally, Executive Order 13985 was signed to advance racial equity and support underserved communities through Federal government actions (86 FR 7009, January 20, 2021). The EPA defines EJ as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to mean that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies".[83] Meaningful involvement means that: (1) potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health; (2) the public's contribution can influence the regulatory Agency's decision; (3) the concerns of all participants involved will be considered in the decision-making process; and (4) the rule-writers and decision-makers seek out and facilitate the involvement of those potentially affected.

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

The term "disproportionate impacts" refers to differences in impacts or risks that are extensive enough that they may merit Agency action.[84] In general, the determination of whether a disproportionate impact exists is ultimately a policy judgment which, while informed by analysis, is the responsibility of the decision-maker. The terms "difference" or "differential" indicate an analytically discernible distinction in impacts or risks across population groups. It is the role of the analyst to assess and present differences in anticipated impacts across population groups of concern for both the baseline and proposed regulatory options, using the best available information (both quantitative and qualitative) to inform the decision-maker and the public.

A regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples through the action under development.

The Presidential Memorandum on Modernizing Regulatory Review (86 FR 7223; January 20, 2021) calls for procedures to "take into account the distributional consequences of regulations, including as part of a quantitative or qualitative analysis of the costs and benefits of regulations, to ensure that regulatory initiatives appropriately benefit, and do not inappropriately burden disadvantaged, vulnerable, or marginalized communities." Under Executive Order 13563, federal agencies may consider equity, human dignity, fairness, and distributional considerations, where appropriate and permitted by law. For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,"[85] 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

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

factors may make population groups of concern more vulnerable to adverse effects (e.g., underlying risk factors that may contribute to higher exposures and/or impacts). It is also important to evaluate the data and methods available for conducting an EJ analysis. EJ analyses can be grouped into two types, both of which are informative, but not always feasible for a given rulemaking:

1. Baseline: Describes the current (pre-control) distribution of exposures and risk, identifying potential disparities.
2. Policy: Describes the distribution of exposures and risk after the regulatory option(s) have been applied (post-control), identifying how potential disparities change in response to the rulemaking.

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

4.2.1 Analyzing EJ Impacts in This Supplemental Proposal

For this proposed rulemaking, the EPA conducted limited environmental justice (EJ) analyses focused on a baseline distribution of emissions from oil and natural gas sources. EJ analyses described in this section evaluate only baseline scenarios; this enables us to characterize risks due to oil and natural gas emissions prior to implementation of the proposed rule. However, we lack key information that would be needed to characterize post-control risks under the proposed NSPS OOOOb and EG OOOOc or the regulatory alternatives analyzed in this RIA. Therefore, the extent to which this proposed rule will affect potential EJ concerns is not evaluated explicitly due to data limitations that prevent us from analyzing spatially differentiated outcomes.

As policy-specific air quality scenarios corresponding to future years analyzed in this proposal (e.g., 2023 to 2035) were not evaluated, it is unknown how the proposed rule will impact potential EJ concerns that may relate to the distribution of oil and natural gas emissions, as well as those related to employment. Importantly, we note that this proposal may not impact all locations with oil and natural gas emissions equally, in part due to differences in existing state regulations in locations like Colorado and California, which have more stringent requirements.

Additionally, these discussions and analyses are subject to various types of uncertainty related to input parameters and assumptions.

We present several potential vulnerabilities to climate-related stress qualitatively in Section 4.2.2. Quantitative EJ assessments include an analysis of ozone from oil and natural gas VOC emissions (Section 4.2.3), risk from oil and natural gas air toxic emissions (Section 4.2.4), oil and natural gas workers and communities (Section 4.2.5), and how households may be affected by potential energy market impacts (Section 4.2.6). Overall, there is some evidence that certain populations may be disproportionately impacted by oil and natural gas emissions, although data gaps remain.

4.2.2 Climate Impacts

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, 2016, 2018), the Intergovernmental Panel on Climate Change (IPCC) (IPCC, 2018; Oppenheimer et al., 2014; Porter et al., 2014; Smith et al., 2014), and the National Academies of Science, Engineering, and Medicine add more evidence that the impacts of climate change raise potential environmental justice concerns (National Academies, 2017; NRC, 2011). 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., African-American, 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 (2018) and *The Impacts of Climate Change on Human Health in the United States* (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 Academies, 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 or African American 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 Black and 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 and Latino 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 more risky 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.

4.2.3 Ozone from Oil and Natural Gas VOC Emission Impacts[86]

To evaluate the EJ implications of ozone from oil and natural gas VOC emissions from the oil and natural gas sector, we analyzed a recent baseline (pre-control) air quality scenario comparing exposures to ozone formed from VOC emissions from the oil and natural gas sector across races/ethnicities, ages, and sexes. We focus mainly on exposure differences because these provide the clearest view into whether emissions from this sector may be unequally distributed among population subgroups of interest.

4.2.3.1 Data Inputs

Input data for this ozone exposure EJ analysis included potential population characteristics of concern, and air quality scenarios.

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[86] The illustrative screening analysis of projected ozone-related health benefits from VOC reductions under the primary proposal (presented in Appendix C of the proposal RIA) was subject to uncertainties in addition to those associated with the baseline ozone-related environmental justice analysis presented in this section. For example, the VOC emissions contributing to baseline concentrations of ozone in the environmental justice analysis are derived from the NEI, while the emissions reductions projected under the proposal for this RIA are based upon a mix of model plant information used in the rulemaking and activity factors as described in Section 2.2. Importantly, the illustrative screening analysis projects emissions reductions at a national-level while the NEI-based emissions informing the air quality modeling underpinning the environmental justice analysis are more spatially resolved. Importantly, insufficient scientific evidence and technical limitations prevent us from stratifying relationships between ozone exposures and health effects. we quantitatively assessed EJ exposure impacts of oil and natural gas ozone from VOC emissions in the baseline among certain subpopulations of interest. As noted, we stopped short of characterizing the respiratory mortality risk among these populations, or drawing comparisons among them, due to the impact on results caused by differences in the age distributions, and therefore baseline incidence rates of respiratory mortality, of White and non-White populations. In addition, risk results are strongly influenced by the age distributions of various potential EJ subpopulations. Specifically, populations with higher median ages and those with larger populations of older adults (e.g., White populations), are associated with substantially higher baseline incidence rates of respiratory mortality. Higher baseline mortality rates translate into higher estimates of risk that can obfuscate impacts from small differences in ozone exposure levels. Therefore, we removed the ozone EJ mortality analyses previously presented, to make this RIA more consistent with previous RIA's involving ozone concentration changes.

(a) Population Characteristics

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. The Health Effects Institute (HEI) provided a bibliography of peer-reviewed studies published since 2015 that evaluate populations that may be disproportionately impacted by the oil and natural gas industry.[87] However, there is considerable discordance among the study results. For example, studies differ with regards to geographic area, population of interest, and health outcome. To broadly assess potential EJ concerns, we evaluated disproportionate exposure and risk across racial and ethnic demographics, sexes, and ages as described in Table 4-6.

Table 4-6 Components of the Criteria Pollutant Environmental Justice Assessment

EJ Characteristics	Description
Race	White, Black, Asian, Native American
Ethnicity	Hispanic, Non-Hispanic
Age	0-17, 18-64, 65-99
Sex	Male, Female

(b) Air Quality Scenarios

Here we utilize modeled baseline conditions of ozone formed from oil and natural gas VOC emissions developed for the year 2017 (Figure 4-1) (U.S. EPA, 2021a). These air quality surfaces were developed using source apportionment (SA) modeling estimates of ozone concentrations attributable to certain precursors such as VOC from individual sectors, which can provide insight into the baseline (i.e., pre-rulemaking) scenario of a historical year (Appendix C, Section C.1.2).[88] Please note the scale, as concentrations of ozone formed from oil and natural gas VOC emissions represent a relatively small proportion of median annual MDA8 concentrations.[89] Higher concentrations of ozone formed from oil and natural gas VOC emissions tend to localize to areas of known oil and natural gas facility locations.

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[87] Email to EPA staff from Janet McGovern of the Health Effects Institute on May 12th, 2021. Located at Docket ID No. EPA-HQ-OAR-2021-0317.
[88] Additional information on the SA modeling is available from U.S. EPA (2021a).
[89] Median annual MDA8 ozone concentration in 2015-2017 were 40 parts per billion (ppb); see Table 1-1 in U.S. EPA (2020b).

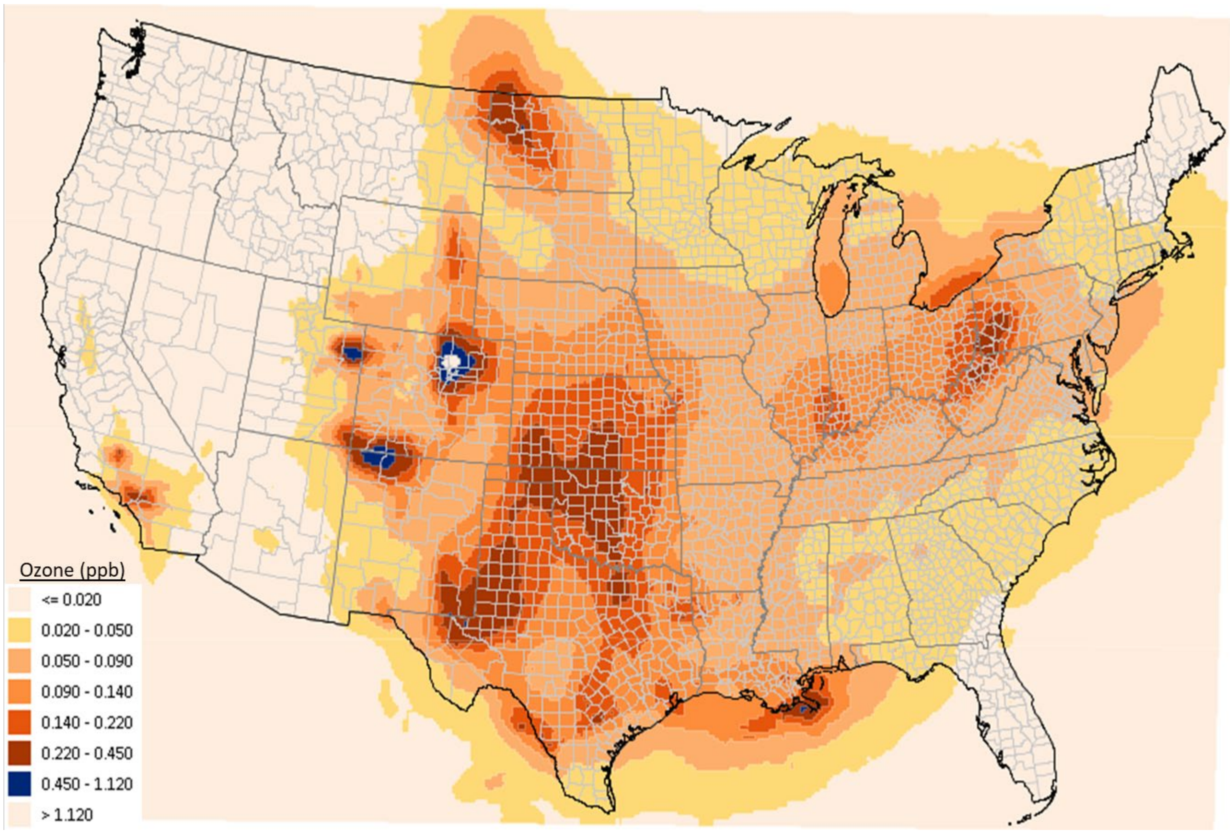

Figure 4-1 Map of Baseline Ozone Concentrations from Oil and Natural Gas VOC Emissions in 2017

4.2.3.2 Results

Results of this ozone EJ analysis include the average (Section 4.2.3.2(a)) and distribution (Section 4.2.3.2(b)) of ozone exposures.

(a) Average Ozone Exposures

Average mean daily 8-hour maximum (MDA8) ozone concentrations from oil and natural gas VOC emissions between April and September of 2017 are shown in Figure 4-2. Exposures for the overall reference group, adults of all races/ethnicities and sexes aged 30–99, is shown in the top row, with population specific comparisons available below. For example, this baseline analysis shows that Native American populations on average may be exposed to a higher concentration of ozone from oil and natural gas VOC emissions than White populations, who in turn may on average be exposed to a higher concentration than the overall reference group. Similarly, the analysis suggests that Hispanic populations on average are exposed to a higher concentration of ozone from oil and natural gas VOC emissions than both non-Hispanic individuals and the overall reference group. The right column also provides information regarding the number of people within each demographic group. For example, there were less the 2 million Native Americans and nearly 30 million Hispanics in the contiguous U.S. in 2017.

African American or Black populations and Asian populations may on average be exposed to lower concentrations than White populations and the overall reference group. Regarding sex, females and males are estimated to be exposed to similar concentrations as compared to the reference group. Finally, when comparing average exposure across age ranges, ozone concentrations from oil and natural gas VOC emissions appears to decrease as age increases.

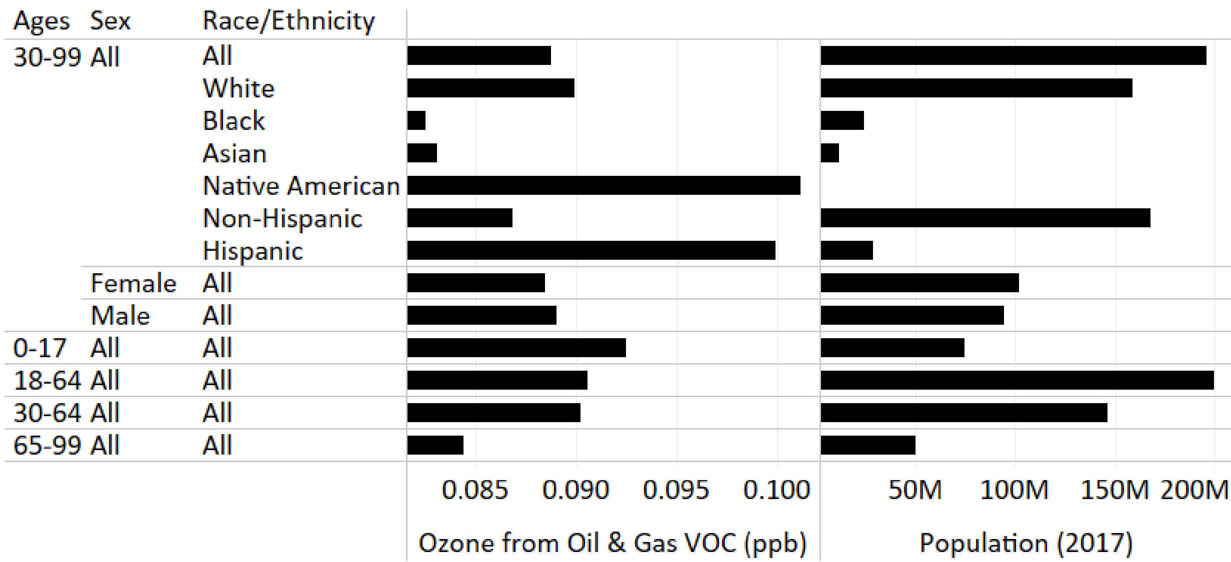

Figure 4-2 Average Ozone Concentrations from Oil and Natural Gas VOC Emissions by Population and Corresponding 2017 Population Counts

(b) Distribution of Ozone Exposures

While average exposure concentrations within demographic populations can convey some insight, distributional information, while more complex, can provide a more comprehensive understanding of the analytical results. As such, using the same baseline scenario described above, we provide the running sum percentage of each population plotted against the increasing ozone concentration from oil and natural gas VOC emissions in Figure 4-3 to permit the direct comparison of demographic populations with different absolute numbers. While the analysis indicates that exposures to ozone from oil and natural gas VOC emissions may be similar across all races/ethnicities in the lower 60 percent of each population, it suggests there are small differences in the 65–95 percent of populations exposed to higher ozone concentrations from oil and natural gas VOC emissions in some populations. Notably, a subset of Hispanics and Native American populations, shown in the dark and light orange lines, respectively, may experience slightly higher exposures to ozone from oil and natural gas VOC emissions than White and non-Hispanic populations.

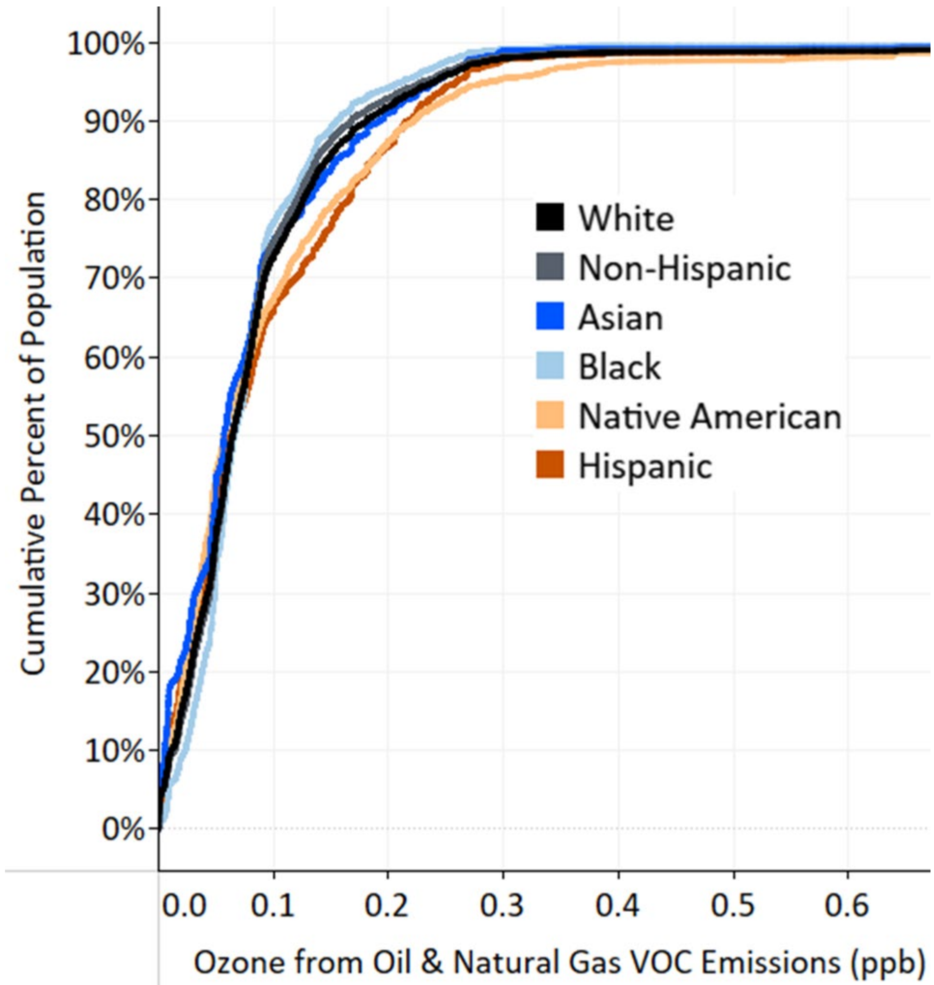

Figure 4-3 Distributions of Ozone from Oil and Natural Gas VOC Emissions Concentrations by Race/Ethnicity

Figure 4-4 shows the distribution of ozone from oil and natural gas VOC emissions across three age ranges, 0–17 shown in blue, 18–64 shown in black, and 65–99 shown in orange. Differences are very small between the three age groups, but the baseline analysis suggests exposure decreases as the age range increases.

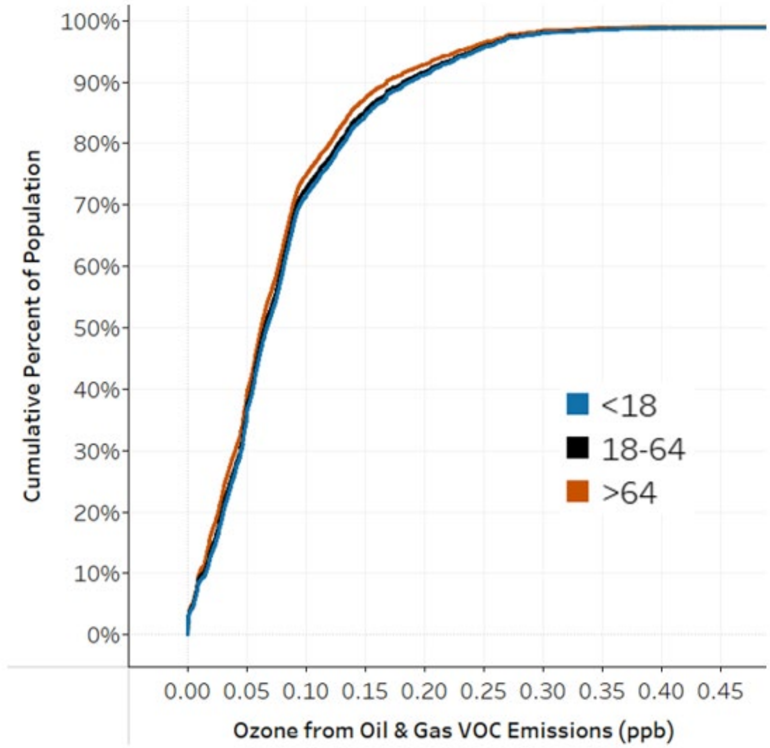

Figure 4-4 Distributions of Ozone from Oil and Natural Gas VOC Emissions Concentrations by Age Range

Figure 4-5 shows the distribution of ozone from oil and natural gas VOC emissions across males (orange) and females (blue) from our analysis. The distribution of exposures is virtually identical between the two sexes.

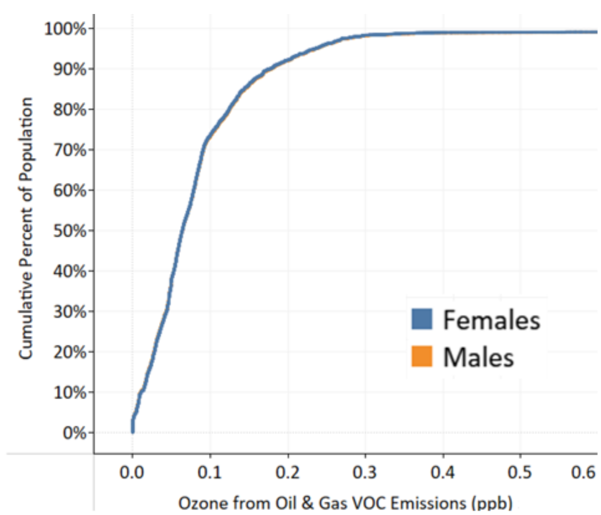

Figure 4-5 Distributions of Ozone from Oil and Natural Gas VOC Emissions Concentrations by Sex

(c) Ozone EJ Summary

This recent baseline ozone EJ analysis suggests that there may be some small differences in exposures to ozone formed from VOC emissions from the oil and natural gas sector across races/ethnicities and certain age groups. It also suggests that a substantial portion of ozone from oil and natural gas VOC emissions are localized to rural areas where fewer people reside. However, we lack the data to evaluate this on a more site-specific basis. Additionally, given the size of the sector and the number of oil and natural gas locations, it is quite possible that localized disparities may exist that our analysis did not identify.

4.2.4 Air Toxics Impacts

To evaluate the potential EJ impacts associated with baseline HAP emissions from the oil and natural gas sector, the EPA has assessed the cancer risks and estimated the demographic breakdown of people living in areas with potentially elevated risk levels. Typically, when we perform risk assessments of source categories (e.g., for Risk and Technology Review [RTR] rulemakings), we have detailed location and emissions data for each facility to be assessed and we estimate human health risks at the census block level. For the oil and natural gas sector we do not have such detailed data readily available. We used the most recent 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 3-6).

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. Another result is that the assessment is considered a screen — it is an estimate of potential risks over a broad area. More refined emissions data would need to be obtained 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 are able to 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 proposed 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 actually 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,[90] 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, 2018b). 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.[91]

The AERMOD-modeled census block concentrations are based on the 2017 NEI emissions data (see Table 3-6). 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.[92] 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.[93] For each census block, the cancer risks were summed over all pollutants to obtain a total cancer risk. The

[90] 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.
[91] Data available at https://www2.census.gov/programs-surveys/acs/summary_file/2019/data/5_year_entire_sf/.
[92] Data available at https://gaftp.epa.gov/Air/emismod/2017/AERMOD_inputs/.
[93] See https://www.epa.gov/fera/download-human-exposure-model-hem.

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.

There are approximately 3 million census blocks with nonzero total risk from oil and natural gas sources based on the AERMOD modeling of the CONUS nonpoint emissions, and these blocks are within approximately 159,000 4 km grid cells. In Alaska, there are approximately 3,500 census blocks with nonzero total risk from oil and natural gas sources based on the AERMOD modeling, and these blocks are within approximately 240 9 km grid cells. In CONUS, the 90th percentile cell risk estimate attributed to oil and natural gas sources is less than 1-in-1 million (0.8-in-1 million) and the 99.9th percentile estimate is 40-in-1 million. 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 2014 NATA results for HAP risk from all sources described above (i.e., nationwide median total cancer risk estimate from all source types of approximately 30-in-1 million), can provide context for these risk results for 2017 HAP emissions from oil and natural gas sources. The CONUS results are summarized in Table 4-7. There are about 9500 cells containing about 6.8 million people where the cell risk estimate is greater than 1-in-1 million. There are 122 cells containing about 140,000 people where the cell risk estimate is greater than or equal to 50-in-1 million, and there are 36 cells containing about 40,000 people where the cell risk estimate is greater than or equal to 100-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 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 proposed 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 above 100-in-1 million. It is likely that a majority 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 a majority of the estimated risk is likely being driven by sources not impacted by this proposed 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 million and the nonpoint cell risk of 40-in-1 million combined for an estimated 60-in-1 million risk.

Figure 4-6 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 2 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 4-7 also contains estimated numbers of people within various demographic groups who live in areas above the specified risk levels. For nearly all of 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 minority 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 African American 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.

Table 4-7 Cancer Risk and Demographic Population Estimates for 2017 NEI Nonpoint Emissions

	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**	**%**	**%**
Minority	13,268	34.1	52,154	36.5	2,010,161	29.5	39.9
African American	140	0.4	1,434	1	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 or 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	17,188	12	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

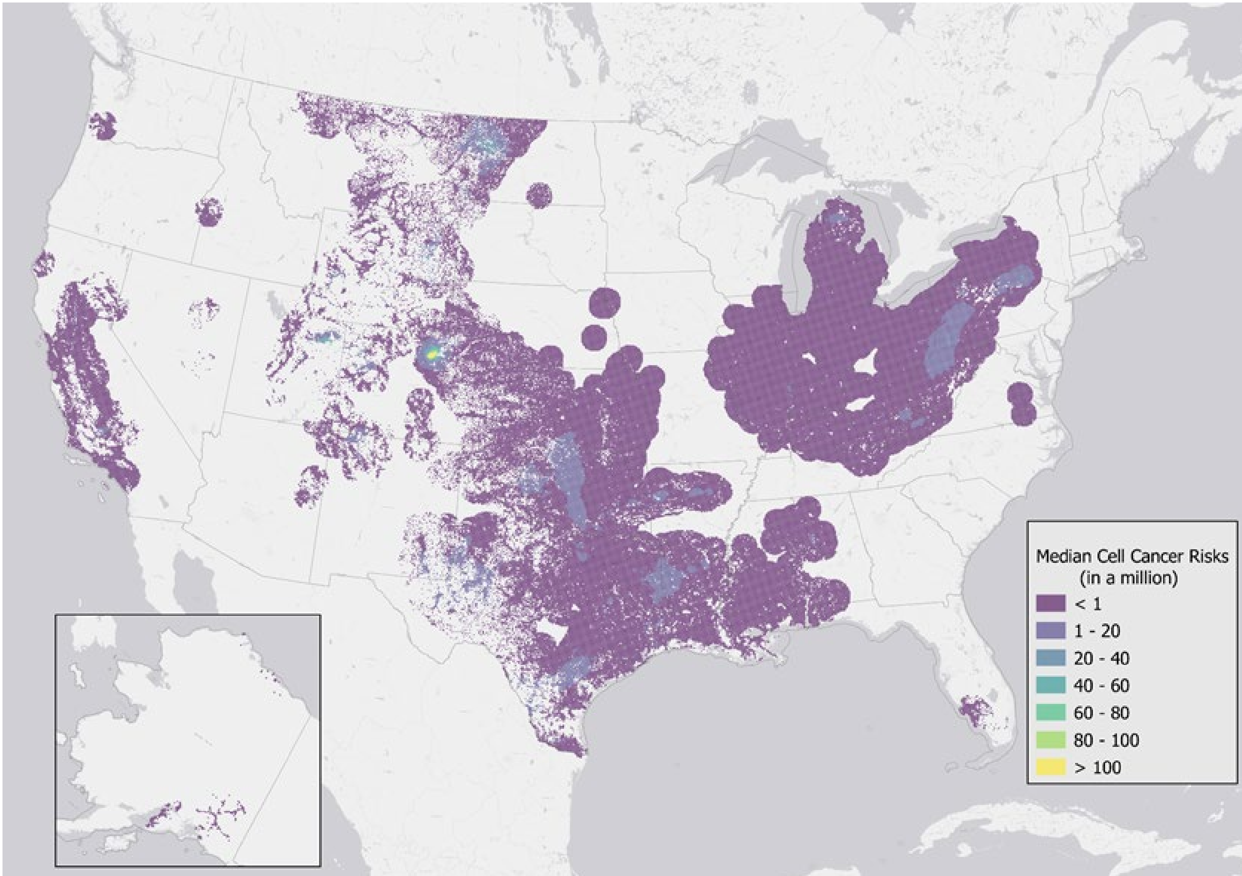

Figure 4-6 National Map of Grid Cell Median Cancer Risks for 2017 Nonpoint Oil and Natural Gas NEI Emissions

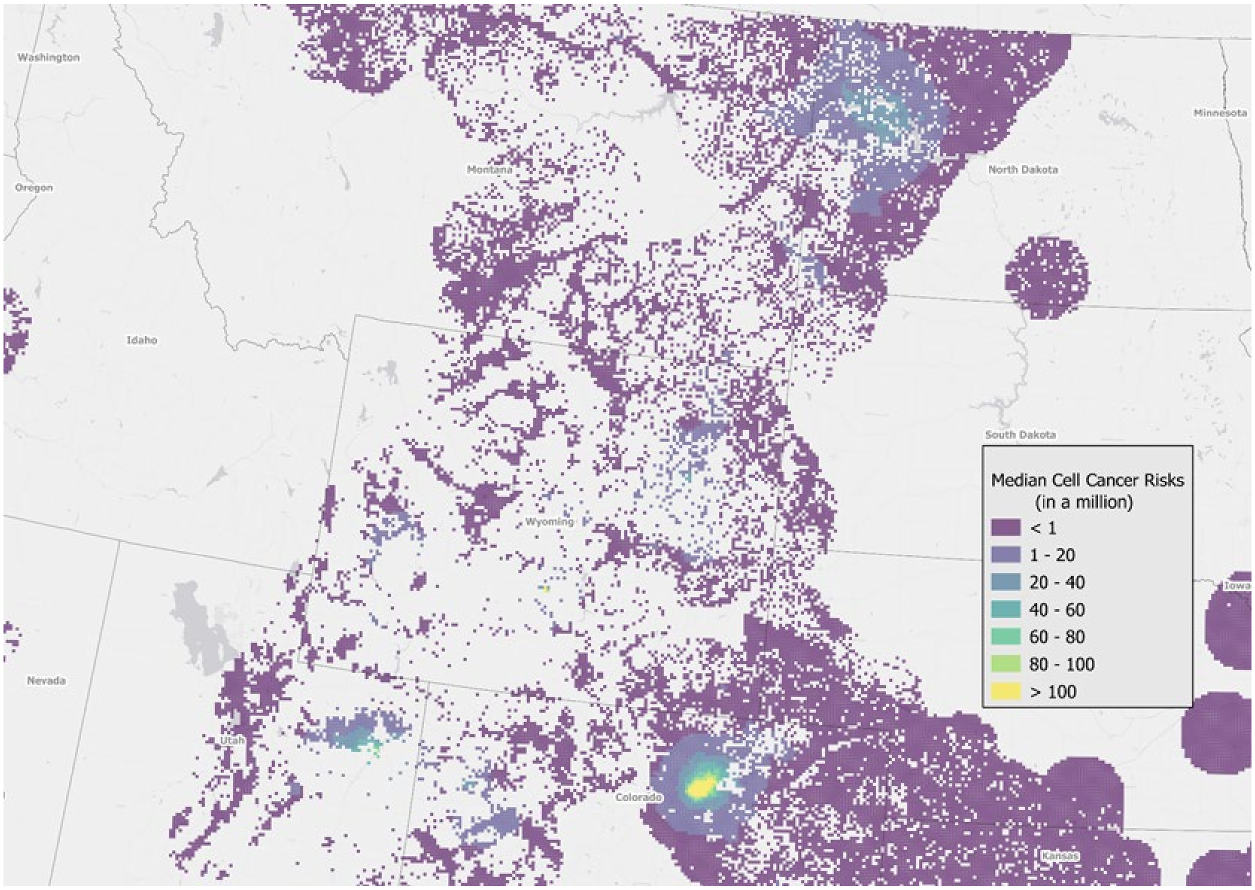

Figure 4-7 Local-Scale Map of Grid Cell Median Cancer Risks for 2017 Nonpoint Oil and Natural Gas NEI Emissions

4.2.5 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 a large number of workers in related sectors that provide materials and services. Figure 4-8 shows employment since 2001.[94] 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.

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

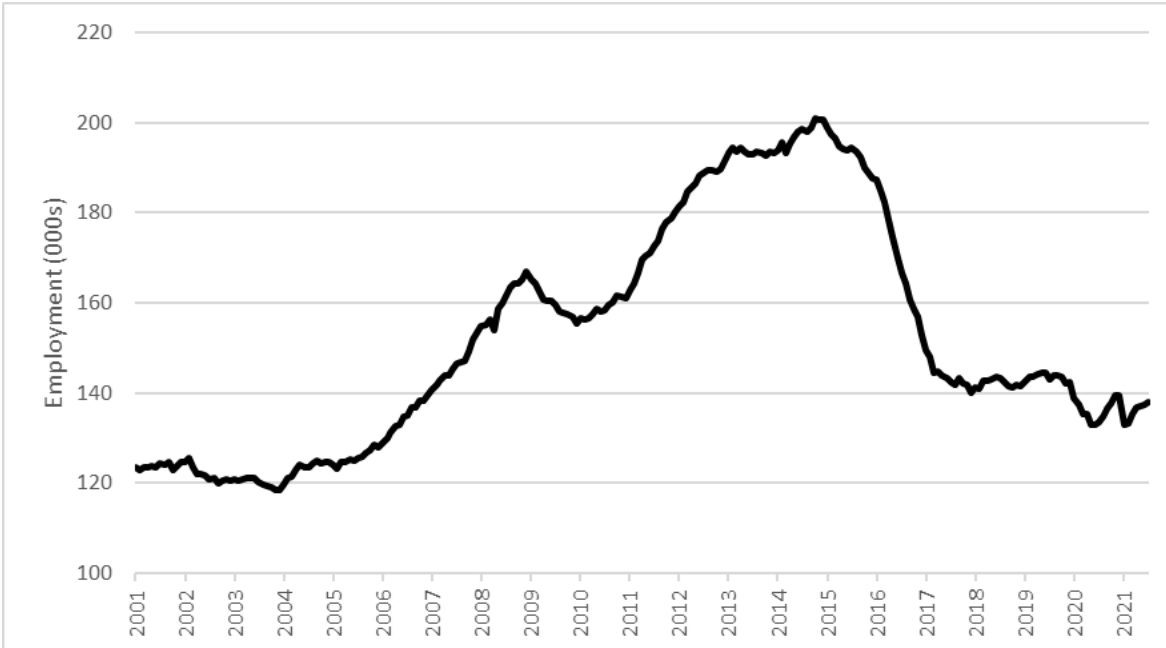

Figure 4-8 National-level Employment in Oil and Natural Gas Production

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.[95] 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 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 natural

[95] 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.

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

Table 4-8 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 and more likely to have four years of high school 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 4-8 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	$110,000	$42,000	$40,000	$43,000	$42,000
% Non-Hispanic White	81%	71%	68%	69%	71%
% English Only	87%	82%	80%	81%	82%
4 years of High School	97%	88%	86%	88%	88%

Note: Calculations based on United States Census Bureau American Community Survey public use microdata from 2014–2019.

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 4-8, oil and natural gas communities are defined as the 20 percent of PUMAs with the highest percentage of oil and natural gas workers. Figure 4-9 shows all PUMAs in the continental United States. Oil and natural gas communities as defined in Table 4-8 are highlighted.

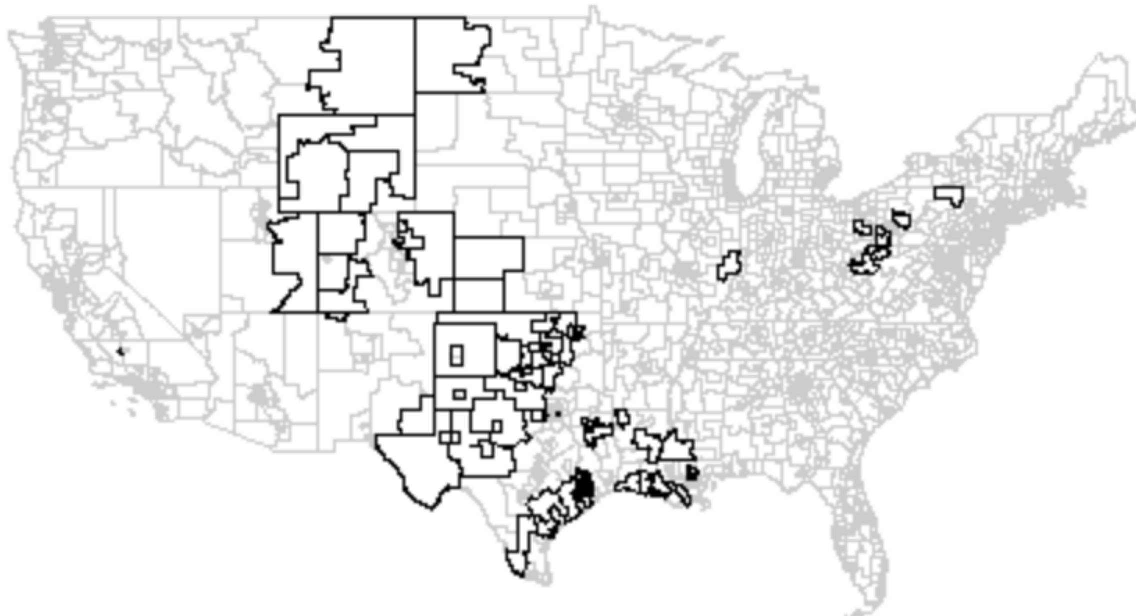

Figure 4-9 Continental U.S. Map of PUMAs and Oil and Natural Gas Intensive Communities

Table 4-9 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 80^{th} and 95^{th} percentiles of oil and natural gas industry employment, high (column (3) are the 95^{th}–97.5^{th}, and very high (column (4)) are above the 97.5^{th} percentile. People in oil and natural gas communities of Table 4-9 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 O&G 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, and fraction working in the oil and natural gas industry. 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 4-9 Demographic Characteristics of Oil and Natural Gas Communities by Oil and Natural Gas Intensity

	(1)	(2)	(3)	(4)	(5)
Category	**Non-O&G Intensive**	**Low O&G Intensity**	**High O&G Intensity**	**Very High O&G Intensity**	**Trimmed Comparison Group**
Block A:					
White	77%	81%	84%	78%	73%
Black and African-American	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	$43,000	$39,000	$39,000	$45,000	$43,000
Four years of High School	88%	87%	87%	86%	87%
Fraction Working in O&G	0.00006	0.001	0.004	0.01	0.00008

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 4-10 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 gas intensive communities.

Table 4-10 Hispanic Population by Oil and Natural Gas Intensity

Category	(1) Non-O&G Intensive	(2) Low O&G Intensity	(3) High O&G Intensity	(4) Very High O&G Intensity	(5) Trimmed Comparison Group
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 4-10 highlights oil and natural gas intensive communities with substantial EJ communities 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.

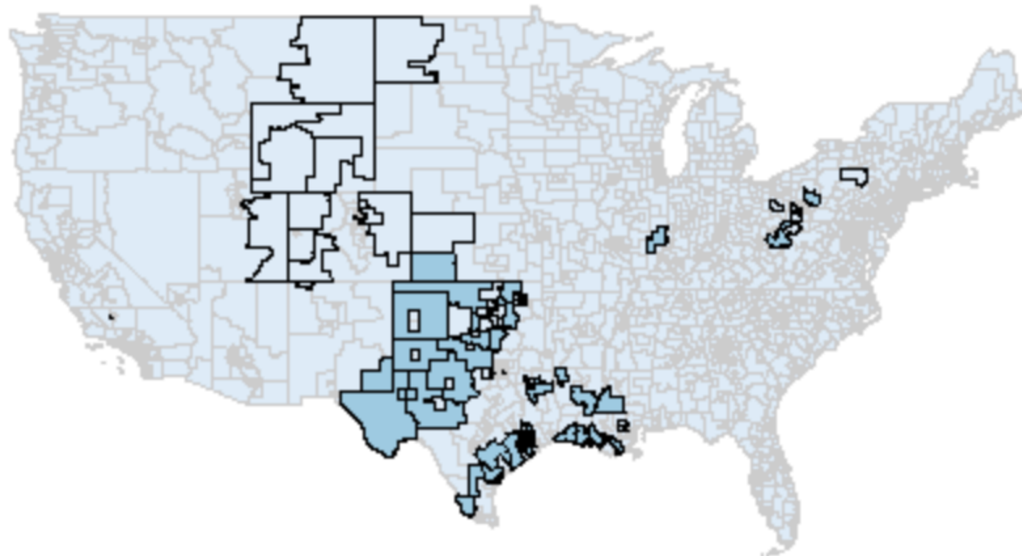

Figure 4-10 Map of Oil and Natural Gas Intensive Communities of Environmental Justice Note

4.2.6 Household Energy Expenditures

Energy provides many services to households that are necessary for a basic standard of living. The proposed 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; EIA, 2018; Kaiser & Pulsipher, 2006) and they have many consequences for human health and wellbeing (Hall, 2013; Jessel, Sawyer, & Hernández, 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, Aratani, & Jiang, 2014; Wang, Kwan, Fan, & Lin, 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, Ross, and Ayala (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 4-11 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 4-11 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 proposed 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.

4.2.7 Summary

EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis. For the proposal, we quantitatively and qualitatively evaluated baseline scenarios for several potential 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 lower educational attainment. It is also possible that the proposed rulemaking shifts the distribution of impacts, but our analysis did not assess policy-specific impacts.

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 4.2.3). Similarly, Hispanic populations may experience disproportional exposures to air pollutants from the oil and natural gas industry (Sections 4.2.3 and 4.2.4) and may be more likely to reside in communities of higher oil and natural gas intensity (Section 4.2.5). Additionally, Hispanic households' energy expenditures may comprise a disproportionate share of their total expenditures and income as compared to non-Hispanic households (Section 4.2.6). However, 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 proposed NSPS OOOOb and EG OOOOc or the regulatory alternatives analyzed in the RIA, preventing the EPA from analyzing spatially differentiated outcomes. While a definitive assessment of the impacts of this proposed rule on minority populations, low-income populations, and/or Indigenous peoples was not performed, 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.

4.3 Initial 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 proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis (IRFA), unless it certifies that the proposed 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. An IRFA describes the economic impact of the proposed rule on small entities and any significant alternatives to the proposed rule that would accomplish the objectives of the rule while minimizing significant economic impacts on small entities. Pursuant to section 603 of the RFA, the EPA prepared an IRFA that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The scope of the IRFA 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 the development of a Federal plan.

4.3.1 Reasons Why Action is Being Considered

The proposed rulemaking takes a significant step forward in mitigating climate change and improving human health by reducing GHG and VOC 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 (CO_S), as well as, benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ''BTEX''), and n-hexane.

The EPA is proposing 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 proposed 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 proposed 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. If finalized and implemented, the proposed actions would lead to significant and cost-effective reductions in climate and health-harming pollution and encourage development and deployment of innovative technologies to further reduce this pollution in the Crude Oil and Natural Gas source category.

4.3.2 Statement of Objectives and Legal Basis for Proposed Rules

The EPA proposes to revise certain NSPS and to promulgate additional NSPS for both methane and VOC emissions from new oil and 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 proposal 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 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 proposed 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 proposal, 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 proposing to revise certain of those NSPS, to add NSPS for additional sources, and to propose EG that, if finalized, 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.[96] 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 proposed 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.

4.3.3 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

[96] 81 FR 3584

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 proposal is included in Table 4-12. The EPA conducted this initial regulatory flexibility analysis at the ultimate (i.e., highest) level of ownership, evaluating ultimate parent entities.

Table 4-12 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 proposed NSPS. The list of processing plant operators is from the Department of Homeland Security (DHS) Homeland Infrastructure Foundation-Level Data.[97] 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

[97] 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

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 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 4-13. In total, 998 of the 1,451 well site operators (69%) matched to 914 ultimate parent companies; 270 of 297 processing plant operators (91%) matched to 149 ultimate parent companies; and 519 of 574 compressor station operators (90%) matched to 315 ultimate parent companies.

Table 4-13 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	352	319	91%
211130	Natural Gas Extraction	19	17	89%
213111	Drilling Oil and Gas Wells	48	45	94%
213112	Support Activities for Oil and Gas Operations	357	317	89%
486210	Pipeline Transportation of Natural Gas	31	13	42%
Many[a]	Other	419	297	71%

[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 4-12.

4.3.4 Compliance Cost Impact Estimates

To estimate the compliance cost impacts of the proposed 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 proposed NSPS.

4.3.4.1 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, $66.40/barrel. Both prices are measured in 2019$. 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 4-14.

Table 4-14 Summary Statistics for Revenues of Potentially Affected Entities

Segment	Size	No. of Firms	Mean Revenue (million 2019$)	Median Revenue (million 2019$)
Production	Small	836	$230	$11
	Not Small	78	$19,000	$1,300
Processing	Small	88	$180	$11
	Not Small	61	$27,000	$6,100
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 oil and natural gas wells for an operator completed in 2019 and dividing by the average number of wells per site in the Enverus data (~1.33 wells per wellsite). 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 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. To approximate the impact of state requirements on facility level costs relative to baseline, Colorado, California, New Mexico, and Pennsylvania facilities were removed from the well site counts, and Colorado and California were removed from the processing plant and compressor station counts, since these facilities are assumed to have requirements in the baseline that are at least as stringent as the proposed rule. See Section 2.2.3 for more information about the inclusion of state programs in the baseline.

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 pumps, pneumatic controllers, storage vessels, and liquids unloading for well sites; equipment leaks, reciprocating compressors, and dry seal centrifugal compressors for processing plants; and reciprocating compressors, dry/wet seal centrifugal compressors and pneumatic pumps/controllers 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 equipment counts per facility were used to estimate site-level compliance costs for this analysis. Median compliance costs by segment and firm size are presented in Table 4-15, both with and without expected revenue from natural gas recovery included.

Table 4-15 Distribution of Estimated Compliance Costs across Segment and Firm Size Classes (2019$)

Segment	Size	No. of Firms	Median Cost without Product Recovery	Median Cost with Product Recovery
Production	Small	836	$40,000	$39,000
	Not Small	78	$180,000	$170,000
Processing	Small	88	-$4,800	-$9,100
	Not Small	61	-$9,700	-$18,000
Gathering and Boosting	Small	123	$4,400	-$110
	Not Small	77	$11,000	-$280
Transmission and Storage	Small	50	$1,900	$1,300
	Not Small	82	$7,600	$5,200

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

4.3.4.2 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[98]. In the production segment, when expected revenues from natural gas product recovery are included, 206 small entities (25 percent) have cost-to-sales ratios greater than 1 percent, and of those, 79 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 220 (26 percent); 79 of those small entities (9 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% regardless of whether expected revenues from natural gas recovery are included. 1 parent companies (1%) has a cost-to-sales ratio greater than 1 percent when expected revenues from natural gas recovery are excluded (none do when they are included). In the transmission and storage segment, no entity has a CSR greater than either 1 percent or 3 percent regardless of

[98] 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.

whether expected revenues from product recovery are included. The results for all segments are summarized in Table 4-16.

Table 4-16 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	836		836	
	Greater than 1%	220	26%	206	25%
	Greater than 3%	79	9%	79	9%
Processing	All	88		88	
	Greater than 1%	0	0%	0	0%
	Greater than 3%	0	0%	0	0%
Gathering and Boosting	All	123		123	
	Greater than 1%	1	1%	0	0%
	Greater than 3%	0	0%	0	0%
Transmission and Storage	All	50		50	
	Greater than 1%	0	0%	0	0%
	Greater than 3%	0	0%	0	0%

4.3.5 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 2023 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 2023 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 proposed requirements are in effect.
- It is unknown what equipment is present at each site. The use of equipment 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.

4.3.6 Projected Reporting, Recordkeeping and Other Compliance Requirements

The information to be collected for the proposed 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 1,844 owners and operators that are subject to the rule is approximately 881,777 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 66 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).

4.3.7 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 gas from federal lands. BLM manages the Federal government's onshore subsurface mineral estate, about 700 million acres. BLM also oversees oil and 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 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).

4.3.8 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.[99] Based on the Panel recommendations, as well as comments received in response to the November 2021 proposal, the EPA is proposing, or taking comment on, several regulatory alternatives that could accomplish

[99] See document ID EPA-HQ-OAR-2021-0317-0074.

the stated objectives of the Clean Air Act while minimizing any significant economic impact of the proposed rule on small entities. Discussion of those alternatives is provided below.

4.3.8.1 Fugitive Emissions Requirements

As described in the preamble to the supplemental proposal,[100] the EPA is proposing certain changes to the fugitive emissions standards proposed for NSPS OOOOb in the November 2021 proposal. The EPA believes that two of these proposed changes will reduce impacts on small businesses: (1) requiring OGI monitoring for well sites and centralized production facilities following the monitoring plan required in proposed 40 CFR 60.5397b instead of requiring the procedures being 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 proposed changes below.

In the supplemental proposal, 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 proposing to require OGI surveys following the procedures specified in the proposed regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21. This proposed change is consistent with the requirements for OGI surveys found in NSPS OOOOa at 40 CFR 60.5397a. This proposed change is a result of the extensive comments the EPA received from oil and 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.[101] 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 proposing requirements within NSPS OOOOb at 40 CFR 60.5397b in lieu of the procedures in Appendix K for fugitive

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[100] See preamble Section IV.A.
[101] See preamble Section IV.A. and see Document ID Nos. EPA-HQ-OAR-2021-0317-0579, EPA-HQ-OAR-2021-0317-0743, EPA-HQ-OAR-2021-0317-0764, EPA-HQ-OAR-2021-0317-0777, EPA-HQ-OAR-2021-0317-0782, EPA-HQ-OAR-2021-0317-0786, EPA-HQ-OAR-2021-0317-0793, EPA-HQ-OAR-2021-0317-0802, EPA-HQ-OAR-2021-0317-0807, EPA-HQ-OAR-2021-0317-0808, EPA-HQ-OAR-2021-0317-0810, EPA-HQ-OAR-2021-0317-0814, EPA-HQ-OAR-2021-0317-0817, EPA-HQ-OAR-2021-0317-0820, EPA-HQ-OAR-2021-0317-0831, EPA-HQ-OAR-2021-0317-0834, and EPA-HQ-OAR-2021-0317-0938.

emissions monitoring at well sites or centralized production facilities. See section VI of the preamble for additional information on what the EPA is proposing 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 supplemental proposal 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 proposing 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,[102]
- Well sites with only two or more wellheads and no other major production and processing equipment, and
- Well sites 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, including centralized production facilities.

[102] 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 soliciting comment on this definition for small well sites, including whether additional metrics should be used beyond equipment counts, as well as the proposed standards and requirements for this subcategory of sites.

The EPA is proposing these distinct subcategories of well sites after consideration of comments on the November 2021 proposal that stated the proposed 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 proposing specific monitoring frequency and techniques as the BSER for each well site subcategory individually. For example, the EPA is proposing the use of sensory monitoring techniques (AVO) 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 proposed 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 propose allowing 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 proposed 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. AVO inspections 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.

4.3.8.2 Alternative Technology

As described in the preamble to the supplemental proposal,[103] the EPA is proposing changes to the November 2021 proposal alternative technology requirements for NSPS OOOOb. The proposed 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 proposed in NSPS OOOOb. The EPA believes these proposed changes will reduce impacts on small businesses.

Specifically, the EPA is proposing 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 LDAR, 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 propose alternative screening technology, and that the EPA try to minimize significant additional reporting and recordkeeping requirements. In accordance with these recommendations, the EPA is proposing changes that are intended to support 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 proposed "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 is proposing to allow owners and operators the option of using continuous monitoring technologies as an alternative to periodic screening and are proposing long- and short-term emissions rate thresholds that would trigger corrective action as well as monitoring plan requirements for owners and operators that choose this approach. 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 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.

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[103] See preamble section IV.B.

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.

4.3.8.3 Associated Gas

As described in the preamble to the supplemental proposal,[104] the EPA is proposing certain changes to the requirements for oil wells with associated gas that were proposed in November 2021 for NSPS OOOOb. These changes include proposing adjustments to the hierarchy of the standard and compliance options. The EPA believes these proposed changes will especially reduce impacts on small businesses.

Specifically, the EPA is proposing to require flaring of all associated gas 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 soliciting comment on what this demonstration should entail and what qualifications constitute an "other qualified individual" in the preamble for this supplemental proposal. The EPA believes this approach will benefit small entities because it still allows for the flaring of associated gas. 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 proposed allowance of flaring in these situations 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.

[104] See preamble section IV.F.

4.3.8.4 Pneumatic Controller and Pneumatic Pump Requirements

As described in the preamble to the supplemental proposal,[105] the EPA is proposing certain clarifications and changes to the pneumatic controller and pneumatic pumps emissions requirements included in the November 2021 proposal. The EPA is seeking specific solicitations for comment to understand any information that may dispute the conclusions the EPA has made with regards to technical feasibility of the proposed zero-emitting standards. The EPA believes this information will help us further understand the impacts on small businesses.

Through the SBAR Panel outreach, SERs stated that zero emission controllers are not feasible at wells sites or other locations without reliable electricity and 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. EPA and Advocacy recommended that the EPA only propose zero emission standards for pneumatic 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.[106]

For pneumatic 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 pneumatic controllers other than using electricity. Therefore, the proposed NSPS OOOOb does not include any alternative non-zero emission standards for pneumatic controllers.

For pneumatic pumps, the proposed rule recognizes that at sites without access to electricity, there could be situations where it is technically infeasible to use a pump that is not driven by natural gas. As a result, the EPA is proposing to include a tiered structure in the rule that would allow flexibility based on site-specific conditions. At sites without access to electricity, if a demonstration is made that it is technically infeasible to use a pneumatic pump that is not driven by natural gas, the rule would allow the use of a natural gas-driven pump, provided that the emissions are captured and routed to a process, which EPA understands to

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[105] See preamble Sections IV.D and IV.E.

achieve 100 percent reduction of methane and VOC. Such an infeasibility determination is not allowed if the site has access to electricity. This means the proposed rule would prohibit the use of natural gas-driven pumps at sites with access to electricity.

The EPA is requesting information that may dispute the conclusion that there is a technically feasible option that does not emit methane or VOC available for all sites in all segments for pneumatic controllers and pneumatic pumps. Some commenters raised concerns about specific situations that may make individual technologies impracticable to implement (e.g., the inability of solar-powered controller systems to meet the needs at certain remote locations that do not have access to electricity). Although the EPA will consider any additional information commenters may submit about such situations, the EPA notes that there are multiple options for meeting the proposed zero-emission standard and that limitations on the use of one technology at any given site does not mean that other options for meeting the standard are unavailable. As a result, the EPA is particularly interested in understanding whether there are site characteristics that would make every zero-emitting option (e.g., electric controllers powered by the grid or by solar power; instrument air systems powered by the grid, a generator, or by solar power; collecting the emissions and routing them to a process; self-contained controllers, etc.) technically infeasible at the site.

The proposed requirements and solicitations for comment are responsive to SER's statements and concerns about technical feasibility. The EPA believes the solicitations for comment will help continue the dialogue with small entity stakeholders to help the EPA more fully understand the impacts and feasibility challenges on small businesses.

4.3.8.5 Reciprocating Compressors

As described in the preamble to the supplemental proposal,[107] the EPA is proposing certain changes to the proposed requirements for reciprocating compressors in the November 2021 proposal for NSPS OOOOb. The EPA believes these proposed changes will reduce impacts on small businesses.

Concerns were expressed regarding the EPA's November 2021 proposal that shifted rod packing changeout requirements from a designated schedule of once every 3 years to a

[107] See preamble Section IV.I.

performance standard based on an annual flow measurement. It was further noted that this type of 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 could negatively impact small businesses.

The EPA is proposing changes and specific clarifications to the requirements associated with reciprocating compressor rod packing. Specifically, we are proposing: (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; (3) to allow for monitoring based on 8,760 hours of operation instead of based on a calendar year. We are also proposing regulatory text that clearly defines the required flow rate measurement methods and/or procedures, repair and replacement requirements, and recordkeeping and reporting requirements. For the alternative option of routing rod packing emissions to a process via a CVS under negative pressure, we are proposing to remove the negative pressure requirement. These changes take into account comments received on the November 2021 proposal.

The EPA believes this approach will particularly benefit 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. The proposed change for monitoring based on 8,760 hours of operation will ensure that undue burden is not placed on owners and operators where compressors are not operational for multiple months or are used intermittently and this will allow owners and operators the flexibility to stagger maintenance activity throughout the year.

4.4 Employment Impacts of Environmental Regulation

This section presents an overview of the various ways that environmental regulation can affect employment.[108] 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

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[108] Additionally, see Section 4.2.5 for a discussion of the demographic characteristics of oil and natural gas workers and communities.

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 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 in order 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 4.1, the proposed 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.

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 2023 to 2035 relative to a baseline without the proposed NSPS OOOOb and EG OOOOc.

Table 5-1 summarizes the emissions reductions associated with the proposed standards over the 2023 to 2035 period for the NSPS OOOOb, the EG OOOOc, and the NSPS OOOOb and EG OOOOc combined. Table 5-2, Table 5-3, and Table 5-4 present the present value (PV) and equivalent annual value (EAV), estimated using discount rates of 3 and 7 percent, of the changes in quantified benefits, costs, and net benefits, as well as the emissions reductions relative to the baseline for the proposed NSPS OOOOb, for the proposed EG OOOOc, and the proposed NSPS OOOOb and EG OOOOc, respectively. These values reflect an analytical time horizon of 2023 to 2035, 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 proposal.

Table 5-1 Projected Emissions Reductions under the Proposed NSPS OOOOb and EG OOOOc across Regulatory Options, 2023–2035

		Emissions Changes			
Regulatory Option	Proposed Requirements	Methane (millions short tons)	VOC (millions short tons)	HAP (millions short tons)	Methane (million metric tons CO_2 Eq. using GWP=25)
Less Stringent Option					
	NSPS OOOOb	1.8	1.3	0.05	42
	EG OOOOc	11	2.3	0.1	250
	Total	**13**	**3.6**	**0.2**	**290**
Proposed Option					
	NSPS OOOOb	8.1	2.9	0.11	180
	EG OOOOc	28	6.8	0.28	620
	Total	**36**	**10**	**0.39**	**810**
More Stringent Option					
	NSPS OOOOb	9.7	3.5	0.13	220
	EG OOOOc	28	7	0.28	630
	Total	**37**	**10**	**0.41**	**850**

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

Table 5-2 Projected Benefits, Compliance Costs, and Emissions Reductions across Regulatory Options under the Proposed NSPS OOOOb, 2023–2035 (million 2019$)

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[a]				
Less Stringent	$2,000	$190	$2,000	$190
Proposal	$11,000	$1,000	$11,000	$1,000
More Stringent	$11,000	$1,000	$11,000	$1,000
	3 Percent Discount Rate		**7 Percent Discount Rate**	
	PV	EAV	PV	EAV
Net Compliance Costs				
Less Stringent	$3,200	$300	$2,500	$280
Proposal	$3,300	$360	$3,000	$360
More Stringent	$3,800	$360	$3,000	$360
Compliance Costs				
Less Stringent	$3,400	$320	$2,500	$300
Proposal	$4,400	$460	$3,700	$440
More Stringent	$4,900	$460	$3,700	$450
Value of Product Recovery				
Less Stringent	$170	$16	$14	$14
Proposal	$1,000	$99	$730	$88
More Stringent	$1,100	$99	$730	$88
Net Benefits				
Less Stringent	-$1,200	-$110	-$470	-$95
Proposal	$7,600	$670	$7,900	$670
More Stringent	$7,100	$670	$7,900	$670
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent	1,800,000			
Proposal	8,100,000			
More Stringent	9,700,000			
$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons)[b]:				
Less Stringent	1,300,000			
Proposal	2,900,000			
More Stringent	3,500,000			
HAP benefits from reducing HAP emissions by (in short tons):				
Less Stringent	49,000			
Proposal	110,000			
More Stringent	130,000			
Visibility benefits				
Reduced vegetation effects				

Notes: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[a] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane ($SC\text{-}CH_4$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th

percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; see Table 3-9 for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). All net benefits are calculated using climate benefits discounted at 3 percent.
[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix C.

Table 5-3 Projected Benefits, Compliance Costs, and Emissions Reductions across Regulatory Options under the Proposed EG OOOOc, 2023–2035 (million 2019$)

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[a]				
Less Stringent	$15,000	$1,400	$15,000	$1,400
Proposal	$37,000	$3,500	$37,000	$3,500
More Stringent	$37,000	$3,500	$37,000	$3,500
	3 Percent Discount Rate		**7 Percent Discount Rate**	
	PV	EAV	PV	EAV
Net Compliance Costs				
Less Stringent	$4,900	$460	$3,600	$430
Proposal	$11,000	$990	$8,700	$1,000
More Stringent	$11,000	$1,000	$9,000	$1,100
Compliance Costs				
Less Stringent	$6,300	$600	$4,600	$550
Proposal	$14,000	$1,300	$11,000	$1,300
More Stringent	$15,000	$1,400	$12,000	$1,400
Value of Product Recovery				
Less Stringent	$1,400	$130	$990	$120
Proposal	$3,600	$340	$2,500	$300
More Stringent	$3,600	$340	$2,600	$310
Net Benefits				
Less Stringent	$9,900	$930	$11,000	$960
Proposal	$26,000	$2,500	$28,000	$2,400
More Stringent	$26,000	$2,500	$28,000	$2,400
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent	11,000,000			
Proposal	28,000,000			
More Stringent	28,000,000			
$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons)[b,c]:				
Less Stringent	2,300,000			
Proposal	6,800,000			
More Stringent	6,900,000			

HAP benefits from reducing HAP emissions by (in short tons):	
Less Stringent	110,000
Proposal	280,000
More Stringent	280,000
Visibility benefits	
Reduced vegetation effects	

Notes: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[a] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane ($SC\text{-}CH_4$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average $SC\text{-}CH_4$ at a 3 percent discount rate, but the Agency does not have a single central $SC\text{-}CH_4$ point estimate. We emphasize the importance and value of considering the benefits calculated using all four $SC\text{-}CH_4$ estimates; see Table 3-10 for the full range of $SC\text{-}CH_4$ estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of $SC\text{-}CH_4$ estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). All net benefits are calculated using climate benefits discounted at 3 percent.
[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix C.
[c] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

Table 5-4 Projected Benefits, Compliance Costs, and Emissions Reductions across Regulatory Options under the Proposed NSPS OOOOb and EG OOOOc, 2023–2035 (million 2019$)

	3 Percent Discount Rate			
	PV	EAV	PV	EAV
Climate Benefits[a]				
Less Stringent	$17,000	$1,600	$17,000	$1,600
Proposal	$48,000	$4,500	$48,000	$4,500
More Stringent	$48,000	$4,500	$48,000	$4,500
	3 Percent Discount Rate		**7 Percent Discount Rate**	
	PV	EAV	PV	EAV
Net Compliance Costs				
Less Stringent	$8,200	$770	$6,000	$710
Proposal	$14,000	$1,400	$12,000	$1,400
More Stringent	$15,000	$1,400	$12,000	$1,400
Compliance Costs				
Less Stringent	$9,700	$920	$7,100	$840
Proposal	$19,000	$1,800	$15,000	$1,800
More Stringent	$20,000	$1,800	$15,000	$1,800
Value of Product Recovery				
Less Stringent	$1,600	$150	$1,000	$130
Proposal	$4,600	$440	$3,300	$390
More Stringent	$4,700	$440	$3,300	$390

Net Benefits				
Less Stringent	$8,600	$810	$11,000	$870
Proposal	$34,000	$3,200	$36,000	$3,100
More Stringent	$33,000	$3,100	$36,000	$3,100
Non-Monetized Benefits				
Climate and ozone health benefits from reducing methane emissions by (in short tons):				
Less Stringent		13,000,000		
Proposal		36,000,000		
More Stringent		37,000,000		
$PM_{2.5}$ and ozone health benefits from reducing VOC emissions by (in short tons)[b,c]:				
Less Stringent		3,600,000		
Proposal		9,700,000		
More Stringent		10,000,000		
HAP benefits from reducing HAP emissions by (in short tons):				
Less Stringent		160,000		
Proposal		390,000		
More Stringent		410,000		
Visibility benefits				
Reduced vegetation effects				

Notes: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[a] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; see Table 3-8 for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). All net benefits are calculated using climate benefits discounted at 3 percent.
[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix C.
[c] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

The following table shows the total emissions reductions and the PV and EAV of net compliance costs over the 2023 to 2035 period. The projected net compliance costs for reciprocating compressors 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, many of the reciprocating compressors are in the transmission and storage segment. As discussed in previous oil and natural gas NSPS RIAs, operators in the transmission and storage segment 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, 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 cost reductions presented above may be underestimated.

Table 5-5 Projected Emissions Reductions, Climate Benefits, and Compliance Costs (millions 2019$) for Incrementally Affected Sources under the Proposed NSPS OOOOb and EG OOOOc Option, 2023 to 2035

	Nationwide Emissions Reductions			Costs and Benefits (EAV, million 2019$)			
Source	Methane (metric tons CO2e)	VOC[a] (short tons)	HAP (short tons)	Climate Benefits[b]	Capital Cost	Annualized Cost, without Product Recovery	Annualized Cost, with Product Recovery
Well Site Fugitives	83,000,000	1,000,000	38,000	$460	$23	$510	$470
Gathering and Boosting Station Fugitives	15,000,000	190,000	7,100	$85	$1.7	$34	$28
Transmission and Storage Compressor Station Fugitives	19,000,000	23,000	680	$100	$4.7	$19	$12
Natural Gas Processing Plant Leaks	3,700,000	19,000	710	$21	-$1.1	$2.4	$1.0
Pneumatic Devices	540,000,000	6,400,000	240,000	$3,000	$910	$570	$360
Reciprocating Compressors	88,000,000	740,000	28,000	$490	$17	$28	-$4.6
Centrifugal Compressors	49,000,000	400,000	42,000	$280	$0	$49	$31
Liquids Unloading	5,700,000	70,000	2,600	$32	$0	$8	$6.2
Storage Vessels	3,900,000	820,000	31,000	$22	$80	$190	$190

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. The equivalent annualized values (EAV) in the table are calculated over the 2023 to 2035 period using a 3% discount rate.

[a] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

[b] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; see Table 3-8 for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B presents the results of a sensitivity analysis using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). All net benefits are calculated using climate benefits discounted at 3 percent.

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 proposed 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. Mispecifications 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, though we may attempt to do so in advance of the final rulemaking. 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.

Equipment at Well Sites: A major assumption embedded in the analysis is that equipment at well sites remains fixed over time. This assumption simplifies the analysis, but it ignores the possibility that as production decreases at a well site, equipment may be removed from the site. As a result, impacts may be overstated, particularly in the later years of the analysis horizon. We will continue to assess the validity of this assumption and contemplate alternatives in advance of the final rule analysis.

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 2026. 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 2023, to represent the full first-year facilities are affected by this action, through 2035, 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 2035 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 2035 would introduce substantial and increasing uncertainties in the projected impacts of the proposal. That said, some amount of both benefits and costs would likely continue after 2035, and we note that toward the end of our analytical time horizon, undiscounted net costs are relatively steady from year to year (Table 2-9) 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 2035, 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 proposed requirements than those in the rest of the country, both in the baseline due to previous rulemakings and in the proposal. 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.[109] We do not reflect those reduced requirements in the baseline in this RIA, nor do we reflect that the same reduced requirements are being proposed 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 proposed 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

[109] 83 FR 10628.

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 overestimate both the benefits and costs of the proposed 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 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 4.1.5.

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. Appendix B presents the results of a sensitivity analysis using newly developed SC-CH_4 estimates that address updating recommendations of the National Academies of Sciences, Engineering, and Medicine (2017).

Monetized VOC-related ozone benefits: The illustrative screening analysis described in Illustrative Screening Analysis of Monetized VOC-Related Ozone Health Benefits 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 segment 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 ≤ 40ppb and below (U.S. EPA, 2020b). 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 (NRC, 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 TSD for the Final Revised Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Update titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* (U.S. EPA, 2021g).

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 proposed requirements in this RIA. For a discussion of these requirements, see Section 2.1.2.

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 assess are subject to increased uncertainty as compared to overall exposure and risk estimates.

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APPENDIX A ADDITIONAL INFORMATION ON COST AND EMISSIONS ANALYSIS

In this appendix, we provide additional information on topics related to the development of well site activity data and cost estimation. Specifically, we describe in detail how the 2016 ICR data was used to calculate equipment bin proportions and average equipment factors for well sites and how equipment counts at well sites were calibrated to the GHGI for the base year.

A.1 Calculation of Equipment Bin Proportions and Average Equipment Factors for Well Sites from 2016 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,[110] 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.

[110] 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.

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 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 six equipment/tank categories: (1) no equipment or tanks; (2) no equipment with storage tanks; (3) one piece of major equipment without tanks; (4) one piece of major equipment with tanks; (5) more than one piece of major equipment without tanks; and (6) more than one piece of major equipment with tanks.

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. To facilitate calibration with the GHGI, which has activity data for wells but not well sites, we calculate average equipment counts per oil well and per gas well. To do the per-well calculation, equipment counts at each site are allocated to wells in proportion to the number of oil and gas wells at the sites, and then aggregated by production level, well count bin, and equipment category. The aggregated equipment counts are then divided by aggregate counts of oil and gas wells for all sites to arrive at equipment count averages per well for the sites in the final data set.

The results for well site proportions, stratified by production type and level and well count bin, are presented in Table A-1. A significant portion of sites, particularly single wellhead oil sites, do not have any major equipment or tanks. Larger sites, both in terms of production levels and well counts, tend to have more equipment for both site types.

Table A-1 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
(1) No major equipment or tanks	37%	4%	33%	1%	58%	11%	44%	3%
(2) No major equipment with tanks	5%	14%	2%	1%	9%	24%	2%	6%
(3) One piece of major equipment without tanks	21%	4%	12%	4%	2%	1%	8%	1%
(4) One piece of major equipment with tanks	2%	5%	1%	9%	0%	0%	1%	16%
(5) Two or more pieces of major equipment without tanks	30%	30%	39%	6%	24%	44%	23%	7%
(6) Two or more pieces of major equipment with tanks	5%	43%	13%	79%	6%	20%	22%	67%

The results for well site equipment averages, stratified by production level, well count bin, and equipment category, are presented in Table A-2. Typically, non-low production sites tend to have more equipment 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. Also, for the same well type, well count bin, and equipment category, multi-well sites tend to have fewer pieces of equipment per well.

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

Well Type	Site Production Level	Site Well Count Bin	Equipment Category	Equipment Count Per Well			
				Separators	Compressors	Dehydrators	Tanks
Gas	Low	Single	(1)	-	-	-	-
			(2)	-	-	-	1.48
			(3)	0.97	0.02	0.01	-
			(4)	1.20	0.86	0.22	-
			(5)	0.99	0.01	0.01	1.50
			(6)	1.87	0.38	0.13	2.03
		Multi	(1)	-	-	-	-
			(2)	-	-	-	0.67
			(3)	0.29	0.01	0.00	-
			(4)	0.85	0.32	0.01	-
			(5)	0.34	0.00	0.01	0.64
			(6)	0.91	0.15	0.05	0.86
	Non-low	Single	(1)	-	-	-	-
			(2)	-	-	-	2.22
			(3)	0.94	0.04	0.02	-
			(4)	1.74	0.51	0.17	-
			(5)	0.95	0.01	0.04	1.66
			(6)	1.82	0.50	0.19	2.23
		Multi	(1)	-	-	-	-
			(2)	-	-	-	2.70
			(3)	0.26	0.02	0.00	-
			(4)	1.03	0.04	0.03	-
			(5)	0.32	0.02	0.00	0.91
			(6)	1.00	0.08	0.02	0.92

Oil	Low	Single	(1)	-	-	-	-
			(2)	-	-	-	2.17
			(3)	0.84	0.15	0.01	-
			(4)	1.27	0.86	0.13	-
			(5)	0.98	0.02	0.00	2.16
			(6)	1.94	0.35	0.05	3.77
		Multi	(1)	-	-	-	-
			(2)	-	-	-	0.61
			(3)	0.21	0.03	0.00	-
			(4)	0.58	0.07	0.07	-
			(5)	0.21	0.00	0.00	0.48
			(6)	0.50	0.05	0.01	0.70
	Non-low	Single	(1)	-	-	-	-
			(2)	-	-	-	3.23
			(3)	0.99	0.01	0.00	-
			(4)	1.62	0.54	0.08	-
			(5)	0.99	0.01	0.00	4.08
			(6)	2.24	0.51	0.06	4.70
		Multi	(1)	-	-	-	-
			(2)	-	-	-	1.00
			(3)	0.12	0.00	0.01	-
			(4)	0.77	0.01	0.00	-
			(5)	0.25	0.01	0.00	1.56
			(6)	1.04	0.12	0.02	2.01

A.2 Equipment Count Calibration at Well Sites

The equipment count calibration performed for this analysis ensures that base year estimates of certain types of equipment at well sites matches, in aggregate, values from the GHGI. Equipment count estimates from other sources, such as the 2016 ICR and the API survey data, are used to capture important dimensions of heterogeneity in equipment across different types of well sites not captured by the GHGI (e.g., low producing versus non-low producing wells, single well sites versus multi-well sites, etc.). Having described the use of the 2016 ICR data in the preceeding section, we now describe our use of the API survey data and other elements of the calibration procedure.

Since the 2016 ICR data lacks information on process heaters and heater-treaters at well sites, we use the API survey data to fill in the gap. The first step is to determine the proportion of well sites that have exactly one separator, compressor, or dehydrator and either a process heater or a heater-treater, since the fugitive emissions monitoring requirements are different for single well sites with one piece of major equipment and those with more than one.[111] Within the API survey data, there are 451 oil sites and 724 gas sites with exactly one separator, compressor, or dehydrator. Of the oil sites, 67% have a heater-treater, while 40% of the gas sites have a process heater.[112] As a result, we shift 67% of oil sites, and 40% of gas sites, estimated to have one piece of major equipment by our analysis of the 2016 ICR to the "more than one piece of major equipment" category.[113] The next step is to come up with an initial estimate of the number of heater-treaters and process heaters per site. For API survey sites with exactly one separator, compressor, or dehydrator and at least one heater-treater, there are an average of 1.08 heater-treaters per well at single wellhead oil sites, and 0.73 heater-treaters per well at multi-wellhead oil sites. For sites with more than one separator, compressor, and dehydrator, there are an average of 0.88 heater-treaters per well at single wellhead oil sites, and 0.54 heater-treaters per well at multi-wellhead oil sites. For sites with exactly one separator, compressor, or dehydrator and at least one process heater, there is an average of one heater-treaters per well at gas sites. For sites with more than one separator, compressor, and dehydrator, there are an average of 0.28 process heaters per well at single wellhead gas sites, and 0.02 process heaters per well at multi-wellhead gas sites.

Once equipment count averages have been calculated for separators, compressors dehydrators, heaters, and heater-treaters (stratified by well type, site production level, site well count bin, and site equipment category), those values are merged into the base year well site group activity data. The total, nationwide counts of equipment implied by our application of the 2016 ICR/API survey data to the activity data are then calculated. Finally, the per-well equipment counts are scaled, uniformly across all site production level, site well count bin, and site equipment category permutations, by the ratio of the equipment counts implied by the aggregate GHGI per-well equipment factors applied to our base year activity data to the

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[111] Due to a lack of sufficient data, we assume that sites without separators, compressors, and dehydrators represent wellhead-only sites, and therefore do not have heater-treaters or process heaters either.

[112] We restrict the API survey sample to exclude sites in Alaska, which are much larger than most of the the other sites in the sample. We also consider heater-treaters only at oil sites and process heaters only at gas sites to maintain consistency with the GHGI, which attributes all process heaters to gas production and all heater-treaters to oil production.

[113] The API survey data does not distinguish sites by production level and the number of multi-well sites with exactly one separator, compressor, or dehydrator is small, so we apply these proportions uniformly across all site types in the ICR summary proportions data.

aggregate equipment counts implied by our application of the 2016 ICR/API survey data.[114] This ensures that our aggregate per-well equipment counts match the GHGI in 2019.

[114] In math notation, the calibrated per-well equipment counts can be expressed as follows:

$$EqCnt_{t,b,c}^{cal} = \left(\frac{EqCnt^{GHGI} \cdot Wells_t^{ENV}}{TotEqCnt_t^{ICR/ENV}}\right) * EqCnt_{t,b,c}^{ICR},$$

where t denotes well type, b denotes well count bin, c denotes equipment category, cal denotes a calibrated value, $GHGI$ denotes a value based on the GHGI, ENV denotes a value based on analysis of the base year Enverus well data, ICR denotes a value based on analysis of the 2016 ICR and the API survey data, ICR/ENV denotes a value based on the application of the analysis of the 2016 ICR and the API survey data to the analysis of the base year Enverus well data, $EqCnt$ denotes a per-well equipment count for separators, compressors, dehydrators, heater-treaters, and process heaters, $Wells$ denotes the total number of wells, and $TotEqCnt$ denotes an aggregate equipment count across the entire collection of sites.

APPENDIX B SENSITIVITY ANALYSIS OF MONETIZED CLIMATE BENEFITS

In this Appendix, we present the results of a sensitivity analysis of the monetized climate benefits of this proposal using estimates of the social cost of methane (SC-CH_4) newly developed by EPA. As described below, these new SC-CH_4 estimates are based on recent research addressing recommendations for updating estimates of the SC-GHG from the National Academies of Sciencies, Engineering, and Medicine (National Academies, 2017). Section B.1 describes the methodological updates underlying the new estimates relative to the interim SC-CH_4 estimates used in Chapter 3 of this RIA. Section B.2 presents the monetized climate benefits under the proposed NSPS OOOOb and EG OOOOc using the updated SC-CH_4 estimates.

B.1 Updated Estimates of the Social Cost of Methane

As discussed in Section 3.2 of this RIA, in January 2017 the National Academies published a final report, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*, that responded to a U.S. Government-requested review of the IWG's SC-CO_2 estimates and request for advice on approaching future updates to ensure that the estimates continue to reflect the best available science and methodologies. The National Academies' final report provided a comprehensive set of recommendations for updating estimates of the social cost of carbon, including specific criteria for future updates to the estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs for multiple components of the estimation process (National Academies, 2017). Since that time, the research community has made considerable progress in developing new data and methods for bringing SC-GHG estimates closer to the current frontier of climate science and economics and addressing many of the National Academies' (2017) recommendations. In this Appendix the EPA uses new SC-CH_4 estimates derived from the recent advances in the scientific literature on climate change and its economic impacts to conduct a sensitivity analysis of the climate benefits of this proposed rulemaking.

The SC-CH_4 estimates used in this sensitivity analysis are taken from EPA's September 2022 *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* (EPA 2022, external review draft), which has been included as supporting material for this RIA in the docket. The SC-CH_4 estimates reflect numerous methodological updates relative to the SC-CH_4 estimates used in Section 3.2 of this RIA. All the modeling inputs and updates are explained at length in EPA (2022) and are briefly summarized here. Consistent with the National Academies (2017) near-term updating recommendations, the SC-CH_4 values were estimated using a modular updating approach in which the methodology underlying each of the four components, or modules, of the SC-GHG estimation process — socioeconomics and emissions, climate, damages, and discounting — is updated by drawing on the latest research and expertise from the scientific disciplines relevant to that component. 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 Social Cost of Carbon Initiative (Rennert et al., 2022a). The climate module relies on the Finite Amplitude Impulse Response (FaIR) model (Millar et al., 2017; Smith et al., 2018, 2021), a widely used simple Earth system model recommended by the National Academies, which captures the relationships between GHG emissions, atmospheric GHG concentrations, and global mean surface temperature change. The socioeconomic projections and outputs of the climate module are used as inputs to the damage module to estimate monetized future damages from temperature change. Based on a review of available studies and approaches to damage function estimation, the damages module is composed of three separate damage functions. They are:

1. a subnational-scale, sectoral damage function estimation (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (CIL 2022; Carleton et al., 2022; Rode et al., 2021)),
2. a country-scale, sectoral damage function estimation (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF's Social Cost of Carbon Initiative (Rennert et al., 2022b)), and
3. a meta-analysis-based global damage function estimation (based on Howard and Sterner (2017)).

Finally, in the discounting module the projected stream of future climate damages are discounted back to the year of emissions using a set of calibrated dynamic discount rates following the Newell et al. (2022) calibration approach, as applied in Rennert et al. (2022a, 2022b). This approach uses the Ramsey (1928) discounting formula in which the parameters are calibrated such that the decline in the certainty-equivalent discount rate schedule matches the latest empirical evidence on interest rate uncertainty estimated by Bauer and Rudebusch (2020,

2021) and such that the average of the certainty-equivalent discount rate over the first decade matches a specified 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 interest rate data. This approach results in three dynamic discount rate paths and is 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 consistent with theory and empirical evidence on consumption rate uncertainty. Finally, the value of risk aversion associated with marginal GHG emissions is explicitly incorporated into the modeling following the economic literature.

The estimation process outlined above generates nine separate distributions of the SC-CH_4 for a given year, the product of three damage modules and three near-term target discount rates. As described in EPA (2022), to produce a range of estimates that reflects the uncertainty in the estimation exercise while providing a manageable number of estimates for policy analysis, the multiple lines of evidence on damage modules was combined by averaging the results across the three damage module specifications. The resulting SC-CH_4 estimates for each year of the analysis period for this proposed rule are presented in Table B-1. Comparing the estimates presented in Table B-1 with the average SC-CH_4 estimates resulting from the constant discount rates presented in Table 3-3, for all emissions years the range of the updated estimates is higher in magnitude than the IWG's recommended interim SC-CH_4 estimates. For example, for emissions occurring in 2035, the updated SC-CH_4 values range from $2,300 to $3,600 per metric ton CH_4 (in 2019 dollars), whereas the average SC-CH_4 values using the constant discount rates presented in Table 3-3 range from $1,100 to $2,800 per metric ton CH_4 (in 2019 dollars).

Table B-1 Updated Estimates of the Social Cost of CH_4, 2023–2035 (in 2019$ per metric ton CH_4)

	Near-Term Ramsey Discount Rate		
Year	**2.5%**	**2.0%**	**1.5%**
2023	$1,400	$1,900	$2,500
2024	$1,500	$1,900	$2,600
2025	$1,600	$2,000	$2,700
2026	$1,600	$2,100	$2,800
2027	$1,700	$2,200	$2,900
2028	$1,800	$2,200	$3,000
2029	$1,800	$2,300	$3,000
2030	$1,900	$2,400	$3,100
2031	$2,000	$2,500	$3,200
2032	$2,100	$2,500	$3,300
2033	$2,100	$2,600	$3,400
2034	$2,200	$2,700	$3,500
2035	$2,300	$2,800	$3,600

Source: EPA (2022).
Note: 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 Table A.4.1 of EPA (2022) and at: www.epa.gov/environmental-economics/scghg. These SC-CH_4 values are 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 methodological updates underlying the SC-CH_4 estimates presented in Table B-1 reflect conservative methodological choices, and, given both these choices and the numerous categories of damages that are not currently quantified and other model limitations, likely underestimate the marginal damages from methane emissions. Detailed discussion of omitted categories of climate impacts and associated damages and other modeling limitations is provided in EPA (2022).

As a member of the IWG, EPA will continue to participate in the IWG's work under E.O. 13990. EPA will also continue to independently review developments in the literature, including more robust methodologies for estimating the magnitude of the various direct and indirect damages from GHG emissions, and look for opportunities to further improve SC-GHG estimation going forward. Information about the forthcoming peer review of the EPA report detailing the SC-CH_4 estimates presented above can be found at: www.epa.gov/environmental-economics/scghg.

B.2 Results of the Climate Benefits Sensitivity Analysis

Table B-2 presents the undiscounted annual monetized climate benefits under the proposed NSPS OOOOb and EG OOOOc using the updated SC-CH_4 estimates. Projected methane emissions reductions each year are multiplied by the SC-CH_4 estimate from Table B-1 above for that year. Table B-3 shows the annual monetized climate benefits discounted back to 2021 and the PV and the EAV for the 2023–2035 period under each near-term Ramsey discount rate. In Table B-3, the future benefits in each column are discounted back to 2021 using the corresponding near-term discount rate.[115]

Table B-2 Undiscounted Monetized Climate Benefits Using Updated SC-CH_4 Estimates under the NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions, 2019$)[a]

	Near-Term Ramsey Discount Rate		
Year	**2.5%**	**2.0%**	**1.5%**
2023	$190	$240	$330
2024	$300	$390	$530
2025	$430	$550	$750
2026	$5,200	$6,500	$8,800
2027	$5,400	$6,800	$9,100
2028	$5,600	$7,000	$9,400
2029	$5,800	$7,300	$9,600
2030	$6,000	$7,500	$9,900
2031	$6,300	$7,800	$10,000
2032	$6,500	$8,100	$11,000
2033	$6,800	$8,400	$11,000
2034	$7,100	$8,700	$11,000
2035	$7,300	$9,000	$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 provided in EPA (2022).

[115] Given the relatively short time period of analysis for this proposed rule, the error associated with discounting future benefits back to 2021 using a constant discount rate instead of using the year specific certainty-equivalent discount factor will be small (i.e., resulting in a less than 1% underestimate of the present value of the 2023–2035 emission reductions). See EPA (2022) for more discussion.

Table B-3 Discounted Monetized Climate Benefits Using Updated SC-CH_4 Estimates under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (millions, 2019$)[a]

	Discounted back to 2021		
	Near-Term Ramsey Discount Rate		
Year	**2.5%**	**2.0%**	**1.5%**
2023	$180	$230	$320
2024	$280	$370	$500
2025	$390	$510	$700
2026	$4,600	$5,900	$8,200
2027	$4,600	$6,000	$8,300
2028	$4,700	$6,100	$8,400
2029	$4,800	$6,200	$8,600
2030	$4,800	$6,300	$8,700
2031	$4,900	$6,400	$8,800
2032	$5,000	$6,500	$9,000
2033	$5,100	$6,600	$9,100
2034	$5,100	$6,700	$9,300
2035	$5,200	$6,800	$9,400
PV	$50,000	$65,000	$89,000
EAV	$4,500	$5,700	$7,600

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using updated estimates of the SC-CH_4 provided in EPA (2022).
Note: Totals may not appear to add correctly due to rounding.

Comparing the monetized climate benefits presented in Tables B-2 and B-3 with the results presented in Tables 3-4 and 3-5 using the average SC-CH_4 estimates under each discount rate, for all emissions years the range of the climate benefits resulting from this sensitivity analysis is higher in magnitude than the monetized climate benefits using the IWG's recommended interim SC-CH_4 estimates.[116] For example, this sensitivity analysis projects

[116] The disbenefit of the secondary CO_2 impacts of the rule discussed in Section 3.7 will also be somewhat larger if using the updated SC-CO_2 estimates presented in EPA (2022). However, the estimated disbenefits associated with destroying one metric ton of methane through combustion of emissions at oil and gas sites and releasing the CO_2 emissions in 2023 instead of being released in the future via the methane oxidation process are still found to be small relative to the benefits of flaring. Updating the illustrative analysis provided in Section 3.7 of this RIA with the SC-CO_2 values in EPA (2022), we find the disbenefit is estimated to be about $78 per metric ton CH_4 (based on average SC-CO_2 using the 2% near-term Ramsey discount rate) or about 4 percent of the SC-CH_4 estimate per metric ton for 2023. The analogous estimate for 2035 is $115 per metric ton CH_4 or about 4 percent of the SC-CH_4 estimates per metric ton for 2035. As discussed in Section 3.7, 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 total benefits estimates of this sensitivity analysis presented in this Appendix. Nevertheless, upon consideration of the updated SC-CO_2 estimates presented in EPA (2022), EPA continues to believe that the disbenefits of the secondary CO_2 impacts will be minor compared to the rule's net benefits. The EPA will will continue to follow the scientific literature on this topic and update its methodologies as warranted.

undiscounted monetized climate benefits of \$7.3 billion to \$12 billion (in 2019 dollars) by 2035, whereas the undiscounted monetized climate benefits based on average SC-CH_4 values in Table 3-4 range from \$3.5 billion to \$8.9 billion in 2035. The sensitivity analysis projects the PV and EAV of monetized climate benefits over 2023-2035 using the central 2% near-term Ramsey discount rate to be \$65 billion and \$5.7 billion, respectively, whereas the PV and EAV climate benefits presented in Table 1-6 (using the interim SC-CH_4 values under a constant 3% discount rate) are \$48 billion and \$4.5 billion, respectively.

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APPENDIX C ILLUSTRATIVE SCREENING ANALYSIS OF MONETIZED VOC-RELATED OZONE HEALTH BENEFITS

In this appendix, we present a supplementary screening analysis to estimate potential health benefits from the changes in ozone concentrations resulting from VOC emissions reductions under the proposed rule.[117] As we describe in detail below, the distribution of the change in VOC emissions are subject to significant uncertainties; for this reason, the estimated benefits reported below should not be interpreted as a central estimate and thus are not reflected in the calculated net benefits above. For this analysis, we apply a national benefit-per-ton approach based on photochemical modeling with source apportionment paired with the Environmental Benefits Mapping and Analysis Program (BenMAP) for years between 2023 and 2035 using an April–September average of 8-hr daily maximum (MDA8) ozone metric.

C.1 Air Quality Modeling Simulations

The photochemical model simulations are described in detail in U.S. EPA (2021a) and are summarized briefly in this section. The air quality modeling used in this analysis included annual model simulations for the year 2017. The photochemical modeling results for 2017, in conjunction with modeling to characterize the air quality impacts from groups of emissions sources (i.e., source apportionment modeling) and expected emissions changes due to this proposed rule, were used to estimate ozone benefits expected from this proposed rule in the years 2023–2035.

The air quality model simulations (i.e., model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx version 7.00) (Ramboll Environ, 2016). The CAMx nationwide modeling domain (i.e., the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12×12 km shown in Figure C-1.

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[117] Note that this illustrative analysis does not consider the health and welfare benefits from reducing tropospheric ozone production resulting from CH_4 emissions, which are also not included in estimates of the social cost of methane.

Figure C-1 Air Quality Modeling Domain

C.1.1 Ozone Model Performance

While U.S. EPA (2021a) provides an overview of model performance, we provide a more detailed assessment here specifically focusing on ozone model performance relevant to the metrics used in this analysis. In this section, we report CAMx model performance for the MDA8 ozone across all days in April-September. While regulatory analyses often focus on model performance on high ozone days relevant to the NAAQS (U.S. EPA, 2018a), here we focus on all days in April-September since the relevant ozone metrics used as inputs into BenMAP use summertime seasonal averages. Model performance information is provided for each of the nine National Oceanic and Atmospheric Administration (NOAA) climate regions in the contiguous US, as shown in Figure C-2 and first described by Karl and Koss (1984).[118]

Table C-1 provides a summary of model performance statistics by region. Normalized Mean Bias was within ±10 percent in every region and within ±5 percent in the Northeast, Ohio Valley, South, Southwest, and West regions. Across all monitoring sites, normalized mean bias was -0.2 percent. Normalized mean error for modeled MDA8 ozone was less than ±20 percent in every region except the Northwest where it was 21 percent. Correlation between the modeled and observed MDA8 ozone values was 0.7 or greater in five of the nine regions (Northeast, Upper Midwest, Southeast, South, and West). In the remaining four regions correlation was 0.69 in the Ohio Valley, 0.64 in the Northern Rockies and Plains, 0.46 in the Southwest, and 0.69 in

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[118] Figure obtained from https://www.ncdc.noaa.gov/monitoring-references/maps/us-climate-regions.php.

the Northwest. Across the contiguous U.S. as a whole, the correlation between modeled and measured MDA8 ozone was 0.72.

Figure C-3 displays modeled MDA8 normalized mean bias at individual monitoring sites. This figure reveals that the model has slight overpredictions of mean April-September MDA8 ozone in the southeastern portion of the country and along the Pacific coast and slight underpredictions in the northern and western portions of the country. Time series plots of the modeled and observed MDA8 ozone and model performance statistics across the nine regions were developed.[119] Overall, the model closely captures day to day fluctuations in ozone concentrations, although the model had a tendency to underpredict ozone in the earlier portion of the ozone season (April and May) and overpredict in the later portion of the ozone season (July-September) with mixed results in June. This model performance is within the range of other ozone model applications, as reported in scientific studies (Emery et al., 2017; Simon, Baker, & Phillips, 2012). Thus, the model performance results demonstrate the scientific credibility of our 2017 modeling platform. These results provide confidence in the ability of the modeling platform to provide a reasonable projection of expected future year ozone concentrations and contributions.

[119] Memorandum. *2017 Time Series Plots Supporting the Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*. Prepared by Heather Simon, AQAD/OAQPS/EPA. September 29, 2021.

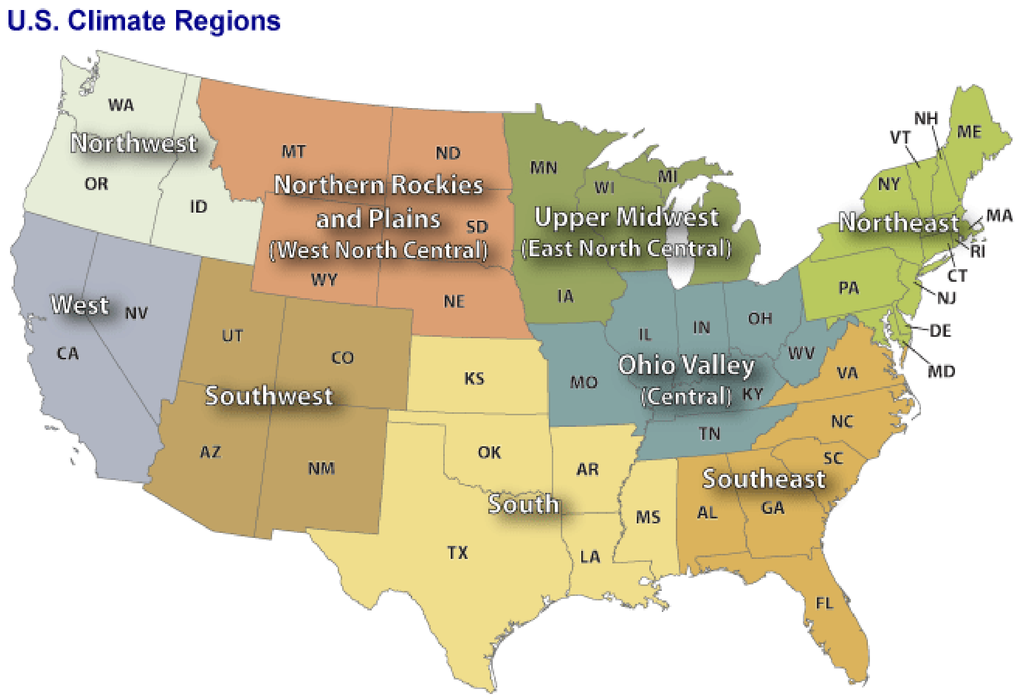

Figure C-2 Climate Regions Used to Summarize 2017 CAMx Model Performance for Ozone

Table C-1 Summary of 2017 CAMx MDA8 ozone model performance for all April–September days

Region	Number of Monitoring Sites	Mean observed MDA8 (ppb)	Mean modeled MDA8 (ppb)	Correlation	Mean bias (ppb)	RMSE (ppb)	Normalized mean bias (%)	Normalized mean error (%)
Northeast	189	42.4	42.5	0.71	0.1	9.1	0.3	17.2
Upper Midwest	107	42.5	39.1	0.70	-3.4	9.1	-8.0	17.2
Ohio Valley	236	45.4	45.8	0.69	0.4	8.3	0.8	14.7
Southeast	177	40.2	43.4	0.76	3.3	8.8	8.2	17.7
South	145	42.0	43.5	0.73	1.5	8.8	3.6	16.7
Northern Rockies and Plains	55	46.8	43.1	0.64	-3.7	9.3	-7.9	16.4
Southwest	117	54.3	52.5	0.46	-1.8	10.2	-3.4	15.5
Northwest	28	41.4	44.0	0.69	2.7	12.4	6.4	21.0
West	200	51.6	50.1	0.74	-1.5	10.3	-2.9	16.1
All	**1258**	**45.4**	**45.3**	**0.72**	**-0.1**	**9.3**	**-0.2**	**16.4**

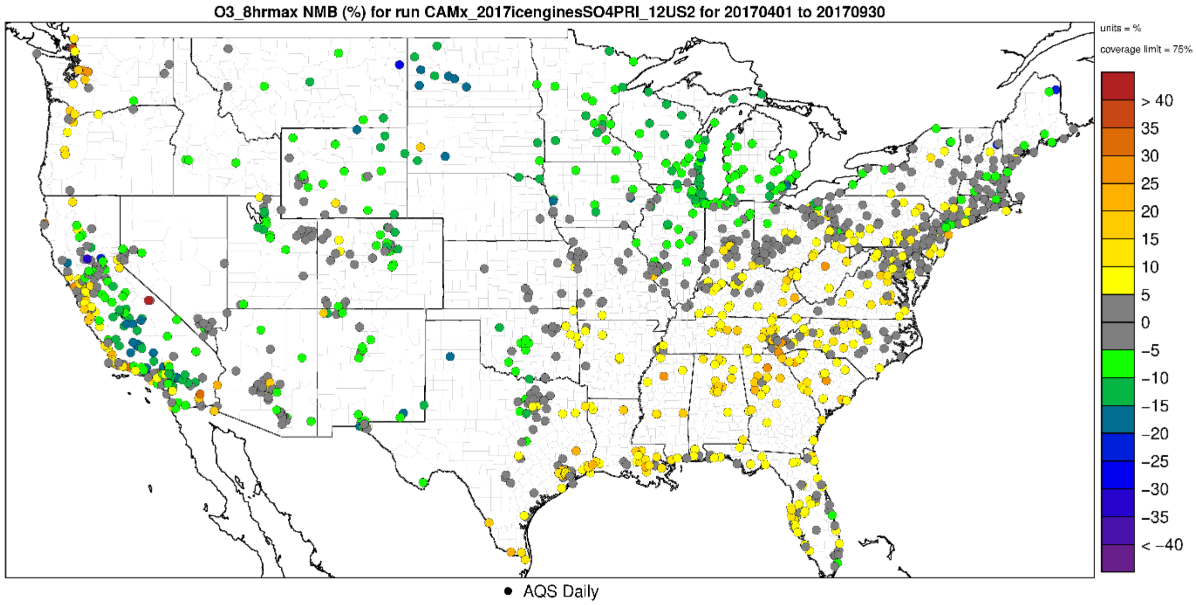

Figure C-3 Map of 2017 CAMx MDA8 Normalized Mean Bias (%) for April–September at all U.S. monitoring sites in the model domain

C.1.2 Source Apportionment Modeling

The contribution of specific emissions sources to ozone in the 2017 modeled case were tracked using a tool called "source apportionment." In general, source apportionment modeling quantifies the air quality concentrations formed from individual, user-defined groups of emissions sources or "tags." These source tags are tracked through the transport, dispersion, chemical transformation, and deposition processes within the model to obtain hourly gridded contributions from the emissions in each individual tag to hourly modeled concentrations of ozone.

For this analysis ozone contributions were modeled using the Ozone Source Apportionment Technique (OSAT) tool. In this modeling, VOC emissions from oil and natural gas operations were tagged separately for three regions of the U.S. regions. The model-produced gridded hourly ozone contributions from emissions from each of the source tags which we aggregated up to an ozone metric relevant to recent health studies (i.e., the April-September average of the MDA8 ozone concentration). The April-September average of the MDA8 ozone contributions from each regional oil and natural gas tag were summed to produce a spatial field representing national oil and natural gas VOC contributions to ozone across the United States (Figure C-4).

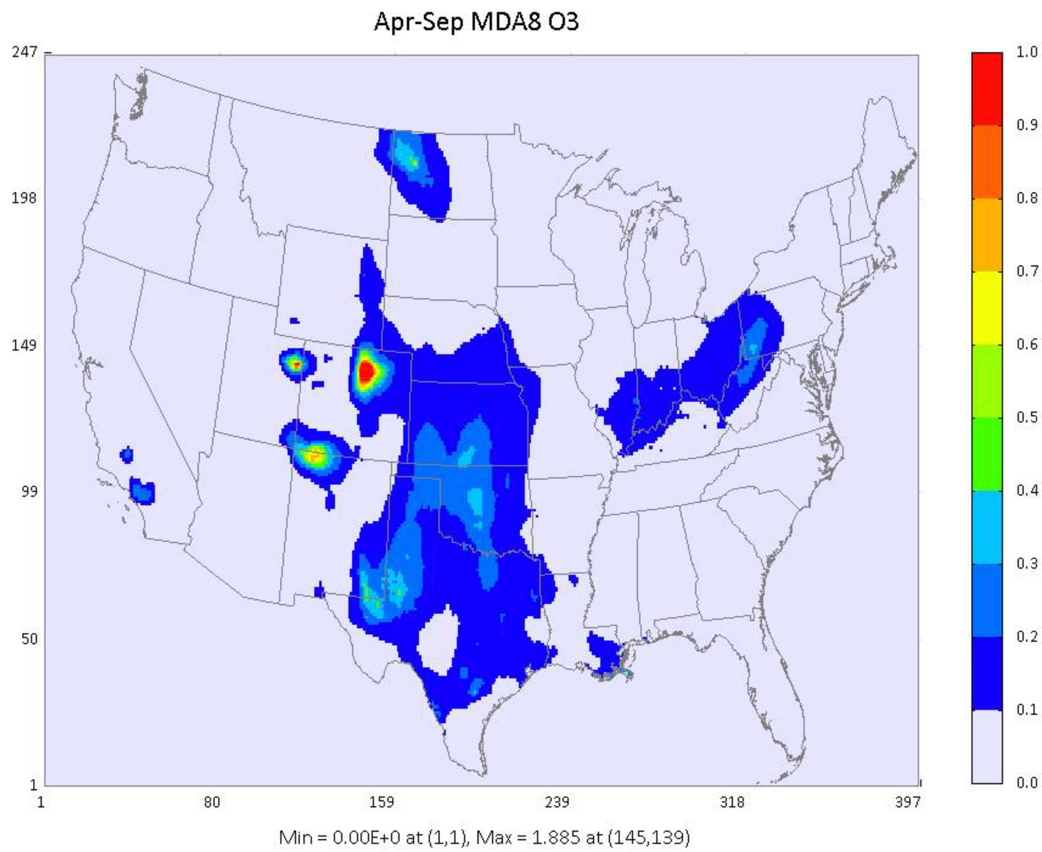

Figure C-4 Contributions of 2017 Oil and Natural Gas VOC Emissions across the Contiguous U.S. to the April-September Average of MDA8 Ozone.

C.2 Applying Modeling Outputs to Quantify a National VOC-Ozone Benefit Per-Ton Value

Following an approach detailed in the RIA and TSD for the Revised Cross-State Update, we estimated the number and value of ozone-attributable premature deaths and illnesses for the purposes of calculating a national ozone VOC benefit per-ton value for the proposed policy scenario (U.S. EPA, 2021f, 2021g).

The EPA historically has used evidence reported in the Integrated Science Assessment (ISA) for the most recent NAAQS review to inform its approach for quantifying air pollution-attributable health, welfare, and environmental impacts associated with that pollutant. The ISA synthesizes the toxicological, clinical and epidemiological evidence to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either short-term (hours to less than one month) or long-term (one month to years) 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. We estimate the incidence of air pollution-attributable premature deaths and illnesses using methods reflecting evidence reported in the 2020 Ozone ISA (U.S. EPA, 2020a) and accounting for recommendations from the Science Advisory Board. When updating each health endpoint the EPA considered: (1) the extent to which there exists a causal relationship between that pollutant and the adverse effect; (2) whether suitable epidemiologic studies exist to support quantifying health impacts; (3) and whether robust economic approaches are available for estimating the value of the impact of reducing human exposure to the pollutant. Detailed descriptions of these updates are available in the TSD for the Final Revised Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Update titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* (U.S. EPA, 2021h).

In brief, we used the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) to quantify estimated counts of premature deaths and illnesses attributable to summer season average ozone concentrations using the modeled surface described above (Section C.1.2). We calculate effects using a health impact function, which combines information regarding the: concentration-response relationship between air quality changes and the risk of a given adverse outcome; population exposed to the air quality change; baseline rate of death or disease in that population; and air pollution concentration to which the population is exposed. These quantified health impacts were then used to estimate the economic value of these ozone-attributable effects as described below. For this supplemental proposal, we quantified counts of premature deaths and illnesses by multiplying an incidence per ton against an updated estimate of emissions described in Section 2.3. Modeled air quality changes were not available.

We performed BenMAP-CE analyses for each year between 2023 and 2035, using the single model surface described above, but accounting for the change in population size, baseline death rates and income growth in each future year. We next divided the sum of the monetized ozone benefits in each year the April-September VOC emissions associated with the oil and natural gas source apportionment tags in the 2017 CAMx modeling to determine a benefit per ton value for each year from 2023–2035. Emissions totals for the oil and natural gas sector used in the contribution modeling are reported in U.S. EPA (2021a). Finally, the benefit per ton values were multiplied by the expected national VOC emissions changes in each year, as reported in Section 2.3. Since values reported in Section 2 were annual totals, we assume the emissions changes are distributed evenly across months of the year and divide emissions changes by two to estimate the April-September VOC changes expected from this supplemental proposed rule.

C.3 Uncertainties and Limitations of Air Quality Methodology

The approach applied in this screening analysis is consistent with how air quality impacts have been estimated in past regulatory actions (U.S. EPA, 2019b, 2021f). However, in this section we acknowledge and discuss several limitations.

First, the 2017 modeled ozone concentrations are subject to uncertainty. While all models have some level of inherent uncertainty in their formulation and inputs, evaluation of the model outputs against ambient measurements shows that ozone model performance is within the range of model performance reported from photochemical modeling studies in the literature (Emery et al., 2017; Simon et al., 2012) and is adequate for estimating ozone impacts of VOC emissions for the purpose of this rulemaking.

In any complex analysis using estimated parameters and inputs from a variety of models, there are likely to be many sources of uncertainty. This analysis is no exception. This analysis includes many data sources as inputs, 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 world (i.e., regulations, technology, and human behavior). Each of these inputs are uncertain and generate uncertainty in the benefits estimate. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits. Therefore, the estimates of annual benefits should be viewed as representative of the magnitude of benefits expected, rather than the actual benefits that would occur every year.

Because regulatory health impacts are distributed based on the degree to which housing and work locations overlap geographically with areas where atmospheric concentrations of pollutants change, it is difficult to fully know the distributional impacts of a rule. Air quality models provide some information on changes in air pollution concentrations induced by regulation, but it may be difficult to identify the characteristics of populations in those affected areas, as well as to perform high-resolution air quality modeling nationwide. Furthermore, the overall distribution of health benefits will depend on whether and how households engage in averting behaviors in response to changes in air quality, e.g., by moving or changing the amount of time spent outside (Sieg, Smith, Banzhaf, & Walsh, 2004).

Another limitation of the methodology is that it treats the response of ozone benefits to changes in emissions from the tagged sources as linear. For instance, the benefits associated with a 10 percent national change in oil and natural gas VOC emissions would be estimated to be twice as large as the benefits associated with a 5 percent change in nation oil and natural gas VOC emissions. The methodology therefore does not account for 1) any potential nonlinear responses of ozone atmospheric chemistry to emissions changes and 2) any departure from linearity that may occur in the estimated ozone-attributable health effects resulting from large changes in ozone exposures. We note that the emissions changes between scenarios are relatively small compared to 2017 emissions totals from all sources. Previous studies have shown that air pollutant concentrations generally respond linearly to small emissions changes of up to 30 percent (Cohan, Hakami, Hu, & Russell, 2005; Cohan & Napelenok, 2011; Dunker, Yarwood, Ortmann, & Wilson, 2002; Koo, Dunker, & Yarwood, 2007; Napelenok, Cohan, Hu, & Russell, 2006; Zavala, Lei, Molina, & Molina, 2009) and that linear scaling from source apportionment can do a reasonable job of representing impacts of 100 percent of emissions from individual sources (Baker & Kelly, 2014). Additionally, past studies have shown that ozone responds more linearly to changes in VOC emissions than changes in NO_X emissions (Hakami, Odman, & Russell, 2003; Hakami, Odman, & Russell, 2004). Therefore, it is reasonable to expect that the ozone benefits from expected VOC emissions changes from this proposed rule can be adequately represented using this this linear assumption.

A final limitation is that the source apportionment ozone contributions reflect the spatial and temporal distribution of the emissions from each source tag in the 2017 modeled case. The representation of the spatial patterns of ozone contributions are important because benefits calculations depend on the spatial patterns of ozone changes in relationship to spatial distribution of population and health incidence values. While we accounted for changes the size of the population, baseline rates of death and income, we assume the spatial pattern of oil and natural gas VOC contributions to ozone remain constant at 2017 levels. Thus, the current methodology does not allow us to represent any expected changes in the spatial patterns of ozone that could result from changes in oil and natural gas emissions patterns in future years or from spatially heterogeneous emissions changes resulting from this supplemental proposed rule. For instance, the method does not account for the possibility that new sources would change the spatial distribution of oil and natural gas VOC emissions. In addition, the method does not account for any changes in spatial patterns of ozone that would result from spatially varying emissions change which could result from differing impacts of this proposed rule in locations with existing state regulations. For instance, in Section 2 we describe the impact of existing regulations in Colorado and California. Due to the stringency of current on-the-books oil and natural gas regulations in these and other states, we do not expect large impacts from this rule of VOC emissions in those states. We note specifically that Figure 4-2 depicts that oil and natural gas VOC contributions to ozone are large in Colorado compared to other parts of the contiguous US. In addition, Figure 4-2 shows that there are some modeled oil and natural gas VOC contributions to ozone in densely populated southern California. Since VOC emissions impacts from this rule are calculated at a national level, at this time we do not have more refined information which could be used to spatially vary the response of ozone impacts to proposed VOC emissions changes. We also note that while we have identified existing state regulations in California and Colorado, we have not characterized the impacts of state regulations from other states on VOC emissions impacts or associated ozone benefits nor have we characterized how spatially heterogeneous emissions changes due to other factors would impact the quantified benefits.

Table C-2 Estimated Avoided Ozone-Related Premature Respiratory Mortality and Illnesses for the Proposed NSPS OOOOb and EG OOOOc Option in 2026[a,b]

Avoided premature respiratory mortality		Proposed NSPS OOOOb and EG OOOOc
Long-term exposure	Turner et al. (2016)	73
Short-term exposure	Katsouyanni et al. (2009)[b] and Zanobetti et al. (2008)[c,d] pooled	3.3
Avoided respiratory morbidity effects		
Long-term exposure	Asthma onset[d]	620
	Allergic rhinitis symptoms[f,e]	3,500
Short-term exposure	Hospital admissions—respiratory[b]	8.4
	ED visits—respiratory[g]	190
	Asthma symptoms[g]	120,000
	Minor restricted-activity days[b]	53,000
	School absence days[c,h]	40,000

[a] Values rounded to two significant figures.
[b] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

Table C-3 Benefit Per Ton Estimates of Ozone-Attributable Premature Mortality and Illnesses for the Proposal in 2026

	Benefit Per Ton of Reducing VOC from the Oil and Natural Gas Sector
Short-term mortality and morbidity health effects (discounted at 3%)	$230
Short-term mortality and morbidity health effects (discounted at 7%)	$210
Long-term mortality and morbidity health effects (discounted at 3%)	$1,800
Long-term mortality and morbidity health effects (discounted at 7%)	$1,600

Table C-4 Estimated Discounted Economic Value of Ozone-Attributable Premature Mortality and Illnesses under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035 (million 2019$)[a,d]

	Proposed NSPS OOOOb and EG OOOOc Option	
Year	**3% Discount Rate**	**7% Discount Rate**
2023	$6.8[b] to $51[c]	$6.0[b] to $46[c]
2024	$10[b] to $78[c]	$9.1[b] to $70[c]
2025	$14[b] to $110[c]	$12[b] to $96[c]
2026	$110[b] to $830[c]	$95[b] to $750[c]
2027	$110[b] to $860[c]	$97[b] to $770[c]
2028	$110[b] to $870[c]	$99[b] to $780[c]
2029	$110[b] to $900[c]	$100[b] to $800[c]
2030	$120[b] to $930[c]	$100[b] to $830[c]
2031	$120[b] to $950[c]	$110[b] to $850[c]
2032	$120[b] to $980[c]	$110[b] to $880[c]
2033	$120[b] to $990[c]	$110[b] to $890[c]
2034	$120[b] to $1,000[c]	$110[b] to $910[c]

2035	\$130[b] to \$1,000[c]	\$110[b] to \$940[c]

[a] Values rounded to two significant figures.
[b] Includes ozone mortality estimated using the pooled Katsouyanni et al. (2009) and Zanobetti and Schwartz (2008) short-term risk estimates.
[c] Includes ozone mortality estimated using the Turner et al. (2016) long-term risk estimate.
[d] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

Table C-5 Stream of Human Health Benefits under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035: Monetized Benefits Quantified as Sum of Avoided Morbidity Health Effects and Avoided Long-term Ozone Mortality (discounted at 3 percent to 2021; million 2019\$)[a,b]

Year	Proposed NSPS OOOOb and EG OOOOc Option
2023	\$51
2024	\$78
2025	\$110
2026	\$830
2027	\$860
2028	\$870
2029	\$900
2030	\$930
2031	\$950
2032	\$980
2033	\$990
2034	\$1,000
2035	\$1,000
Present Value (PV)	**\$7,200**
Equivalent Annualized Value (EAV)	**\$680**

[a] Benefits calculation includes ozone-related morbidity effects and avoided ozone-attributable deaths quantified using the Turner et al. (2016) long-term risk estimate.
[b] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

Table C-6 Stream of Human Health Benefits under the Proposed NSPS OOOOb and EG OOOOc Option, 2023–2035: Monetized Benefits Quantified as Sum of Avoided Morbidity Health Effects and Avoided Long-term Ozone Mortality (discounted at 7 percent to 2021; million 2019$)[a,b]

Year	Proposed NSPS OOOOb and EG OOOOc
2023	$46
2024	$70
2025	$96
2026	$750
2027	$770
2028	$780
2029	$800
2030	$830
2031	$850
2032	$880
2033	$890
2034	$910
2035	$940
Present Value (PV)	**$4,600**
Equivalent Annualized Value (EAV)	**$550**

[a] 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).
[b] The EG OOOOc regulates emissions of methane. Additional benefits to the regulation result from associated reductions in VOC emissions.

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APPENDIX D FUGITIVE EMISSIONS ABATEMENT SIMULATION TOOLKIT (FEAST) MEMO

This appendix summarizes fugitive emission modeling that the EPA conducted using the Fugitive Emissions Abatement Simulation Toolkit (FEAST) version 3.1.[120] FEAST is a customizable, open-source modeling framework developed to evaluate the effectiveness of different methane leak detection and repair (LDAR) programs at oil and gas facilities. Model inputs include the number and type of emission source, a leak generation rate by emission source type, a distribution of leak rates when a leak is generated, and the probability of the selected leak detection method detecting a leak of a given size. Separate leak distributions were developed for typical fugitive components (valves, pumps, connectors), storage vessels, and "large-emitters." The EPA evaluated both component-level surveys, like those conducted using an optical gas imaging (OGI) camera, and site-level surveys such as satellite or aerial surveys for various sizes of facilities (model plants). Monte Carlo analyses were conducted using FEAST to assess different LDAR programs (survey type, frequency, and method detection level) with and without large-emitters included in the analysis.

The large-emitter distribution was developed to characterize emissions from component-level leaks using an assumed distribution of emissions and leak generation rate, ranging from very small to very large emissions, with the large emissions occuring less frequently. The large-emitter distribution is not directly related to the definition of "super-emitter" included in this proposal and the emissions reported for simulations including large-emitters cannot directly be used to assess the emissions or emission reductions related to the proposed super-emitter program. We found the modeled FEAST emissions are highly dependent on the assumed "leak generation rate" (i.e., frequency) of the large-emitters. The EPA selected a reasonable central tendency value for this parameter based on aerial studies conducted within the Permian basin and conducted limited sensitivity analyses around this input parameter. The sensitivity analysis results suggest that there are large uncertainties in the emissions contribution by large-emitters based on the frequency at which large emission events occur. Available data suggest that the assumed frequency of large emission events may vary significantly across different production basins, so any national-level impact estimates that relied on extending the large-emitter emission

[120] https://github.com/FEAST-SEDLab/FEAST_PtE/tree/FEAST_3.1

estimates presented in this memorandum to basins beyond the Permian basin would be subject to significant uncertainty.

RTI INTERNATIONAL | **Memorandum**

FROM: Jeff Coburn and Ricky Strott, RTI International

TO: Karen Marsh, EPA/OAQPS

FOR: EPA Docket No. EPA-HQ-OAR-2020-0317

DATE: July 27, 2022

SUBJECT: Modeling Fugitive Emissions from Production Sites Using FEAST

1. Purpose

This memorandum documents emission estimates for fugitive emission components at oil and gas production sites using Fugitive Emissions Abatement Simulation Toolkit (FEAST). The first objective of the modeling effort was to identify cost effective monitoring options when using ground-based OGI. The second objective was to identify site-wide survey methods that were equivalent to ground-based OGI.

2. Background

The Environmental Protection Agency (EPA) has used leak detection and repair (LDAR) programs as a means to reduce emissions from leaking fugitive emission components for a wide range of industry sectors. These LDAR programs traditionally used Method 21 of Appendix A-7 of 40 CFR part 60 (EPA Method 21), which uses a volatile organic monitor and a small pump to draw air through sampling probe to the monitor. EPA Method 21 requires operators to slowly traverse likely leak points, like a valve stem or flange, in attempts to identify areas of high hydrocarbon concentration, indicating a leak. EPA Method 21 is labor and time intensive because it requires the operator to physically locate each fugitive emission components and to on an individual basis, traversing each component slowly enough to allow the monitor to respond to a leak.

In 2008, EPA promulgated the alternative work practice, which allows owners and operators to use optical gas imaging (OGI) cameras to see a hydrocarbon leak using a sophisticated hand-held camera. These devices allow operators to scan for leaks more quickly than when using EPA Method 21. OGI may not be able to detect small leaks that EPA Method 21 can detect, but by deploying OGI more often, OGI monitoring can achieve emission reductions similar to EPA Method 21-based LDAR programs.[1] EPA first promulgated OGI monitoring as the fugitive emissions detection method for fugitive emission components in the

[1] Although, OGI monitoring can achieve the same emission reductions as EPA Method 21-based programs in some cases, this may not always be true. For example, OGI cameras may not be able to image the compounds contained in some gaseous emissions, in which case, an OGI-based program could not be equivalent to an EPA Method 21-based program. It is necessary to evaluate the specific EPA Method 21-based program to determine whether equivalency with an OGI-based program is possible.

new source performance standards (NSPS) for oil and gas sites in 2016 (81 FR 35824, June 3, 2016; 40 CFR part 60, subpart OOOOa).

Technology continues to advance and there are a wide variety of different technologies for fugitive emissions monitoring that are either available now or shortly in the future. These include a network of continuous monitoring systems, tower-mounted laser-based monitoring systems, automobile-mounted monitoring systems (or simply "mobile" systems), aircraft-mounted monitoring systems (or simply "aerial" systems), drone-mounted systems, or satellite-based monitoring systems. However, the current regulations require individual facilities to request an alternative means of emissions limitation (AMEL) to use these alternative technologies. The EPA is developing a streamlined process for use of these technologies by specifying attributes (i.e., monitoring frequency and detection sensitivity) for these site-wide monitoring techniques that are expected to achieve the same emission reductions as the ground-based OGI monitoring that was determined to be the best system of emission reduction (BSER). The FEAST model was specifically developed to allow users to model the emission reductions achieved when deploying various site-wide or ground-based surveys.

3. FEAST Model Setup

3.1 FEAST Overview

FEAST is an open-source modeling framework developed "…to evaluate the effectiveness of methane leak detection and repair (LDAR) programs at oil and gas facilities."[2] FEAST was initially developed at the Environmental Assessment and Optimization group at Stanford University by Chandler E. Kemp, Arvind P. Ravikumar, and Adam R. Brandt and released in 2016.[3] The FEAST model is currently on the fourth version: FEAST 3.1[4] (referred to only as FEAST for the purpose of this memo) and is based in Python 3. FEAST provides a stochastic model of emissions at the component level occurring as the result of leaks (that can be identified and repaired through the LDAR program) and vents (that may be "detected" by some LDAR programs but are not subject to repair) in a natural gas field.

FEAST is highly customizable. The time step and duration of the simulation can be set by the user. Different components can be defined with different leak production (generation) rates and emission rate distributions for the leaks generated. Sites can be defined as a collection of different components and a gas field can be defined as a collection of sites. FEAST supports the following LDAR technologies and can model hybrid LDAR programs:

- Optical gas imaging (OGI) camera
- Aerial surveys (both equipment- and site-level surveys)
- Drone surveys
- Continuous monitoring systems

[2] https://www.arvindravikumar.com/feast
[3] C.Kemp et al. Environ. Sci. Tech. 50 4546. http://dx.doi.org/10.1021/acs.est.5b06068
[4] https://github.com/FEAST-SEDLab/FEAST_PtE/tree/FEAST_3.1

The LDAR program effects are simulated based on probability of detection (PoD) curves (or surfaces) for each monitoring method, which indicate the probability that a leak of a given size will be detected within a given survey (or time period for continuous monitoring technologies), and survey times (frequencies) are accounted for as finite time periods. Based on parameters of the repair process, emission mitigation is quantified for leaking emissions which are repaired, resulting in a lower emission profile relative to the baseline scenario.

3.2 FEAST General Modeling Approach

We conducted all modeling runs using a 1-day time step. We ran the model for 5 years and compared the emissions in the fifth year. This modeling approach was used to allow for the buildup of small leaks that different monitoring methods may not be able to detect. We varied the leak generation rates for conventional components from 0.5 to 2 percent per year. We assessed different "auto-repair" rates, which is the rate at which leaks fix themselves or are repaired in the absence of an LDAR program. We decided to set the auto-repair rate to zero because the auto-repair applied to all leaks, regardless of size. That is, when using the auto-repair approach, the operator is assumed to find and fix very small leaks at the same rate as larger leaks. This limits the buildup of small, very difficult to detect leaks when using an auto-repair rate. Because we do not believe these small leaks would be repaired as often as larger leaks (in the absence of a regulatory program), we used a "baseline monitoring program" to simulate facilities occasionally identifying larger leak sources using audio, visual, or olfactory (AVO) methods and repairing those larger leaks – those that would result in cost-savings to repair.

Because we were interested in identifying appropriate monitoring frequencies for different types of facilities, we always modeled only one site type at a time. We modelled the field as 20 identical sites of the type we were evaluating. The model output provides emissions and repair data for each site. We compiled the average site emissions and the number of repairs made per site in the 5th year for each model run to use in our costing analysis.[5] Each model run consisted of emissions analysis for the field, which was defined as 20 model plant sites. We used a Monte Carlo approach, conducting analysis of the field emissions under a different set of leak generated for each Monte Carlo iteration.

3.3 Emission Leak Distributions

FEAST includes a default leak data set for production facilities. The study data included in the FEAST default data set are collected from the following measurement studies.

- *Measurements of Methane Emissions at Natural Gas Production Sites in the United States, Supporting Information* (Allen *et al.*, 2013). For this study, 150 natural gas production sites were surveyed, and leaks were detected at 97 sites. Equipment leaks were assessed at compressors, well heads, and equipment in four producing regions of the United States: Appalachia, Gulf Coast, Mid-Continent, and Rocky Mountains. Sites were screened with an infrared camera to identify leaks, and all observed leaks

[5] FEAST has cost estimating procedures, but rather than attempt to revise the cost input data files to match the EPA's historic cost estimates for conducting OGI, it was easier to estimate monitoring costs outside of FEAST using the number of repairs made in the fifth year and conduct the cost analysis outside of FEAST.

were measured with a Bacharach high-flow sampler.[6] Emissions data are available from the web site of the Center for Energy and Environmental Resources at the University of Texas, Austin; the data include approximately 278 measurements of whole gas and methane emissions from leaks at production sites.[7]

- *City of Fort Worth Natural Gas Air Quality Study* (ERG and Sage, 2011). This study measured fugitive gas emissions from equipment in the Fort Worth Basin associated with the Barnett Shale including: 375 well pads, eight compressor stations, one gas processing plant, and one produced water treatment facility. Leak screening and measurement was performed using OGI and a high flow sampler for a total of 91 methane measurements at gathering and boosting facilities and 1,200 measurements at production facilities. These data are listed as "ERG Camera 2011" in the default data set. EPA Method 21 and bagging techniques were also performed on selected sources. These data are listed separately from the OGI data as "ERG TVA 2011" in the default data set. All production facilities in the study are located in the Fort Worth Basin and are associated with gas production from the Barnett Shale.

- *Estimation of Methane Emissions from the California Natural Gas System* (Kuo et al., 2015). FEAST documentation reports this study as Kuo, 2011; expect the study was conducted in 2011, but not published until 2015. This study measured fugitive emissions from 25 facilities in California representing facilities across the natural gas industry; 12 of the facilities were in the production and processing sector. FEAST documentation notes that only the production well equipment were included in the FEAST data set. EPA Method 21 was used to identify leaks; Bacharach Hi-Flow samplers were used to quantify the leaks. Study authors noted that the Bacharach Hi-Flow sampler could not accurately quantify some of the smaller leaks. They also noted that most sites visited were already conducting routine LDAR monitoring, which may lead to lower emission factors as compared to the 1995 GRI/EPA study.

- *Repeated leak detection and repair surveys reduce methane emissions over scale of years* (Ravikumar, *et al.*, 2020). This study included initial and follow-up measurements at 36 sites in Alberta, Canada: 30 well pads and 6 processing plants. A FLIR OGI camera was used to identify leaks; Bacharach Hi-Flow samplers were used to quantify the leaks. Study author noted that tank leaks were not measured due to safety concerns. Emission factors were developed for venting tanks from other study data; we used only measurement data from Ravikumar, so tank emission estimates from this study were not used. The study authors noted that equipment leak emissions were not well correlated with production, such that low production wells have similar emissions as high production wells.

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[6] The study authors noted in the Supporting Information that the threshold for detecting a leak with the infrared camera used by the study team was 30 grams per hour (g/hr) (0.026 standard cubic feet per minute (scf/min)), compliant with the approved alternative work practices in 40 CFR 60.18. In practice, the threshold for leak detection depends upon operator experience and skill in interpretation of the visual images, as well as site-specific parameters such as the visual background for the leak image.

[7] See Project Data sets for Allen (2013), available for download from Center for Energy and Environmental Resources, University of Texas, Austin. http://dept.ceer.utexas.edu/methane/study/datasets1.cfm.

- *Comparison of methane emission estimates from multiple measurement techniques at natural gas production pads (Bell, et al., 2017)*. This study estimated methane emissions at 268 gas production facilities in the Fayetteville shale gas play (in Arkansas) using onsite measurements (261 facilities) and two downwind methods – the dual tracer flux ratio method (Tracer Facility Estimate – TFE, 17 facilities) and the EPA Other Test Method 33a (OTM33A Facility Estimate – OFE, 50 facilities). Emission sources were first identified during a comprehensive site survey using a combination of optical gas imaging and handheld laser methane detection. Identified leaks were quantified using a high-flow samplers, with care to limit issues identified by Howard, et al., 2015. Only the component leak data were used.

The default FEAST data set included all measurement data from these studies, which may include measurements of pneumatic devices and tank thief hatch releases. While pneumatic devices may malfunction, these are not "leaks." Continuous bleed pneumatic devices emit continuously, so the "leak generation rate for these devices should be 100%. Intermittent bleed devices only bleed when they are actuating. Some intermittent bleed devices used for process control may actuate every few minutes; other intermittent bleed devices are used to actuate isolation valves and may actuate only a few times a year. However, these are not leaks and it is incorrect to characterize "leaks" based on pneumatic device bleed rates. Pneumatic device emissions may be included as vented emissions (non-repairable), but they must be modeled differently than "leaks." Consequently, we separated the data so that equipment component data [i.e., valves, connectors, flanges, pumps, open-ended lines (OELs), and pressure relieve valves (PRV)] were in one file and tank "leak" emissions were in another file. We also compiled other measurement data in the default FEAST input file (for pneumatics or liquids unloading venting), but these were not used.

In addition to the filtered study data from contained in the default FEAST leak data set, we also augmented the FEAST leak data set with data from two other studies that were recently reviewed. These studies are:

- *Equipment leak detection and quantification at 67 oil and gas sites in the Western United States* (Pacsi, *et al.*, 2019). This study included 67 production and gathering and boosting oil and gas sites in the Permian, Anadarko, Gulf Coast and San Juan basins. Equipment leaks were screened on all major equipment using OGI and EPA's Method 21. Emissions from leaks were quantified using a high-flow sampler. Complete equipment leak component inventories were also performed at each site.

- *Methane Emissions from Gathering Compressor Stations in the U.S. (Zimmerle, et al., 2020a)*. This study included 180 gathering stations for which information was collected on equipment counts and types. Component level equipment leak screening was also performed using OGI, and emissions were quantified using a high-flow sampler. We note that the Zimmerle *et al.*, 2020a paper nor its supporting information provided direct results of the equipment component activity data, however, these results were provided in Supporting Volume 3 of the Department of Energy (DOE) report (Zimmerle *et al.*, 2019).

Data from these studies were similarly parsed between equipment component leak data and tank leak data.

Note that, because almost all of these studies largely relied on high-flow samplers, most of the leak data are limited to the minimum and maximum detection limits of the high-flow sampler, which is about 0.01 to 8 standard cubic feet per minute (scfm) or about 0.01 to 9 kg/hr. Aerial studies have indicated site wide emissions are often much higher and some individual sources may also be much higher than these. In order to account for large emission events, data from the following aerial study were used to develop a distribution for high emitting sources.

- *Intermittency of Large Methane Emitters in the Permian Basin, (Cusworth, et al., 2021)*. This study conducted aerial methane leak detection covering 55,000 km^2 area within the Permian basin. They used two different airborne platforms: a "next-generation" Airborne Visible/Infrared Imaging Spectrometer (AVIRIS-NG) and the Global Airborne Observatory (GAO). The GAO uses the same detection method (ARVIS-NG) but is also equipped with a high-resolution digital camera. Multiple flights were conducted of the study area between September and November 2019, to better understand the intermittency of large emitters. The study identified 3,067 unique plumes from 1,756 distinct sources over the course of the campaign. We used these individual plume data, which ranged in size from 15 kg/hr to 16,800 kg/hr, as the base of the large-emitter data set.

Because the Cusworth, et al, (2021) aerial methods had an apparent lower detection limit of 15 kg/hr during optimal conditions, we assumed that there were likely more large emission sources in the 5 to 50 kg/hr range that may not have been identified during the aerial survey due to lower detection limits of the aerial method used. Nonetheless, emissions in the 5 to 50 kg/hr are still large compared to the equipment component and tank leak data. Therefore, we augmented the Cusworth data with additional data in this range using assumed log-normal leak distribution.

To compare and contrast the study data, the input data file used for each study, which contains leak emissions data in units of g/sec, were evaluated. While not all of the different study data were log-normally distributed (often due to detection limit issues with the measurement methods used), we used natural log transform of the data to more easily compare and contrast the data. We present the data for equipment components first, then storage tank leaks, then "large-emitters."

3.3.1 Equipment Component Leaks

The box and whisker plot for each study in the equipment component leak data set are provided in **Exhibit 1**. Looking at the median values, the ERG Camera 2011 measurements contain the highest average emissions, while ERG TVA 2011 has the lowest. Most of the different study data using OGI as the primary detection limit have similar range of emissions data; these include: Allen 2013; Ravikumar 2020; Bell 2017; and Zimmerle 2019. Kuo 2012 (published 2015) has the highest emissions of the Method 21 studies; Pacsi 2019, which used a mix of Method 21 and OGI has a low leak distribution similar to the ERG TVA study. The ERG Camera 2011 is also the study with the second highest number of data points (751 records, second to the Zimmerle 2019) study, almost twice the number of records in the Ravikumar 2019 or Allen 2011 studies and 7 times the number of records in Kuo 2012 and Bell 2017, so the model is more likely to pick values from the ERG Camera 2011 study data than these other studies. Nonetheless, we specifically wanted to include EPA Method 21 identified leaks in this analysis to account for small leaks that OGI survey crews are not likely to detect.

It is evident that the Kuo 2012 (actually 2015 publication) and the Ravikumar 2020 data sets have lower detection limits with over a quarter of the data at the lowest measurement flow rate. A Q-Q plot of this data clearly shows that many studies use methods that identified leaks that were at or below the quantitation limit for the high-flow samplers (see **Exhibit 2**).

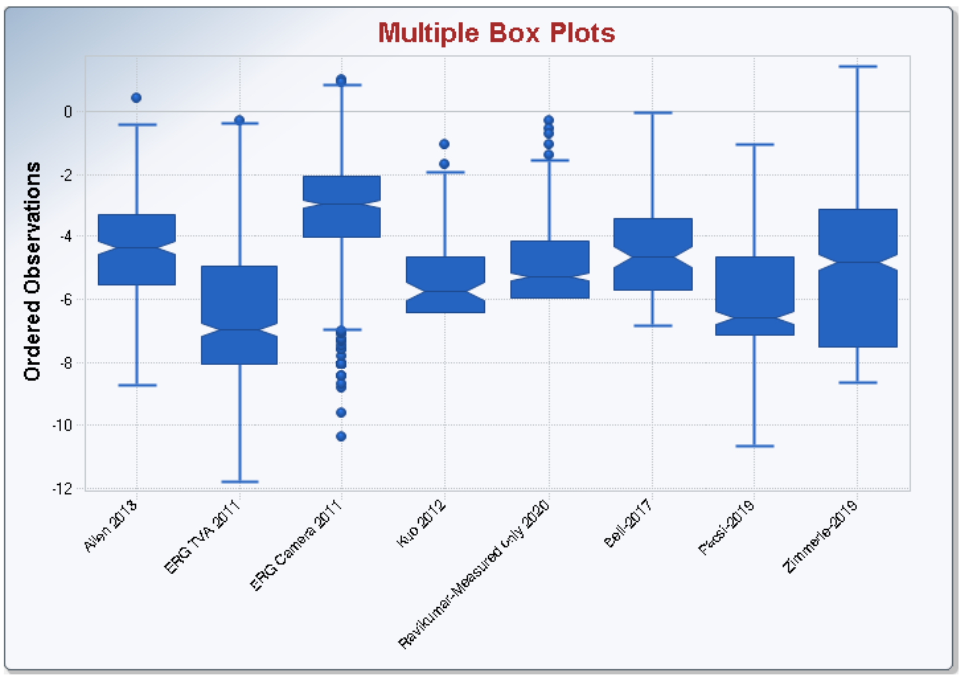

Exhibit 1. Box and whisker plot of Equipment Component leak data.

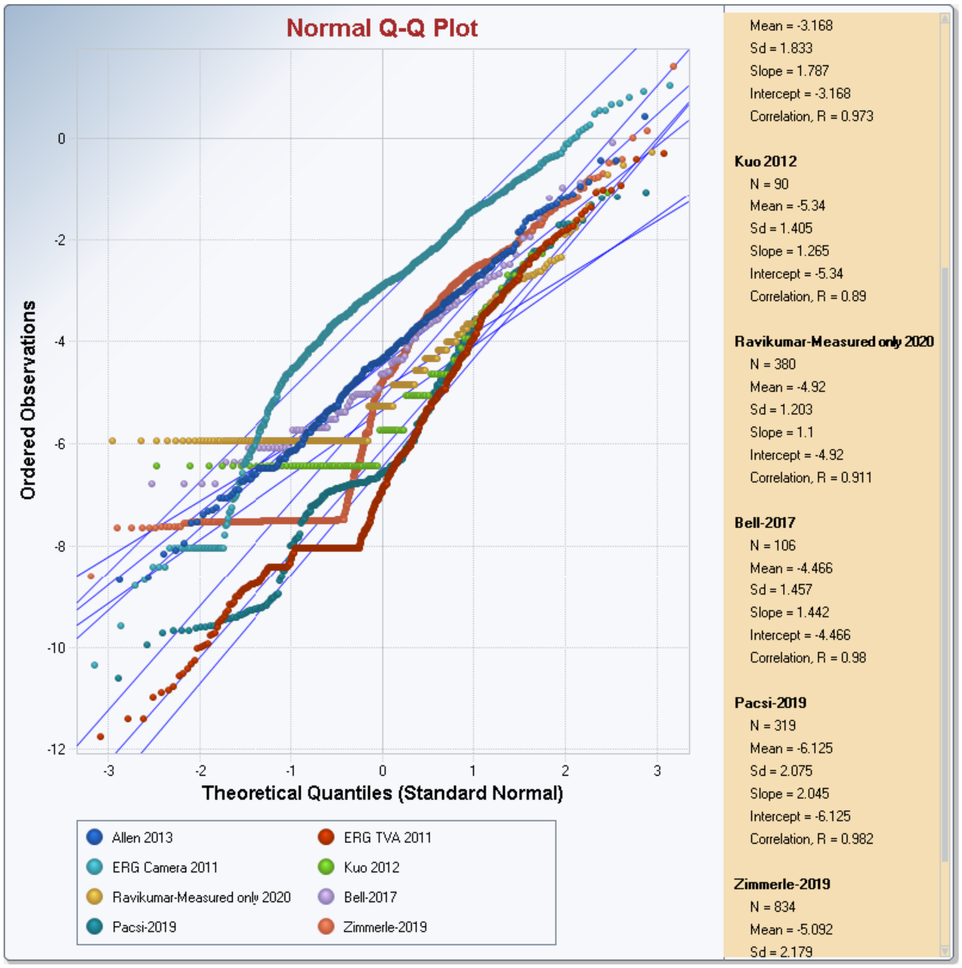

Exhibit 2. Q-Q plot of Equipment Component leak data.

Exhibit 3 provides the aggregate distribution of the combined data set (all studies) for the equipment components.

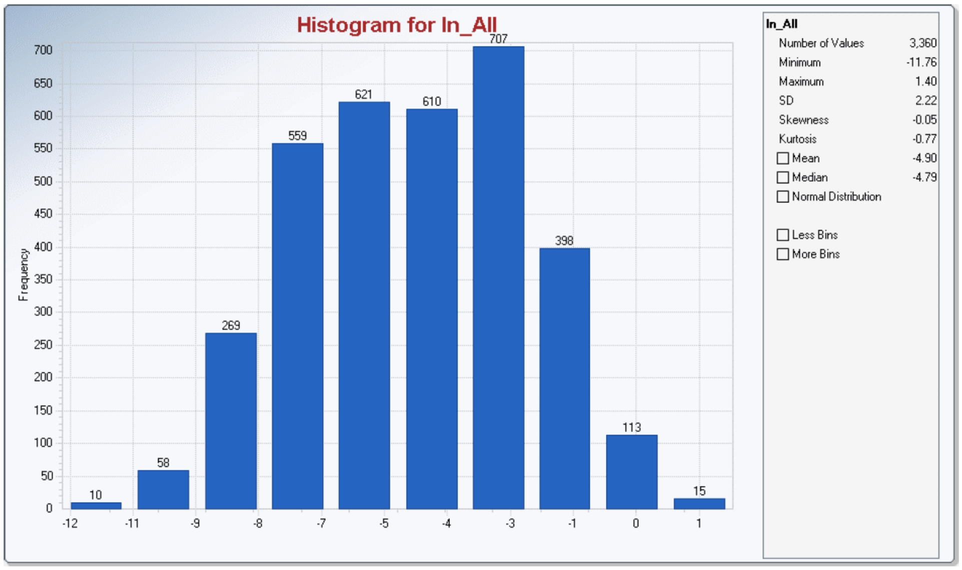

Exhibit 3. Histogram for the Equipment Leak data (natural logs of emissions in g/s).

3.3.2 Tank Leaks

The box and whisker plot for each study in the tank leak data set are provided in **Exhibit 3**. Again, the ERG Camera 2011 measurements contain the highest median emissions, the ERG TVA 2011 has the lowest, and the other study data have similar range of emissions in between these data. For the tank leaks data, the ERG Camera 2011 study has the highest number of data points (184 records), which is a factor of 2 or more times the number of records included in other studies. Again, this means that FEAST is more likely to pick values from the ERG Camera 2011 study data than from these other studies.

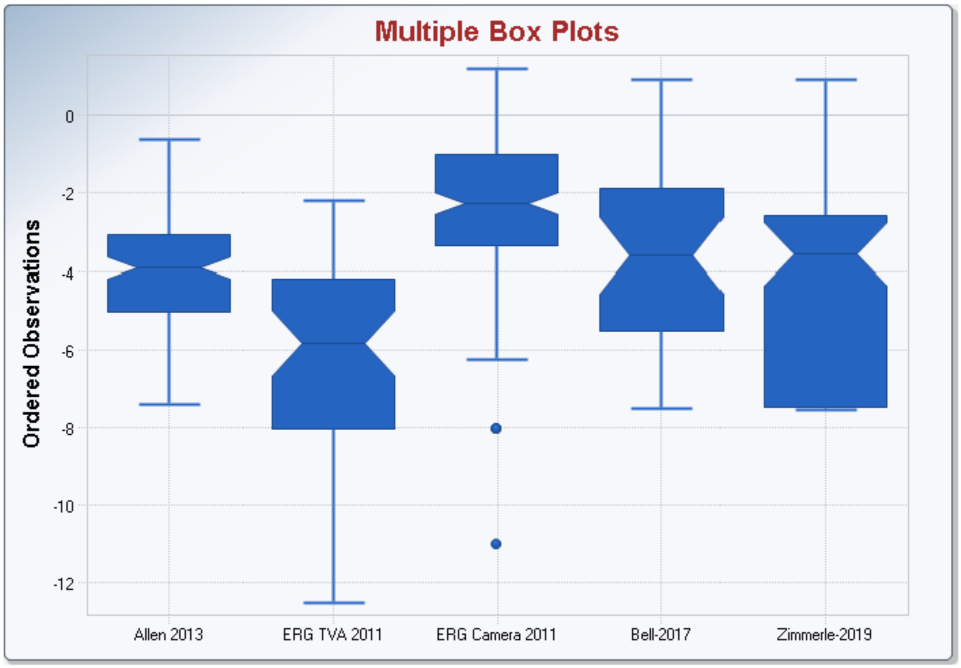

Exhibit 4. Box and whisker plot for the Tank leak data.

Exhibit 5 provides the aggregate distribution of the combined data set (all studies) for the tank leak data. The median emissions for tank leaks is around 0.05 g/s [ln(0.05) = -3], whereas the median emissions rate for equipment component leaks is around 0.007 g/s [ln(0.007) = -5]. Thus, the tank leaks are significantly larger than the equipment component leaks. However, a 0.05 g/s leak converts to 0.18 kg/hr, and the largest tank leak from any study used to develop the tank leak distribution is about 10 kg/hr, well below the lowest sitewide emissions seen in aerial surveys reported by Cusworth, et al., 2021. This is largely due to the limitations on the maximum pump (or sampling) rate of high flow samplers. High volume samplers typically have an upper quantitation limit of about 8 scfm, which translates into emissions of about 9 kg/hr assuming methane is the primary constituent.

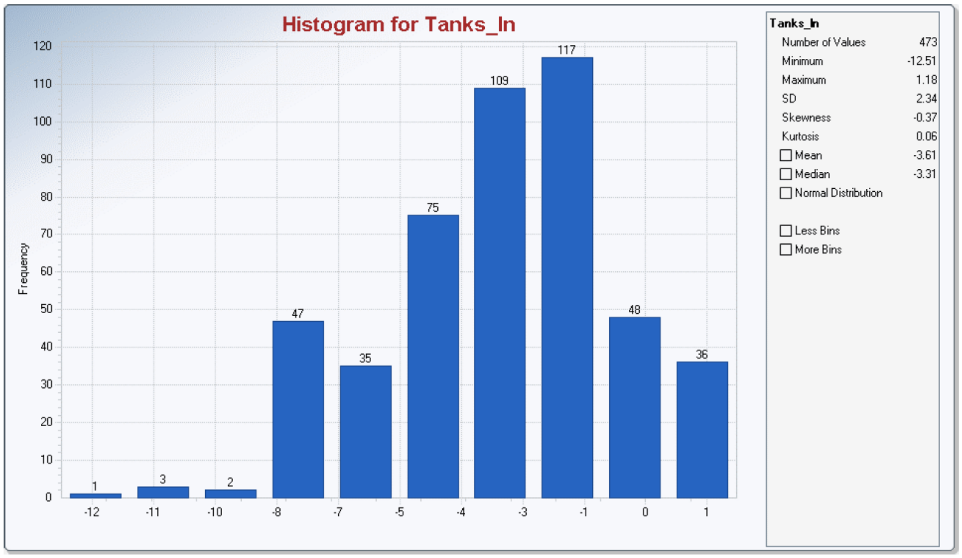

Exhibit 5. Histogram for the Tank Leak data (natural logs of emissions in g/s).

3.3.3 Large-Emitters

Exhibit 6 provides the distribution of site emissions from the Cusworth study. These emissions are much higher than the ground survey studies, largely due to the limits of detection of the different methods used. The smallest emission rate measured by Cusworth was 15 kg/hr and they only saw these emissions in 1 of 3 flyovers. While Cusworth focused on the intermittency of large-emitters, it is likely the intermittency seen at this lower level of detection is attributable to the varying meteorological conditions impacting the lower limit of detection. As such, rather than assume there are no or limited emissions between 10 kg/hr and 70 kg/hr based on Cusworth data, we surmised that the limited emissions in this range were more due to the limitations of emissions detection based on the sensitivity of the aerial methods considering the impacts of meteorology. Therefore, we augmented the Cusworth data to have a more even distribution of large-emitters between the maximum tank emissions and the median emissions of the Cusworth data.[8] **Exhibit 7** provides the aggregate distribution of the augmented data set for

[8] There were 3067 unique measurements from Cusworth, et al., 2021. We added 1,762 randomly generated values from a log-normal distribution using Excel equation =LOGNORM.INV(RAND(),2.6,0.6) and 1,233 values generated using Excel equation =LOGNORM.INV(RAND(),1.1,0.6). Note that the units of emissions in FEAST are g/sec. The first distribution yielded 90 percent of data between 18 and 125 kg/hr; the second distribution yielded 90 percent of data between 4 and 28 kg/hr.

large emission events. Note that the log normal value of 1 on this graph is equivalent to 10 kg/hr emission rate [e^1 = 2.7 g/sec = 9.8 kg/hr].

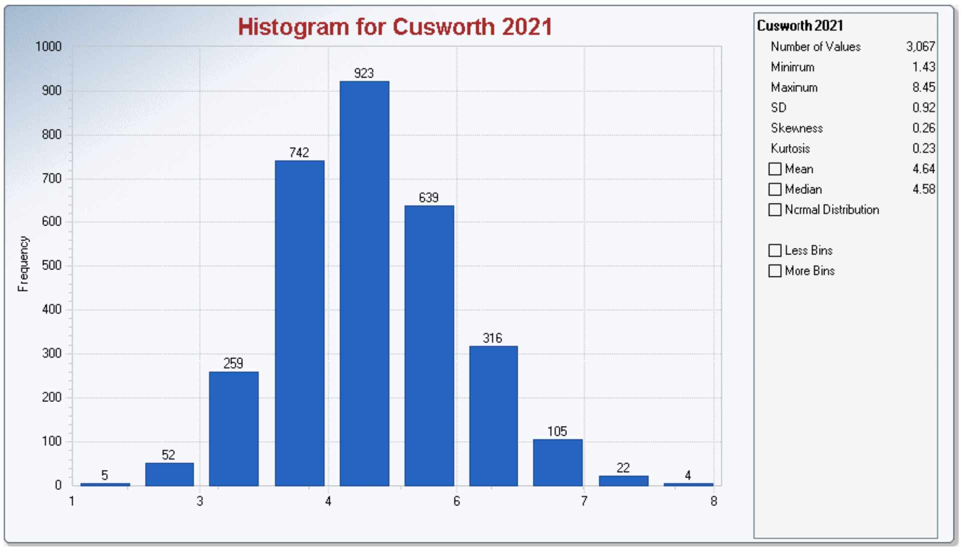

Exhibit 6. Histogram of data from Cusworth 2021.

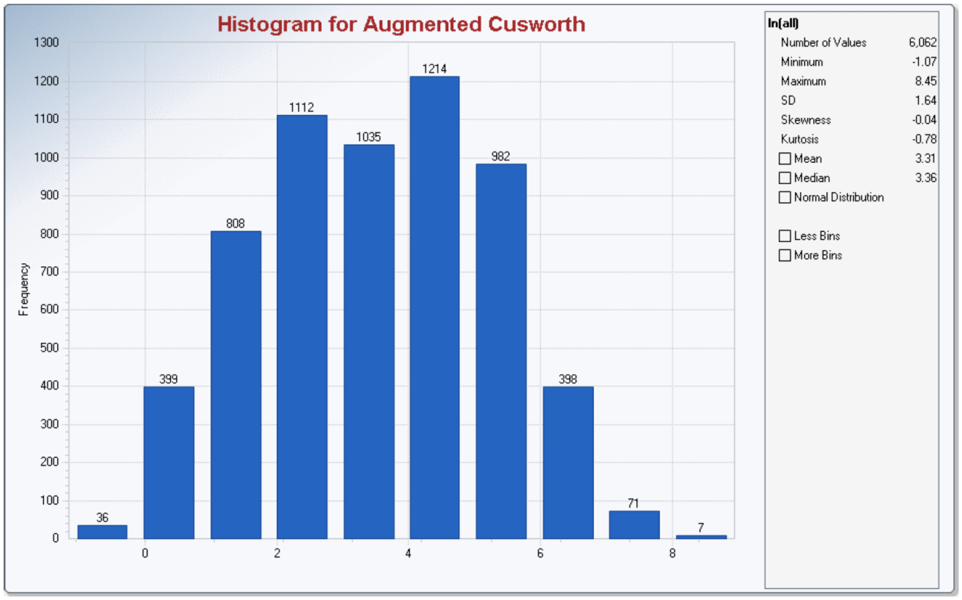

Exhibit 7. Histogram for the augmented "large-emitter" distribution.

3.4 Model Production Sites

In this evaluation, we considered four different model plants, based on the size and complexity of different production sites. **Table 1** summarizes the model production sites used in the FEAST modeling runs. The number of "sources" listed in Table 1 indicate the maximum number of potential leaking emission sources for a given leak distribution at the site.
While a large-emitter may be a very large leak from an equipment component or tank or another source (such as unlit flare or cracked pipe), we assign a value of 1 or 2 to large-emitters so the facility can have at most 1 or 2 large leaks pulled from the large-emitter leak distribution.

Table 1. Model Production Sites.

Model Site Name	Description	Number of Fugitive Equipment Components	Number of Tanks	Number of Large-Emitters
Model Plant 1	Single wellhead only	112	0	1
Model Plant 2	Dual wellheads only	220	0	1
Model Plant 3	Typical production site; uncontrolled tanks	612	0	2
Model Plant 4	Typical production site; controlled tanks	612	4	2

Model Plant 3 contains tanks, but as they are uncontrolled, the emissions from these tanks are allowed to vent to the atmosphere. Controlled tanks in Model Plant 4 must be vented through a closed vent system to a control device. Here, an open thief hatch or leak in the closed vent system could require action to repair the leak.

All FEAST model runs were performed with 20 sites of the model plant being evaluated within the field. The average emissions per site were determined for each simulation run of 20 sites.

3.5 Leak Detection Settings

For all survey types, we defined the leak detection curves by defining 0%, 25%, 50%, 75%, and 100% detection values. The 100 percent detection value for OGI was set based on the regulatory requirement. In the proposed NSPS OOOOb, this 100% detection limit was set at 60 g/hr. We recognize that even trained operators may not see all large leaks 100 percent of the time (Zimmerle, et al., 2020b), but we set the upper detection probability to 100 percent at 60 g/hr since the proposed NSPS OOOOb requires this sensitivity at a minimum.

For required OGI surveys as well as site-level survey methods, we assumed the 50% detection limit was a factor of 2 less than the 100% detection limit and the 0% detection limit was a factor of 4 less than the 100% detection limit. We set the 25% value as the midpoint between the 0 and 50% values and the 75% value was set as the midpoint between the 50 and 100% values. Thus, all detection curves for required surveys had the shape seen in **Exhibit 8**.

As noted previously, we set the auto-repair rate to zero and established a "baseline monitoring program" to simulate facilities occasionally identifying larger leak sources using AVO methods. We developed this baseline monitoring program initially before fully adopting the convention described above for the detection curves. For the baseline monitoring detection curve, we set the 100% detection limit at 0.034 g/s (122 g/hr), the 0% detection limit at a factor of 2 lower (61 g/hr) and used a straight line between these two points to determine the 25%, 50%, and 75% detection values. The survey frequency for this baseline survey was set at 650 days. This frequency was selected because it provided baseline emission estimates near those expected based on recent literature. We subsequently conducted an analysis specific to AVO and AVO monitoring frequencies and evaluated a broad range of probability detection curves for AVO methods. The probability detection curves assumptions and analysis conducted for AVO monitoring are described in Section 4.2 of this memorandum.

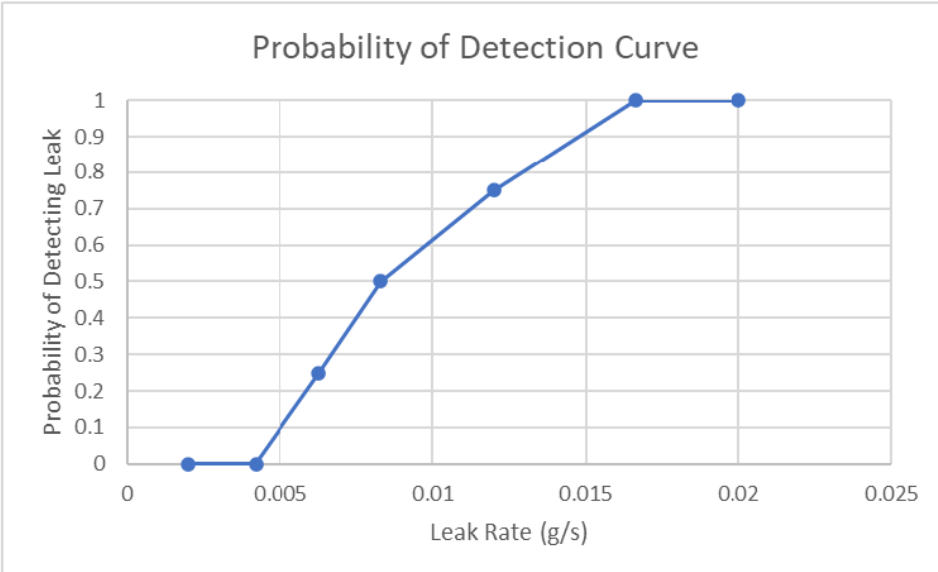

Exhibit 8. Detection probability curve for required ground-based OGI surveys.

4. FEAST Run Results for Fugitive Emission Components

Initial FEAST simulations were conducted to identify cost-effective, ground-based LDAR programs for the differently sized model plants using the emission distributions for fugitive emission components (including tank thief hatches) only. For these initial analyses, large emission events were not included. The following fugitive monitoring frequencies were evaluated:

- Annually
- Semi-annually
- Quarterly
- Bi-monthly
- Monthly

Initial runs evaluated both 15- and 30-day repair periods (delay between detection and repair). It is expected that a 30-day repair requirement would likely have an average of 15 days between detection and repair, with some repairs done quickly (on first attempt at repair) and some taking longer. However, because the repair period being considered was 30-days, all subsequent runs were conducted assuming 30-day "delay" between detection and repair.

4.1 Emission Estimate Results for OGI Monitoring Options

We evaluated site-wide emissions for each model plant based on a low, medium, and high leak generation rate as summarized in **Table 2**.

Table 2. Leak Generation Rate Scenarios

Emission Source	Leak Generation Rate (% of components per year)		
	Low	Medium	High
Equipment components	0.5%	1%	2%
Tanks	2.5%	5%	10%

The results of the FEAST simulations are summarized in **Tables 3 through 6** for Model Plants 1 through 4 for various monitoring frequencies using OGI required to be able to detect 60 g/hr leak fugitive emission components. The magnitude of emissions is significantly impacted by the assumed leak generation rate, with emissions increasing in direct proportion to the assumed leak generation rate.[9] Even so, the percent emission reductions achieved by OGI monitoring program was essentially identical regardless of the assumed leak generation rate or the model plant configuration. The effectiveness of the various monitoring frequencies in terms of percent emissions from the baseline are summarized in **Table 7**.

Table 3. Emission Simulations Results for Model Plant 1

Monitoring Program	Average Emissions (tons CH_4/year) per Site for Leak Generation Rate Levels		
	Low[1]	Medium[1]	High[1]
Baseline	1.27	2.97	4.83
Annual OGI	0.65	1.61	2.68
Semi-annual OGI	0.41	0.97	1.64
Quarterly OGI	0.29	0.62	1.09
Bi-monthly OGI	0.25	0.55	0.93
Monthly OGI	0.19	0.43	0.78

[1]See Table 2 for percent of components leaking at these ratios.

[9] The initial OGI FEAST analysis was performed with only 100 runs. With 20 sites per run, this assessment considered emissions across 2,000 sites. Given the relatively small number of sites modelled (for Monte Carlo analyses considering highly variable emission sources like fugitive emission components) the average emissions determined in this series of results have higher uncertainty than subsequent simulations where a higher number of runs were made. Nonetheless, for a given model plant and leak generation rate setting, all monitoring frequencies were run in a single simulation, with a common set of leaks generated, so the emissions for a given column in Tables 3 through 6 are directly comparable.

Table 4. Emission Simulations Results for Model Plant 2

Monitoring Program	Average Emissions (tons CH_4/year) per Site for Leak Generation Rate Levels		
	Low[1]	Medium[1]	High[1]
Baseline	2.66	4.68	9.61
Annual OGI	1.48	2.56	5.62
Semi-annual OGI	0.87	1.58	3.37
Quarterly OGI	0.60	1.07	2.26
Bi-monthly OGI	0.51	0.90	1.90
Monthly OGI	0.41	0.72	1.50

[1]See Table 2 for percent of components leaking at these ratios.

Table 5. Emission Simulations Results for Model Plant 3

Monitoring Program	Average Emissions (tons CH_4/year) per Site for Leak Generation Rate Levels		
	Low[1]	Medium[1]	High[1]
Baseline	7.18	14.08	28.15
Annual OGI	3.77	7.94	15.46
Semi-annual OGI	2.33	4.79	9.31
Quarterly OGI	1.56	3.24	6.22
Bi-monthly OGI	1.30	2.65	5.20
Monthly OGI	1.07	2.15	4.09

[1]See Table 2 for percent of components leaking at these ratios.

Table 6. Emission Simulations Results for Model Plant 4

Monitoring Program	Average Emissions (tons CH_4/year) per Site for Leak Generation Rate Levels		
	Low[1]	Medium[1]	High[1]
Baseline	8.51	15.40	31.10
Annual OGI	4.52	8.76	16.84
Semi-annual OGI	2.78	5.29	10.16
Quarterly OGI	1.90	3.53	6.74
Bi-monthly OGI	1.54	2.93	5.53
Monthly OGI	1.25	2.35	4.40

[1]See Table 2 for percent of components leaking at these ratios.

Table 7. Typical Percent Emission Reductions by OGI Monitoring Frequency

Monitoring Program	Percent Emission Reduction from Baseline
Annual OGI	45%
Semi-annual OGI	67%
Quarterly OGI	77%
Bi-monthly OGI	81%
Monthly OGI	85%

4.2 Emission Estimate Results for AVO Monitoring

As an alternative to OGI monitoring, we attempted to assess the emission reduction that could be achieved using AVO monitoring methods. Unlike OGI monitoring, for which we have specific minimum detection quantities specified in the method (60 g/hr requirement in proposed NSPS OOOOb), we have no specific information by which to estimate AVO leak detection sensitivities. Therefore, we initially ran for different sets of AVO monitoring detection limits as summarized in **Table 8**.

Table 8. Probability of Detection Inputs for AVO Monitoring Options

AVO Option	Leak Rate at Specified Probability of Detection (g/hr)				
	0%	25%	50%	75%	100%
AVO1	61	77	94	108	122
AVO2	61	92	122	184	245
AVO3	122	153	184	214	245
AVO4	122	184	214	367	490

We evaluated emissions for the same five monitoring frequencies for which OGI monitoring was evaluated (i.e., annually, semi-annually, quarterly, bi-monthly, and monthly). Example results for Model Plant 1 at a leak generation rate of 1% are provided in **Exhibit 9**.

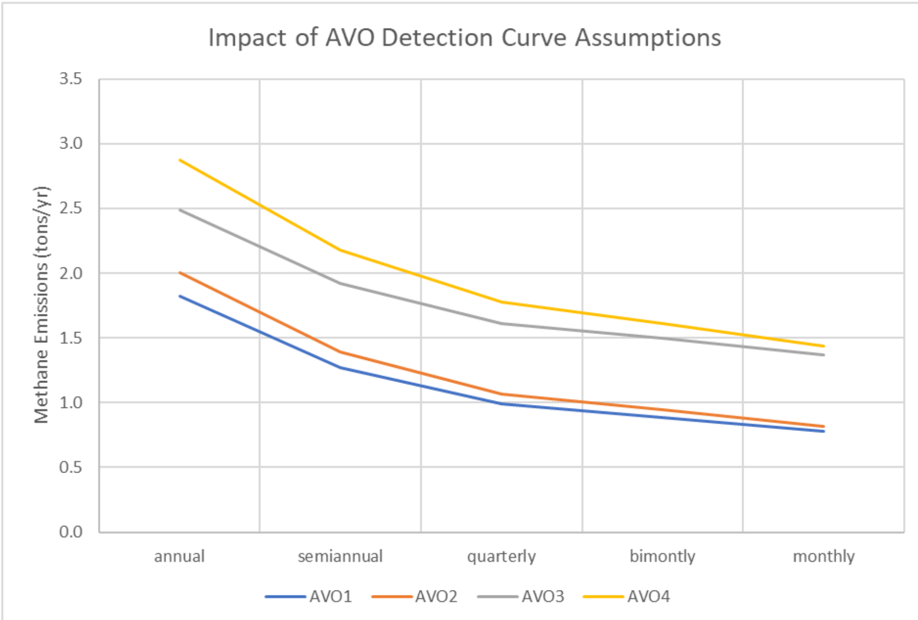

Exhibit 9. Emission results for Model Plant 1 for different AVO survey sensitivities and frequencies using a 1% leak generation rate.

The results presented in **Exhibit 9** indicate little difference in the emission results between AVO options 1 and 2. Similarly, emission results between AVO options 3 and 4 are quite similar, especially as the monitoring frequency is increased. These results suggest that the performance of a monitoring method is more strongly dependent on the lower limit of detection than it is on the upper limit of detection.

The emissions projected for annual AVO monitoring using the detection limits for AVO option 3 were very similar to the "baseline" emissions, so the results for AVO option 3 were used for further comparisons. The emissions for various monitoring frequencies for AVO option 3 for Model Plants 1, 2, and 4 are presented in Table 9.

Table 9. Methane Emissions for AVO Monitoring

AVO Option	Annual Methane Emissions (U.S. tons/yr)					
	MP1; Low LGR[1]	MP1; Mid LGR[1]	MP2; Low LGR[1]	MP2; Mid LGR[1]	MP4; Low LGR[1]	MP4; Mid LGR[1]
Annual	1.25	2.49	2.36	4.85	7.33	14.67
Semiannual	0.97	1.92	1.83	3.72	5.54	11.14
Quarterly	0.81	1.61	1.54	3.10	4.60	9.21
Bimonthly	0.74	1.49	1.44	2.87	4.28	8.50
Monthly	0.68	1.37	1.32	2.64	3.89	7.77

[1]MP = Model Plant; LGR = leak generation rate. Low and mid LGRs are specified in Table 2.

4.3 Emission Estimate Results for Combined OGI/AVO Monitoring Options

We also evaluated the emissions projected for a combined OGI/AVO monitoring option. Specifically, we considered the options of adding AVO monitoring to a "baseline OGI" monitoring option. For Model Plants 1 and 2, the "baseline OGI" monitoring frequency was assumed to be semiannual, and we considered adding quarterly, bimonthly, or monthly AVO monitoring. Quarterly AVO monitoring, in this example, would imply the facility would monitor 4 times a year, twice using OGI and twice using AVO monitoring. For Model Plant 4, the "baseline OGI" monitoring frequency was assumed to be quarterly, and we considered adding bimonthly or monthly AVO monitoring. We note that bimonthly AVO only overlaps with two of the quarterly monitoring methods. Assuming OGI is conducted initially, which we refer to as "time zero", AVO monitoring would be conducted on months 2, 4, 8, and 10 and OGI monitoring would be conducted on months 3, 6, 9 and 12. For this analysis, we used the probability of detection limits for AVO option 3 from Table 8, except that we set the maximum probability of detection to 90%. We used the emission rate value shown in Table 8 as the 90% 90% probability. The emissions for various OGI/AVO combination monitoring options for Model Plants 1, 2, and 4 are presented in **Table 10**.

Table 10. Methane Emissions for Combined OGI/AVO Monitoring Options

AVO Option	Annual Methane Emissions (U.S. tons/yr)					
	MP1; Low LGR[1]	MP1; Mid LGR[1]	MP2; Low LGR[1]	MP2; Mid LGR[1]	MP4; Low LGR[1]	MP4; Mid LGR[1]
Baseline Semiannual OGI	0.904	0.419	0.847	1.65	N/A	N/A
Baseline Quarterly OGI	N/A	N/A	N/A	N/A	1.73	3.45
Combined Quarterly OGI/AVO	0.69	0.315	0.640	1.24	N/A	N/A
Combined Bimonthly OGI/AVO	0.58	0.265	0.545	1.04	1.42	2.83
Combined Monthly OGI/AVO	0.50	0.231	0.469	0.90	1.25	2.48

[1]MP = Model Plant; LGR = leak generation rate. Low and mid LGRs are specified in Table 2.

4.4 Discussion of Modeled Emission Estimates

Rutherford, et al., 2021, conducted Monte Carlo analyses using leak frequency data, leak emission rates, and component counts for equipment to develop average emission rates for equipment and for production sites. The average equipment level emission reported by Rutherford, et al., (2021; Supplemental Information) include:

- Gas wellhead: 3.35 kg CH_4/day (1.35 tons CH_4/yr)
- Gas meter: 2.66 kg CH_4/day (1.07 tons CH_4/yr)
- Gas separator: 3.72 kg CH_4/day (1.50 tons CH_4/yr)

For Model Plant 1, which is a single wellhead with meter and piping, Rutherford equipment emission factors suggest this model plant's emissions would be 2.42 tons CH_4/yr. This is similar, but slightly lower than the emissions projected for Model Plant 1 using a leak generation rate of 1% within FEAST. While Rutherford, et al., (2021) used a much lower percent of equipment leaking (weighted-average across different component types) than 1% leak generation rate assumed in FEAST, Rutherford also had much higher component counts per major equipment than projected using the East/West component counts from Table W-1B from 40 CFR part 98, subpart W, which are from the joint study between EPA and the Gas Research Institute (GRI) of methane emission from the natural gas industry (EPA/GRI, 1996). For Model Plant 2, Rutherford's equipment factor for gas equipment would project emissions of 4.84 tons CH_4/yr. Rutherford's equipment factors for oil wellheads and oil meters are about half those of gas equipment. The net result is that Rutherford's emission estimates for gas wells are similar to the baseline emission estimates modeled when using the 1% leak generation rate in FEAST and Rutherford's emission estimates for oil wells are similar to the baseline emission estimates modeled when using the 0.5% leak generation rate in FEAST.

Note that the model input leak generation rate of 1% would indicate that, on average, 6.1 leaks would be generated per year per site for Model Plant 3 (with 612 components). These leaks are drawn randomly from the leak distribution data set. Many of these leaks are below the detection limit of an OGI instrument that is only required to detect 60 g/hr leak. We used the number of repairs made in the fifth year as the annual leak detection (and repair) rate. The annual leak detection rate was, for the most part, independent of the monitoring frequency used.[10] The annual number of OGI detected (and repaired) leaks averaged 3.5 for Model Plant 3 or approximately 57% of the leak generation rate regardless of the monitoring frequency. Thus, if an annual OGI survey is conducted that detects leaks in 0.6 percent of the monitored components, that would be directly comparable to the 1% leak generation rate used in the model.

[10] Annual frequency generally had lower number of repairs; the number of repairs for other frequencies were identical within the random variations of the model simulation. We believe there are two reasons why annual number of repairs were slightly lower for annual monitoring than other monitoring frequencies. First, the repairs made in the fifth year for the annual monitoring frequency are from leaks identified on day 1 of year 5, which considers only the build-up of small leaks in the first 4 years. Other monitoring frequencies include build-up of leaks (and subsequent detection and repair) for some portion of year 5. So, there was less time for annual monitoring to reach "equilibrium." Second, for leaks in the middle of the probability of detection, having multiple monitoring of leaks in that range in a year should increase the likelihood of detecting a leak in that range. We expect longer simulation periods would result in build-up of leaks in that middle range so that annual monitoring would reach the same equilibrium number of repairs made per year as the other monitoring frequencies.

Using a FEAST leak generation rate of 0.5% would be comparable to an annual OGI survey detecting leaks in 0.3 percent of the monitored components.

This also indicates that, based on the distribution of leak rates identified in component-specific emission measurement studies, about 20 to 40 percent of the leaks "generated" at a site will be below the detection limits of a typical OGI instrument. These small leaks will tend to accumulate over time. Most simulation models use an auto-repair rate to prevent the build-up of these small leaks. As noted previously, we decided to set the auto-repair rate to zero because the auto-repair function would fix very small leaks at the same rate as larger leaks, which is unlikely. Even with the build-up of these small leaks over 5 years, these small leaks do not appear to significantly contribute to the model plant emissions. Considering the repaired leaks for monthly monitoring frequency occur for an average of 45 days (start mid-month so present 15 days before detection, and repair completed 30 days after detection), we project that these small, non-repaired leaks represent only 3 or 4 percent of the baseline emissions.

5. FEAST Run Results with Large-Emitters for Sitewide Monitoring Equivalence

The next model simulations were conducted to determine when mobile, aerial, or drone monitoring, collectively referred to as site-wide monitoring, can achieve the same emission levels as ground-based OGI monitoring. For these analyses, we included large emission events and conducted analyses to determine equivalency to semiannual ground-based OGI surveys for small sites (specifically for Model Plant 2) and quarterly ground-based OGI surveys for larger sites (specifically for Model Plant 4).

Initially, site-wide monitoring was conducted at the following leak detection limits (representing 100% detection level).

- 1 kg/hr
- 5 kg/hr
- 15 kg/hr
- 30 kg/hr
- 60 kg/hr

Monitoring frequencies that were evaluated were primarily monthly and bi-monthly and included site-wide surveys only or site-wide surveys with annual OGI monitoring "backstop." All leaks detected via a site-wide survey deployed a ground-level OGI monitoring crew to monitor all fugitive emission components at the site and repair all leaks identified. This OGI monitoring was identical to the quarterly OGI monitoring "baseline" (60 g/hr 100% detection level; repair within 30 days of initial screening survey).

We looked initially at large-emitter rates of 0.5%, 1%, and 2% to understand the impact of large-emitter generation rates on emissions. We quickly found out that the inclusion of large-emitters greatly increased the variability of the model results. When modeling fugitive components, there are 612 components per site (for Model Plant 4) so the fieldwide (20 sites) emission results included simulation of 12,240 component sources. With the large pool of sources, the individual Monte Carlo runs were quite similar and the initial modeling runs were conducted using only 100 iterations (for a total of 2,000 sites modeled). With the inclusion of large-emitters with only 2 potential sources per site (for Model Plant 4) the variability by site and by field (i.e., group of 20 sites) is very large, highlighting the significant impact of large-emitter emissions on the fieldwide emissions. Due to the high variability of emissions when including large-emitters, a significantly higher number of Monte Carlo simulations are needed to yield consistent results.

During a given simulation, we included the baseline OGI monitoring survey, a sitewide screening survey that would call for the ground-based survey for a particular site only if emissions were detected ("no backstop"), and a sitewide screening survey that would call for the ground-based survey for a particular site both if emissions were detected and annually regardless of when a ground-based survey was last deployed ("with backstop"). These simulations occurred on the same set of leaks generated, so the comparison on the performance of the options is most directly comparable. We noted that, for simulations that had high baseline emissions, the emissions of the sitewide monitoring options would also increase. However, the relative performance of the sitewide monitoring options tended to be better when the baseline emissions were higher, indicating stronger impact of large-emitters. This was also evident with comparisons of modeling runs using different large-emitter leak frequencies. The higher the large-emitter leak frequency, the more likely it was that the more frequent (but less sensitive) sitewide monitoring would perform better than ground-based OGI monitoring.

5.1 Equivalency Matrix at Medium Leak Generation Rates

We conducted our formal equivalency modeling using median leak generation rates for equipment components are presented in Table 2 and using a 1% leak generation rate for large-emitters for both Model Plants 2 and 4. We selected this rate based on data from Zavala-Araiza, et al., (2017), which showed about 1 percent of sites emitting over 26 kg/hr.[11] While the augmented large-emitter distribution has more data in the 10 to 30 kg/hr range, data below 26 kg/hr (7.22 g/sec) represent less than 25 percent of the dataset. Also, we assume 2 large-emitter sources per site for Model Plants 3 and 4, so the 1 percent leak generation rate combined with these other assumptions yields a sitewide large-emitter leak frequency of about 1.5 percent of sites with large emission events. For Model Plant 2, the sitewide large-emitter leak frequency would be about 0.75 percent of sites with large emission events because there is only one large-emitter source assumed at the site. In a typical field, there will be a combination of facility types, with some small facilities (similar to Model Plant 2) and some larger facilities (similar to Model Plants 3 and 4). Therefore, our 1% large-emitter leak generation rate assumption is, in general, consistent with the large-emitter leak frequency observed by Zavala-Araiza, et al., (2017).

A summary of the model simulations conducted are summarized in **Tables 11 and 12** for Model Plants 2 and 4, respectively. The "baseline" OGI monitoring frequency for Model Plant 2 simulations was semiannual; the "baseline" OGI monitoring frequency for Model Plant 4 simulations was quarterly. Note that the inclusion of large-emitters significantly impacted the expected emissions from the fugitive emission program. For Model Plant 2, annual emissions with semiannual OGI monitoring without large-emitters were 1.58 tons/yr, while including large-emitters, the annual average emissions were approximately 11.6 tons/yr, or a factor of 7 times higher. Similarly, for Model Plant 4, annual emissions with quarterly OGI monitoring without

[11] Zavala-Araiza, Daniel, et al. 16 Jan 2017, https://doi.org/10.1038/ncomms14012.

large-emitters were 3.53 tons/yr; including large-emitters, the annual emissions were approximately 15.7 tons/yr, or more than a factor of 4 times higher.

For a given Monte Carlo iteration, leaks are randomly generated for the various sites across the 5-year modeling period and the performance of the different monitoring methods being evaluated in that simulation all encounter the same set of leaks. So, if a 120 kg/hr large emission event is generated at Site 7 on month 2 of year 5 during a given iteration, all monitoring methods being evaluated experience that leak and simulate the identification and repair of that leak based on the monitoring frequency and sensitivity being assessed. For any given modeling run, we ran the "baseline" OGI monitoring program (semi-annual for Model Plant 2 and quarterly for Model Plant 4), the site-wide detection limit with an annual OGI survey and that same site-wide detection limit by itself (with no annual OGI survey). Thus, each row in Tables 11 and 12 represent a consistent set of leaks generated by which the performance of the monitoring methods can be evaluated.

Table 11. Results of Emission Simulations Results for Model Plant 2 Including Large-Emitters

Sitewide Monitoring Program		No. of Runs	Average Emissions (tons CH_4/year) per Site for Leak Generation Rate Levels		
Frequency (Days Between Surveys)	Detection Limit (kg/hr)		Semiannual OGI	Sitewide Survey	Sitewide Survey with Annual OGI
Semiannual (182)	1	500	12.61	13.75	11.84
Triannual (121)	1	500	11.23	9.51	8.64
Triannual (121)	2	1500	8.38	9.13	7.09
Triannual (121)	5	500	12.18	18.89	13.04
Triannual (121)	15	500	9.33	23.47	10.35
Quarterly (91)	1	430	13.83	9.10	8.33
Quarterly (91)	2	500	12.96	9.90	8.04
Quarterly (91)	5	500	11.12	12.83	7.43
Quarterly (91)	15	778	14.19	24.08	10.80
Quarterly (91)	30	855	13.68	26.87	14.17
Bimonthly (60)	15	500	12.55	21.78	8.61
Bimonthly (60)	30	500	11.31	25.29	12.58
Monthly (30)	30	747	11.44	23.94	11.07
Monthly (30)	60	100	8.79	26.00	13.27

Table 12. Results of Emission Simulations Results for Model Plant 4 Including Large-Emitters

Sitewide Monitoring Program		No. of Runs	Average Emissions (tons CH_4/year) per Site for Leak Generation Rate Levels		
Frequency (Days Between Surveys)	Detection Limit (kg/hr)		Quarterly OGI	Sitewide Survey	Sitewide Survey with Annual OGI
Quarterly (91)	1	2000	16.50	17.53	16.54
Bimonthly (60)	2	1000	16.60	15.69	13.92
Bimonthly (60)	4	2387	16.00	19.12	15.83
Bimonthly (60)	5	2000	15.60	19.90	15.85
Bimonthly (60)	10	1000	16.05	26.62	16.57
Monthly (30)	4	1000	16.02	15.54	13.26
Monthly (30)	5	1392	15.60	15.87	12.71
Monthly (30)	15	1000	16.82	30.05	15.78
Monthly (30)	30	1000	15.09	49.79	15.05

Because the baseline OGI monitoring program was included in each run (for a given model plant), we could determine a long-term average emission rate for this monitoring option across all of the various runs. However, because of the large and random impact of large-emitter events on the emissions and monitoring method performance, we did not compare individual sitewide monitoring results with this long-term average for baseline OGI. The high variability in the large-emitter simulations would require even higher number of runs for each sitewide simulation to be more directly comparable to this long-term average.

An additional finding when conducting these runs is that it was much more difficult to assess equivalency when the sitewide monitoring frequency is not a direct integer division of the ground-based survey frequency. Specifically, triannual frequency compared to semiannual frequency and bimonthly frequency compared to quarterly. With these monitoring options, it is possible, under certain instances, that some large-emitters will emit for longer periods under the sitewide program than the baseline OGI option. For example, consider triannual surveys conducted as an alternative to semiannual OGI monitoring. If a large-emitter begins at day 150, 30 days after the triannual survey was conducted, it will be identified in 30 days under the semiannual monitoring frequency but could persist up to 90 days before detection under the triannual monitoring option. In the long run, the shorter triannual monitoring frequency can perform better than semiannual, but there is greater variability in the Monte Carlo results because of these scenarios, making it more difficult to determine the long-term equivalency of the programs. For these options, we conducted a higher number of runs to better assess the long-term equivalency of the monitoring options. When the sitewide monitoring frequency is a direct integer division of the baseline OGI survey frequency, the sitewide option will always perform as well or better than the ground-based OGI survey as it pertains to detectable large-emitters.

5.2 Sensitivity Analysis

We evaluated a small number of site-wide screening methods to see how the different assumptions impact the results presented in Section 5.1 of this memorandum. **Table 13** shows sensitivity runs where the large-emitter leak generation rate was maintained at 1% but the fugitive emission component leak generation rate was set to the low inputs in Table 2. When lowering the leak generation rate for fugitive components, the site emissions go down. The main exception to this is the 1 kg/hr site-wide detection limit at a quarterly monitoring frequency (with an OGI backstop) for Model Plant 4. At the "mid" leak generation rate for fugitive components, this monitoring option appeared to be equivalent to quarterly OGI, but when using the "low" fugitive leak generation rate, the 1 kg/hr site-wide detection limit at a quarterly monitoring frequency (with an OGI backstop) for Model Plant 4 performed significantly worse than quarterly OGI.

We also conducted a limited number of runs with the large-emitter leak generation rate for Model Plants 2 and 4 set to 0.5%. Since Model Plant 4 was assumed to have two large-emitter potential sources, lowering the leak generation rate for Model Plant 4 should yield large-emitting sites near the 1% of sites with emissions exceeding 26 kg/hr reported by Zavala-Araiza, et al., (2017). The 0.5% large-emitter leak generation rate may also be more representative of basins that may have fewer large-emitter sites (relative to the total number of sites in the basin). **Table 14** summarizes the sensitivity runs when using a 0.5% leak generation rate for large-emitters. In general, with a lower large-emitter leak generation rate, lower minimum detection thresholds would be needed for the site-level method (at a given monitoring frequency) to have equivalent performance as OGI when compared to the equivalency matrix at a 1% large-emitter leak generation rate.

Table 13. Sensitivity Emission Simulations Results Using Low Leak Generation Rates (0.5%) for Fugitive Emission Components and 1% Leak Generation Rate for Large-Emitters

Sitewide Monitoring Program		No. of Runs	Average Emissions (tons CH_4/year) per Site for Leak Generation Rate Levels		
Frequency (Days Between Surveys)	Detection Limit (kg/hr)		Quarterly OGI	Sitewide Survey	Sitewide Survey with Annual OGI
Model Plant 2 Sensitivity Runs: LGRs of 0.5% Fugitive Components, 1% Large-Emitter					
Semiannual (182)	1	500	8.42	9.44	8.26
Quarterly (91)	2	500	9.27	8.25	6.34
Quarterly (91)	5	500	9.44	11.15	6.94
Quarterly (91)	15	496	10.84	14.82	8.48
Monthly (30)	30	500	10.15	13.66	8.02
Model Plant 4 Sensitivity Runs: LGRs of 0.5% Fugitive Components, 1% Large-Emitter					
Quarterly (91)	1	500	12.33	13.79	13.01
Twice a Quarter (45)	4	1111	15.64	16.62	13.67
Twice a Quarter (45)	10	500	14.56	23.24	14.07
Twice a Quarter (45)	15	1207	16.04	32.41	16.61
Monthly (30)	4	1000	16.02	15.54	13.26

Table 14. Sensitivity Emission Simulations Results Using Low Leak Generation Rates (0.5%) for both Fugitive Emission Components and for Large-Emitters

Sitewide Monitoring Program		No. of Runs	Average Emissions (tons CH_4/year) per Site for Leak Generation Rate Levels		
Frequency (Days Between Surveys)	Detection Limit (kg/hr)		Quarterly OGI	Sitewide Survey	Sitewide Survey with Annual OGI
Model Plant 2 Sensitivity Runs: LGRs of 0.5% Fugitive Components, 0.5% Large-Emitter					
Quarterly (91)	1	997	6.54	5.08	4.35
Quarterly (91)	2	984	4.90	5.48	3.72
Model Plant 4 Sensitivity Runs: LGRs of 0.5% Fugitive Components, 0.5% Large-Emitter					
Monthly (30)	1	500	7.89	7.58	6.37
Monthly (30)	2	415	6.67	8.61	5.76

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