



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

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Regulatory Impact Analysis for the Additional Reconsideration Standards of Performance for
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and Natural Gas Sector Climate Review

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1 INTRODUCTION

1.1 Background

On March 8, 2024, the Environmental Protection Agency (EPA) finalized a rule to reduce volatile organic compound (VOC) and methane emissions from the Crude Oil and Natural Gas source category (“March 2024 Final Rule”) (89 FR 16820). This rule finalized New Source Performance Standards (NSPS) for greenhouse gas (GHG) and VOC emissions from new, modified, and reconstructed sources in this source category, codified in 40 CFR part 60 (subpart NSPS OOOOb). This rule also finalized Emissions Guidelines (EG) for GHG emissions from existing sources in this source category, codified in EG OOOOc.

On July 31, 2025, the EPA promulgated an interim final rule (IFR) (“July 2025 IFR”) (90 FR 35966) which extended deadlines for certain provisions in the NSPS OOOOb related to control devices, equipment leaks, storage vessels, process controllers, and covers and closed vent systems. Within that IFR, the EPA also extended the date for future implementation of the Super Emitter Program and extended the state plan submittal deadline in EG OOOOc to January 22, 2027. The EPA promulgated a final rule in December 2025 which responded to the July 2025 IFR comments and reaffirmed the conclusions and the regulatory amendments made in the IFR (“December 2025 Final Rule”) (90 FR 55671). The EPA is now proposing to reconsider additional standards of the March 2024 Final Rule. A key proposed provision of this action is to establish a subcategory and set standards for *marginal* well sites, defined as sites producing less than or equal to 15 barrels of oil equivalent (BOE) per day. The EPA is also proposing a number of other changes, including rescission of the Super Emitter Program.

In accordance with E.O. 12866, the guidelines of the Office of Management and Budget Circular A-4 (OMB, 2003) and the EPA’s *Guidelines for Preparing Economic Analyses* (U.S. EPA, 2024), this regulatory impact analysis (RIA) analyzes the nationwide benefits and costs of the proposed additional reconsideration.¹ The RIA also examines expected economic impacts of the proposed action.

¹ Throughout the RIA, the proposed additional reconsideration is referred to as the “proposed reconsideration,” “proposed rule,” or “proposed action.”

1.2 Baseline and Regulatory Requirements

For conducting regulatory impact analyses, the EPA evaluates the impacts of regulatory actions relative to a baseline that represents the world without the action. In this case, we characterize impacts for the proposed reconsideration standards² where the baseline includes the March 2024 Final Rule regulatory requirements on the Crude Oil and Natural Gas source category and the December 2025 Final Rule.

Throughout this document, we focus the analysis on the requirements that result in quantifiable compliance cost or emissions changes relative to the baseline. We do not analyze the regulatory impacts of all proposed reconsideration standards because we either lack sufficient data that we can readily use for analysis or believe the provisions would not result in appreciable compliance cost or emissions impacts.

Table 1-1 summarizes the key aspects of the reconsideration and categorizes whether we use a quantitative or qualitative analysis approach for each aspect. We quantify impacts for two aspects: the establishment of a subcategory for marginal well sites with attendant standards that differ from those established in the March 2024 Final Rule and the revocation of the Best System of Emission Reductions (BSER) for associated gas. In addition, the EPA is co-proposing to apply the well site subcategorization to conventional, rather than marginal, well sites. The EPA is proposing to define a conventional well as any well drilled for the purpose of producing oil or natural gas that is not an unconventional well, where an “unconventional” well means any bore hole drilled or being drilled for the purpose of or to be used for the production of oil and natural gas from an unconventional formation.³ We also quantify estimated impacts for the co-proposed option, with the results summarized in Section 7.3.

We do not quantify impacts for the Super Emitter Program rescission, certain exemptions from monitoring and performance testing requirements for temporary control devices, targeted additional allowances for temporary flaring episodes, certain exemptions and changes to requirements for covers and closed vent systems, and an exemption for high-pressure process controllers at compressor stations from the zero emissions standards. The table discusses why the

² Throughout the RIA, the use of “we,” “us,” or “our” refers to the EPA.

³ For this action, the EPA is proposing the several definitions associated with the co-proposed option such as a definition of “unconventional formation”. Please see Section III.K.2 of the preamble for more details.

impacts of those aspects are not quantified and a qualitative analysis of the potential impacts of those aspects is provided in Section 7.2. Overall, we believe that this analysis sufficiently captures the most significant impacts of the proposed action.

Table 1-1 Analysis Approach for Proposed Reconsideration Requirements

Action	Analysis Approach
Subcategorization and standard setting of marginal (proposed option) or conventional (co-proposed option) well sites	Quantitative^a
Removal of the Best System of Emission Reduction (BSER) for associated gas	Quantitative
Rescission of the Super Emitter Program in NSPS OOOO, OOOOa, OOOOb, and EG OOOOc	Qualitative due to lack of specific information on the frequency, intensity, and cost to mitigate super emitter events not captured by the other rule requirements; how often third parties would conduct monitoring activities; what those activities would entail; how often they would detect super-emitters; how often those detections would provide sufficient and timely information for companies to respond; and how often reported detections would result in false notifications and what the costs would be to operators of responding to such notifications. ^c
Limited exemptions from monitoring and performance testing requirements for temporary control devices	Qualitative due to lack of information on the current and future stocks of temporary control devices and process controllers.
Targeted amendments to associated gas provisions in NSPS OOOOb and EG OOOOc to allow for additional episodes of temporary flaring	Qualitative due to lack of specific information on the frequency and duration of gas service interruptions or instances in which gathering infrastructure lags commencement of production at the well site.
Changes to requirements for covers and closed vent systems	Qualitative because changes are largely definitional, and we lack specific information on how they would impact compliance costs and emissions. ^d
Exemption of high-pressure process controllers at compressor stations from zero emissions standards	Qualitative because analysis for the March 2024 Final Rule suggests impacts would be orders of magnitude smaller than the impacts quantified in this rule. ^e

^a The results throughout most of the document pertain to the proposed marginal site subcategorization. Results for the co-proposed option of conventional site subcategorization are presented in Section 7.3.

^b The July 2025 IFR extended the state plan submittal date of the March 2024 Final Rule from March 9, 2026, to January 22, 2027. See 90 FR 35966 (July 31, 2025) for more information.

^c The EPA also did not attempt to quantify the impacts of the super-emitter response program in the March 2024 Final Rule for the reasons listed in this table.

^d The changes related to covers and closed vent systems are related to language around design requirements and clarifications on compliance parameters to be responsive to concerns raised by petitioners. For more information on the specific proposed provisions, see section III.G.2 of the preamble.

^e The zero emissions standards for transmission and storage compressor station process controllers accounted for around 1% of the quantified estimated cost and emissions impacts in the 2024 Final Rule RIA. Limiting the impacts further to high-pressure controllers suggests that this aspect of the rule would be very small relative to the overall scale of the estimated impacts of the proposed action.

Table 1-2 summarizes the baseline and proposed reconsideration standards of performance for marginal well sites for NSPS OOOOb and EG OOOOc;⁴ in the case of the co-proposed option, the subcategory is defined as conventional rather than marginal well sites. The March 2024 Final Rule did not subcategorize based on production level nor well type in determining the BSER, so the baseline scenario reflects the requirements set for all well sites in that rule. Both the baseline and proposed requirements are nearly identical for the NSPS and EG. For EG OOOOc, the standards are presumptive; actual requirements will be determined as part of the state planning process. In all cases, the proposed standards are expected to be as or less stringent than the current requirements, trading off increased emissions with cost savings.

There are six emission sources covered in our analysis: fugitive emissions components, process controllers, pneumatic pumps, storage vessels, associated gas from oil wells, and liquids unloading. The proposed requirements for fugitive components consist of various optical gas imaging (OGI) and auditory, visual, and olfactory (AVO) inspection regimes in which periodic monitoring identifies leaks that are then repaired. The baseline requirement for controllers and pumps is a zero-emission standard, which could be met by, for example, replacing gas-driven devices with electronic devices. The proposed requirements for pumps are to route emissions to an existing control device if one is already available onsite. For controllers, the proposed requirements are to (a) meet the same emissions limit for continuous bleed controllers as established in the NSPS OOOOa; and (b) include intermittent bleed controllers in the fugitive inspection program, requiring quarterly AVO inspections and repair of malfunctions. The requirements for storage vessels and associated gas depend on the potential to emit (PTE) from those sources in the absence of any control. There are no proposed changes to the storage vessel requirements: we assume that operators meet the 95 percent control standards by flaring emissions. For associated gas, the EPA is proposing to remove any requirements to route to a sales line (or other beneficial use) for marginal wells, and instead only requiring 95 percent control if emissions exceed 20 tons per year (tpy) of methane. Finally, the EPA is proposing to remove the requirement that operators apply best management practices during liquids unloading events for marginal sites.

⁴ See the preamble for a more comprehensive description of the proposed additional reconsideration standards.

Table 1-2 Summary of Baseline Requirements and Requirements under the Proposed Reconsideration for Subcategorized Well Sites for NSPS OOOOb & EG OOOOc

Source	Baseline	Proposed Reconsideration for Subcategorized Well Sites (Marginal wells under the proposed option; Conventional wells under the co-proposed option)
NSPS OOOOb		
<i>Fugitive Emissions^a</i>		
Wellhead only, single well site	Quarterly AVO	Quarterly AVO
Wellhead only, multiple well site	Quarterly AVO, Semiannual OGI	Quarterly AVO
Small well site ^b	Quarterly AVO	Quarterly AVO
Large well site ^c	Bimonthly AVO, Quarterly OGI	Quarterly AVO
<i>Pneumatic Pumps^d</i>	Zero emissions	Route to existing control device
<i>Process Controllers</i>	Zero emissions	Low bleed, Quarterly AVO
<i>Storage Vessels^e</i>		
PTE ≥ 6 tpy VOC or PTE ≥ 20 tpy CH ₄	95% control	95% control
PTE < 6 tpy VOC and PTE < 20 tpy CH ₄	No requirement	No requirement
<i>Associated Gas</i>		
PTE ≥ 20 tpy CH ₄	Route to sales	95% control
PTE < 20 tpy CH ₄	Route to sales	No requirement
<i>Liquids Unloading</i>	Best management practices	No requirement
EG OOOOc		
<i>Fugitive Emissions^a</i>		
Wellhead only, single well site	Quarterly AVO	Quarterly AVO
Wellhead only, multiple well site	Quarterly AVO, Semiannual OGI	Quarterly AVO
Small well site ^b	Quarterly AVO	Quarterly AVO
Large well site ^c	Bimonthly AVO, Quarterly OGI	Quarterly AVO
<i>Pneumatic Pumps^d</i>	Zero emissions	Route to existing control device
<i>Process Controllers</i>	Zero emissions	Low bleed, Quarterly AVO
<i>Storage Vessels^e</i>		
PTE ≥ 20 tpy CH ₄	95% control	95% control
PTE < 20 tpy CH ₄	No requirement	No requirement
<i>Associated Gas</i>		
PTE ≥ 40 tpy CH ₄	Route to sales	95% control
20 tpy CH ₄ ≤ PTE < 40 tpy CH ₄	95% control	95% control
PTE < 20 tpy CH ₄	95% control	No requirement
<i>Liquids Unloading</i>	Best management practices	No requirement

^a NSPS OOOOb-affected sites are subject to semiannual OGI monitoring requirements. Those sites would then become subject to EG OOOOc requirements whenever the Emissions Guidelines take effect.

^b Small well sites are defined as single well sites with a single piece of major equipment and no tank battery.

^c Large well sites are defined as multiple well sites with a single piece of major equipment, or any site with (1) two or more pieces of major equipment; (2) one piece of major equipment and a tank battery; or (3) a controlled tank battery.

^d The zero emissions standard for pumps in the baseline scenario only applies to sites with electric power or have three or more diaphragm pumps. Otherwise, pumps must be routed to a preexisting on-site control device. However, we assume that, regardless of the number of pumps at the site, operators choose to switch to zero emitting devices since they already need to pay the capital cost to power the controllers at the site.

1.3 Summary of the Benefit-Cost Analysis

A summary of the benefit-cost analysis results is shown below. The monetized benefits of the proposed action are captured by estimates of economic surplus, which is the sum of estimated changes to compliance costs, offset by reductions in the value of natural gas capture due to less stringent compliance activity, and additional changes from energy market impacts beyond the direct impact of changes in compliance costs and gas capture. We do not monetize costs of the proposed action; however, we quantify the emission increases of methane, VOC, and HAP for which we would anticipate there being unquantified costs resulting from negative health outcomes and environmental damages. All dollar estimates are in 2024 dollars. All quantified impacts are estimated for the years 2027 to 2050 relative to a baseline where the March 2024 Final Rule and the December 2025 Final Rule requirements are in place. The initial analysis year is 2027 as the rule is expected to take effect by the end of 2026. The final year of analysis is 2050 to reflect when U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) projections stop.

Table 1-3 presents the estimated monetized change in economic surplus for the proposed additional reconsideration. The table presents the present value (PV) and equivalent annual value (EAV) of the increases in monetized surplus relative to the baseline, estimated using discount rates of 3 and 7 percent. The table includes estimated changes to compliance costs (including the value of product recovery) and additional changes to the net surplus beyond compliance costs from energy market impacts (i.e., residual producer and consumer surplus changes after accounting for compliance cost and product recovery changes). These values reflect an analytical time horizon of 2027 to 2050, are discounted to 2025, and presented in 2024 dollars.

Table 1-3 Projected Increase in Monetized Economic Surplus for the Proposed Reconsideration Standards, 2027-2050 (million 2024\$, discounted to 2025)

		3 Percent Discount Rate		7 Percent Discount Rate	
		PV	EAV	PV	EAV
<i>Proposed Reconsideration</i>	Compliance Cost Savings	\$42,000	\$2,500	\$29,000	\$2,500
	Savings from Energy Market Impacts	\$3,000	\$200	\$3,000	\$300
	Net Surplus	\$45,000	\$2,700	\$32,000	\$2,800
<i>Co-Proposal</i>	Compliance Cost Savings	\$39,000	\$2,300	\$27,000	\$2,300
	Savings from Energy Market Impacts	\$370	\$22	\$1,000	\$100
	Net Surplus	\$39,000	\$2,300	\$28,000	\$2,400

Notes: Values rounded to two significant digits. Totals may appear to add incorrectly due to rounding. The Compliance Cost Savings rows include the value of product recovery.

Table 1-4 summarizes the emissions changes associated with the proposed reconsideration standards over the 2027 to 2050 period and non-monetized benefits. Emissions changes are presented for three categories: methane, VOC, and HAP.

Table 1-4 Total Projected Emissions Increases under the Proposed Reconsideration Option from 2027-2050^a

	Emissions Changes		
	Methane (million short tons)	VOC (million short tons)	HAP (million short tons)
Proposed Reconsideration	60	17	2.3
Co-Proposal	88	25	3.3
Non-Monetized Benefits			
Changes in the incidence of adverse health effects related to changes in ozone exposure resulting from increased emissions of VOC.			
Impacts on vegetation, ecosystems, and animal welfare related to changes in ozone exposure resulting from increased emissions of VOC.			
Impacts from increased emissions of methane.			
Changes in the incidence of adverse health effects related to changes in exposure to HAP resulting from increased HAP emissions.			

^a Numbers rounded to two significant digits unless otherwise noted. To convert from short tons to metric tons, multiply the short tons by 0.907.

1.4 Organization of RIA

This RIA begins with a profile of marginal wells in Section 2. The profile includes an analysis of the financial factors influencing well operating status in the baseline period prior to the additional reconsideration standards. The financial analysis is distinct from the analysis of the action's impacts, which is described throughout the remainder of the RIA.

The benefit-cost analysis summarized in this RIA reflects a nationwide engineering analysis of compliance cost and emissions changes embedded within a partial equilibrium market model of the domestic oil and natural gas sector.⁵ The proposed action enters into the model through compliance costs, which impact operators' decisions on whether to decommission producing well sites (i.e., those producing as of the 2023 "base year" of analysis) and whether to drill future projected well sites. The model and analysis are described in detail in Section 3.

Impacts of the proposed reconsideration standards are discussed throughout Sections 4 through 7. Section 4 describes the projected compliance cost, profit, and consumer surplus impacts from the quantified provisions of the proposed reconsideration standards, including the PV and EAV of the projected benefits over the 2027 to 2050 period. Section 5 considers the projected emissions increases and qualitative health and welfare impacts that are not quantified in this RIA. Section 6 describes the potential market and labor impacts associated with the proposed action. Finally, Section 7 presents the qualitative analysis of impacts from the non-quantified provisions of the proposed reconsideration standards, summarizes benefits and costs, and highlights uncertainties and limitations of the analysis.

1.5 References

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⁵ For other rule analyses such as the MATS RTR Repeal RIA (U.S. EPA, 2026), the EPA has used a model of the entire U.S. economy to estimate economy-wide social costs. The EPA is exploring whether to leverage this approach for the final rule.

2 INDUSTRY PROFILE

2.1 Introduction

This chapter describes marginal wells in the oil and natural gas industry. Marginal wells are low-producing wells. The EPA uses the definition of a marginal (or “stripper”) well that EIA adopts from the Internal Revenue Service, which is an oil well producing 15 barrels per day or less over a calendar year. For gas wells, the equivalent production rate is 90,000 cubic feet per day or less.⁶

This profile focuses on the financial factors that may affect marginal well operating status. This profile centers on marginal wells because the proposed reconsideration requirements introduce a new subcategorization of marginal well sites and associated standards for which we were able to quantify impacts. The marginal well analysis is intended to provide information on marginal well owners and operators affected by this proposed action. The financial analysis, however, does not inform the projected engineering costs and emissions impacts used in the comparison of benefits and costs of the proposed standards.

Marginal oil and gas wells are important to consider for several reasons. First, the majority of wells are marginal, comprising more than 76 percent of existing oil and natural gas wells in the United States. Second, while the majority of marginal wells are owned by large owners and operators, small owners and operators primarily own marginal oil and natural gas wells. Third, commenters have brought up marginal wells in many contexts and these comments are illustrative of the importance of marginal oil and natural gas wells to the public. Finally, states are responsible for oil and gas wells that may be orphaned by owners within their boundaries. With the large numbers of marginal oil and gas wells across the country, the financial and pollution burdens on states may be significant if some owners and operators become insolvent and their marginal wells become the responsibility of the government.

The financial analysis assumes a baseline regulatory environment along with assumptions on operating and fixed costs and estimates profits or losses of marginal wells based on different oil and natural gas production levels. In the following subsections, we examine the financial

⁶ The preamble for this rule is proposing a similar definition, where a marginal well is a well that produced less than or equal to 15 barrels of oil equivalent per day over the prior 12-month period.

condition of marginal wells, discuss the data and parameters used to implement the analysis, present results of the analysis, and conclude with a discussion of caveats and limitations of the analysis.

This section relies on industry data from the private firm Enverus that provides energy sector data and analytical services such as oil and natural gas production levels.⁷ The data used for analysis of this proposed action was accessed in October 2025 and includes 2023 production information for all wells that were completed by the end of 2023. We use 2023 as the base year to account for delays in reporting to state agencies from which much of the Enverus data is sourced.

For the Enverus oil and gas production data used in this section, the dataset is at the well- or lease-level (depending on state reporting requirements that dictate whether production is reported at the well- or lease-level) and includes the quantity of oil and gas produced at that location in 2023. For each of these well- or lease-level observations, the dataset includes the county and state that it is located in, the name of its operator, whether it is a well or lease, the number of wells at that location, and its 10-digit API unique identifier. To convert from annual production to daily production, we divide the quantity of gas and oil produced by 365 days. To convert from thousand cubic feet (MCF) to barrels, we use a conversion factor of six (i.e., 1200 mcf = 200 barrels of oil equivalent). Table 2-1 presents descriptive statistics on 2023 Enverus production data, including the top five states with the highest number of wells.

⁷ For more information on Enverus, see <https://enverus.com/>.

Table 2-1 Descriptive Statistics on Enverus Production Data, 2023

<i>All U.S. onshore oil and gas wells</i>	
# of oil and gas wells	793,557
# of operators	11,138
# of states	26
# of counties	980
<i>Top five states with the highest number of wells and the number of wells in that state</i>	
Texas	254,201
Pennsylvania	77,849
Oklahoma	64,349
Kansas	57,694
New Mexico	49,899

Source: Enverus, accessed in October 2025. Well counts are presented at the 10-digit API level. These include all oil and gas wells with non-zero production in 2023.

2.2 Descriptive Statistics on Marginal Wells

Based on our analysis of the Enverus data, we estimate that the total number of producing oil and gas wells in the United States in 2023 was 793,557, of which 341,067 were oil wells and 452,490 were natural gas wells.⁸ The amount of oil or gas produced from each well varies from less than one BOE per day to over 12,800 BOE per day.

Even though many wells are marginal, these wells produce a very small portion of total domestic production. In 2023, marginal wells comprised about 76 percent of all producing wells in the United States. There were 261,104 marginal oil wells, or 77 percent of oil wells, and 342,360 marginal natural gas wells, or 76 percent of natural gas wells. Marginal oil wells produced about 5.6 percent of the total oil production. Of these marginal oil wells, there were 221,300 wells, about 65 percent of the total oil wells, that produced less than or equal to 6 BOE per day. These oil wells accounted for about 2.6 percent of the total U.S. oil production. If marginal oil wells are further segmented, 125,367, or 37 percent of total oil wells, produced less than one BOE per day, or about 0.4 percent of the total U.S oil production. Table 2-2 presents the numbers of oil wells and production information by production rate bracket.

⁸ Enverus, accessed in October 2025. These well counts are presented at the 10-digit API level. As such these totals are lower than the well counts reported by EIA at the 14-digit level (e.g., 930,445 in 2023 (<https://www.eia.gov/petroleum/wells/>)).

Table 2-2 Distribution of U.S Marginal Oil Wells in 2023

Production rate bracket (BOE per day)^a	Number of Oil Wells	Share of Total Number of Oil Wells (%)	Production Amount (million barrels)	Share of Total Oil Production (%)
0-<1	125,367	37	15	0.35
1-<2	37,528	11	20	0.46
2-<4	38,069	11	40	0.93
4-≤6	20,328	6	36	0.85
Subtotal ≤6	221,300	65	111	2.59
6-<8	13,360	4	34	0.79
8-<10	9,879	3	32	0.75
10-<12	7,720	2	31	0.72
12-<15	8,853	3	43	1.01
Subtotal ≤15	261,104	77	252	5.63
All Oil Wells	341,067^b	100	4,295	100.00

Source: Enverus, accessed in October 2025. Well counts are presented at the 10-digit API level.

^a Production rate is defined as barrels of oil equivalent per day (BOE/d).

^b This total value represents the total number of oil wells (including wells that produce greater than 15 BOD per day), not just the number of marginal wells. So, summing the number of marginal oil wells presented above would be less than 341,067 oil wells.

Table 2-3 presents information on the number of natural gas wells and production for 2023. The patterns for natural gas wells are like those for oil wells. Marginal natural gas wells produced about 6 percent of the total natural gas production. There were 276,309 marginal natural gas wells, about 61 percent of the total natural gas wells, that produced less than or equal to 6 BOE per day. These wells accounted for about 2.5 percent of the total U.S. natural gas production. Of those wells, 136,933 wells, or 30 percent of total natural gas wells, produced less than one BOE per day, or about 0.28 percent of the total U.S. natural gas production.

Table 2-3 Distribution of U.S Marginal Natural Gas Wells in 2023

Production rate bracket (BOE/d)^a	Number of Natural Gas Wells	Share of Total Number of Natural Gas Wells (%)	Production Amount (million BOE)	Share of Total Natural Gas Production (%)
0–<1	136,933	30	18	0.28
1–<2	49,408	11	26	0.39
2–<4	55,928	12	59	0.89
4–≤6	34,036	8	61	0.92
Subtotal ≤6	276,309	61	165	2.48
6–<8	22,471	5	57	0.85
8–<10	16,344	4	53	0.80
10–<12	12,666	3	275	0.76
12–<15	14,573	3	71	1.07
Subtotal ≤15	342,360	76	397	5.97
All Gas Wells	452,490	100	6,661	100.00

Source: Enverus accessed in October 2025. Well counts are presented at the 10-digit API level.

^a Production rate is defined as barrels of oil equivalent per day (BOE/d).

While marginal wells account for a relatively small percentage of domestic production of oil and natural gas, recent studies suggest that their contribution to methane emissions from oil and natural gas production is much greater. For example, in a study funded by DOE’s National Energy Technology Laboratory (DOE-NETL), Bowers (2022) estimates that marginal natural gas and oil wells account for 59 percent and 37 percent of cumulative methane emissions from oil and natural gas production, respectively, and roughly half of cumulative methane emissions from combined oil and natural gas production. Similarly, Omara et al. (2022) estimate that low production well sites account for roughly half (95 percent confidence interval: 37–75 percent) of all oil and natural gas well site methane emissions. In the analysis performed for the March 2024 Final Rule, we estimated that marginal wells account for 47–53 percent of well site methane emissions for the emissions sources addressed in that action.

2.3 Ownership of Marginal Wells

In 2023, the oil and gas wells described in the previous section were owned and operated by 11,148 unique operators. Of those, 10,920 operators (98 percent) own at least one marginal well. When further segmenting marginal wells by production size, 8,714 operators own at least one marginal well that produces between 0 – <1 BOE/d; 6,527 operators own at least one marginal well that produces between 1 – ≤6 BOE/d; and 3,156 operators own at least one marginal well that produces between 6 – 15 BOE/d.

Table 2-3 and Table 2-4 present a summary of well and marginal well ownership. Most marginal wells are owned by larger firms that also operate many other wells. For example, the 127 firms that own 1,000 or more oil and gas wells operate 51.3 percent of all marginal wells in the U.S., accounting for 67.3 percent of all marginal well production. The 903 firms that own 100 or more oil and gas wells own 80.6 percent of all marginal wells in the U.S. and account for 88.3 percent of all marginal well production. At the same time, most firms are small operators. Over 65 percent of firms (7,320 firms) own ten or fewer oil and gas wells. These firms in total own 3.2 percent of all marginal wells in the U.S. and account for 1.9 percent of all marginal well production. As shown in Table 2-4, these firms typically own marginal wells; for the average firm with 10 or fewer total wells, 86 percent of them are marginal wells.

Table 2-4 Summary of U.S. Oil and Natural Gas Well Ownership in 2023

Firm Size Category	Number of firms	Share of Total Number of Wells (%)	Share of Total U.S. Production (%)	Share of all MWs (%)	Share of all U.S. MW Production (%)	MW share of firm's total wells (%)
Top 50 firms by total #wells	50	43.9	64.8	38.1	52.9	9.8 – 100
Top 50 firms by total production	50	36.3	79.1	26.3	39.5	0 – 92.6
Firms w/1000+ total wells	127	57.6	80.7	51.3	67.3	4.9 – 100
Firms w/100+ total wells	903	83.7	95.0	80.6	88.3	0 – 100
Firms w/ ≤10 total wells	7320	2.7	0.4	3.2	1.9	0 – 100
Firms w/ ≤2 total wells	4462	0.7	0.1	0.8	0.5	0-100%

Source: Enverus data accessed in October 2025. Well counts used for the information in this table are at the 10-digit API level. Production data is used in this table is in barrels of oil equivalent per day (BOE/d). Firm counts are based on the number of unique “Operator Company Name” entries.

Table 2-5 Summary of U.S. Oil and Natural Gas Well Ownership by Smaller Firms (10 Wells or Less) in 2023

	Min	5 th	Mean	Median	95 th	Max
Number of total wells owned	1	1	2.9	2	9	10
Number of MWs owned	0	0	2.4	1	8	10
MW share of firm's total wells (%)	0	0	86	100	100	100

Source: Enverus data accessed in October 2025. Well counts used for the information in this table are at the 10-digit API level. Production data is used in this table is in barrels of oil equivalent per day (BOE/d). Firm counts are based on the number of unique “Operator Company Name” entries.

2.4 Marginal Wells Financial Analysis Model

The estimated annual net profit is calculated for average marginal wells in each production bracket reported by Enverus for 2023. We focus on an estimated annual net profit because oil and natural gas production from a particular well naturally declines over time. Accordingly, the maximum profit for the average well is very likely to be from its first year of operation as the remaining production life is limited and production levels will be lowest towards the end of a production life of a well. To capture this decline in profits over the production life of an average well, profits are calculated by incorporating a production decline parameter in PV factor for revenues for each production bracket.⁹ Note that the modeling used for the main benefit-cost analysis performed for this proposed action represents additional economic considerations that factor in decommissioning decisions; see Section 3.2.1 for more information.

The parameter values presented in Table 2-6 are obtained from a variety of sources. The economic life (15 years) is the same as the assumption used in a similar analysis from the Michigan Oil and Gas Association (MOGA) comments on the December 2022 Proposal. The landowner royalty percentage is the average of the assumption used in the MOGA analysis (20 percent) and the assumption from an analysis in Riverside Energy comments on the November 2021 Proposal (12.5 percent). The severance tax rate (5 percent) matches the assumptions from the MOGA analysis and an industry-sponsored (Joint Industry Working Group, or JIWG) analysis performed to assess proposed revisions to Colorado regulations.¹⁰ The decline rate (5 percent) matches the assumption from the MOGA analysis.

The operating cost assumptions are subject to considerable uncertainty. We elected to assume that all operating costs are fixed annual costs that don't depend on production levels. This assumption matches the JIWG analysis and is standard in academic literature on valuing natural resource properties in dynamic stochastic analysis models.^{11,12} It differs from the

⁹ Net profit results for each average well are based on an average well's baseline production level in 2023 (based on Enverus data), not the production bracket a particular average well may be projected to occupy later in its assumed economic useful life.

¹⁰ See Exhibit A at <https://www.sos.state.co.us/CCR/Upload/AGORequest/RegulatoryAnalysisAttachment2013-01215.PDF>.

¹¹ See: Clarke and Reed (1990), Smith and McCardle (1998), and Enders et al. (2010).

¹² We don't have a high degree of confidence in the assumption and a discussion is provided in the caveats and limitations section. As we discuss in the paragraph, there are published papers and industry analyses that support either a fixed or variable approach for operating costs. We chose to use an approach that matches the assumptions in the literature studies upon which the decommissioning model from Section 3.2.1 is based.

assumptions in the Riverside Energy and MOGA analyses, as well as at least one other academic study on the decommissioning decision of marginal wells, which all represent costs as either variable, or having both fixed and variable cost components.¹³ To maintain consistency with our modeling approach (described in Section 3.2.1), we implement the fixed cost-only assumption. To estimate the level of the costs, we take the average of two literature studies that analyze marginal well economics for two companies that specialize in the operation of marginal wells, EQT Corp. and Diversified Energy Company. For a study of a well in EQT's portfolio, Enders et al. (2010) used representative baseline maintenance costs of \$3,852 (with additional costs for different operation technologies). Weber et al. (2021) leveraged publicly available information from Diversified to estimate an annual operating cost of \$2,061. Taking the average yields ~\$3,000 of annual operating cost, which is what we use for our analysis.

This baseline financial analysis estimates profits in the absence of any new regulation affecting these marginal wells. Natural gas wells primarily produce natural gas but there is also a relatively small amount of oil produced. Similarly, oil wells also co-produce some natural gas. The revenue for marginal wells is calculated by multiplying gas and oil production by their respective commodity prices and summing, then multiplying by a PV factor with a parameter reflecting the decline in the production level over time:

$$PV_Factor_{Revenue} = \frac{(1+r)^n - (1 - Decline_Rate)^n}{(r + Decline_Rate) * (1+r)^n} \quad \text{Eq. 2-1}$$

where r is the discount rate, n is the time horizon of analysis, and $Decline_Rate$ is the parameter for the production level decline rate of wells. To estimate the annual value, the expression is multiplied by the EAV factor based on the discount rate and analysis time horizon:

$$EAV_Factor = \frac{r * (1+r)^n}{(1+r)^n - 1}. \quad \text{Eq. 2-2}$$

The resulting annualized equivalent revenue is represented by the following equation:

$$Annualized_Equivalent_Revenue = (Oil_{Price} * Oil_{Production} + Gas_{Price} * Gas_{Production}) * PV_Factor_{Revenue} * EAV_Factor, \quad \text{Eq. 2-3}$$

¹³ See: Weber et al. (2021).

where $Oil_{Production}$ and $Gas_{Production}$ are the respective annual production levels for each production bracket reported by Enverus for 2023. Oil production levels for each bracket were calculated based on the average production in barrels per day for wells of that given well type (either oil or gas wells). Similarly, gas production levels for each bracket were calculated based on the average gas production in thousand cubic feet (Mcf) per day for wells of that well type. Oil_{Price} and Gas_{Price} are the respective annual prices for each price scenario for oil and natural gas reported by the EIA. Annual operating costs include fixed operating and maintenance costs, which are multiplied by a PV factor for costs:

$$PV_Factor_{Costs} = \frac{(1+r)^n - 1}{r * (1+r)^n}, \quad \text{Eq. 2-4}$$

where there is no additional decline parameter like in the PV for revenues. To estimate the annual operating costs, the expression is multiplied by the EAV factor:

$$\begin{aligned} Annual_Operating_Cost = & ((Royalty_Tax + Severance_Tax) * \\ & (Oil_{Price} * Oil_{Production} + Gas_{Price} * Gas_{Production}) * \\ & PV_Factor_{Revenue} + (Fixed_O\&M) * PV_Factor_{Costs}) * \\ & EAV_Factor \end{aligned} \quad \text{Eq. 2-5}$$

where $Royalty_Tax$ and $Severance_Tax$ are parameters for taxes that are tied to the production level of wells, and $Fixed_O\&M$ is the parameter for annual fixed operating and maintenance cost of the average well. Annual operating cost is subtracted from annualized equivalent revenue to obtain the annualized equivalent of the net profit:

$$Profit = Annualized_Equivalent_Revenue - Annual_Operating_Cost \quad \text{Eq. 2-6}$$

Table 2-6 Marginal Well Financial Analysis Parameters

Parameter	Description	Value
<i>n</i>	Useful economic life of a marginal well (years)	15
<i>r</i>	Discount rate	0.07
<i>Royalty_Tax</i>	Landowner royalty ^a	16.25%
<i>Severance_Tax</i>	Severance tax ^b	5%
<i>Fixed_O&M</i>	Fixed operating and maintenance cost (\$/well/year) ^{a,c}	\$3,000
<i>Decline_Rate</i>	Production level decline each year ^d	5%

^a Source: Average of the royalty rates provided in the Riverside Energy comments on the November 2021 Proposal (EPA-HQ-OAR-2021-0317-0411) and the Michigan Oil and Gas Association comments on December 2022 Proposal (EPA-HQ-OAR-2021-0317-2257).

^b Source: Michigan Oil and Gas Association comments on December 2022 Proposal (EPA-HQ-OAR-2021-0317-2257).

^c The analysis assumes that variable costs are zero.

^d Source: Source: Michigan Oil and Gas Association comments on December 2022 Proposal (EPA-HQ-OAR-2021-0317-2257).

2.5 Results

The results of the financial analysis are presented in Table 2-7, Table 2-8, and Table 2-9. The tables present the profit estimation for the reference (or mid-range)¹⁴ price of oil and natural gas projected for 2029 from the EIA, as well as the projected low and high prices for the same year. Note: for the purpose of this analysis, the *low* supply case corresponds to the *high*-range price scenario and *high* supply case corresponds to the *low*-range price scenario.¹⁵ In the mid-range price scenario, the oil price is assumed to be \$90.57 per barrel, and the natural gas price is assumed to be \$2.89 per MMBtu. In each table, the Annualized Equivalent Net Profit is the annualized equivalent profit that, if incurred each year, would produce the same net present value over the analytical timeframe for an average marginal well in 2023 for a particular production bracket before any additional regulatory costs are considered. In addition to presenting the

¹⁴ We use the term “reference” to describe the scenario that is calibrated to the EIA 2025 AEO. The preamble for this rule uses the term “mid-range” to describe the 2025 AEO Reference Case scenario prices for both crude oil (Lower 48 Average Wellhead Price) and the natural gas (Henry Hub Spot Price). For the purposes of the analysis in this section, the reference price scenario is equivalent to the “mid-range” price scenario and considered our main scenario.

¹⁵ Projected low and high prices for oil and gas (under high and low supply, respectively) are from AEO2025 and are referred to as “low-range” and “high-range” price scenarios in the preamble for the rule. The low-range and high-range cases include data from the “High-” and “Low-” “Oil and Gas Supply” scenarios for crude oil and natural gas to generate higher and lower commodity prices. Crude oil prices are from the lower 48 average wellhead price; natural gas prices are from the Henry Hub spot price. These alternative scenarios serve as sensitivity analysis. The EPA chose to use the projected pricing under alternative oil and gas supply cases, rather than the AEO2025 High/Low Oil Price cases, because they result in a larger range of projected oil and natural gas prices and we believe this broader range provides a more robust sensitivity for evaluating marginal well profitability rather than focusing oil-specific metric.

annualized equivalent net profits for the average oil and gas wells with production less than or equal to 15 BOE per day (listed in the last row of the table), the annualized equivalent net profits are also disaggregated into smaller production brackets to give a fuller picture of the annualized equivalent net profits of marginal oil and gas wells. This highlights that, while comprising a smaller percentage of the overall number of marginal wells, the higher producing marginal wells generate comparatively more profits, thereby increasing the average profits across all marginal wells. This can be seen when comparing the annualized equivalent net profit for average marginal oil and gas wells in Table 2-7, about \$45,000 and \$12,000, respectively, to each disaggregated production bracket.

Focusing on the mid-range price scenario in Table 2-7, marginal oil wells are profitable at every production level. At the lowest production bracket, 0–<1 BOE per day, the average oil well earns a positive annualized equivalent net profit of about \$3,300. At the next highest production level, 1–<2 BOE per day, the annualized equivalent net profits for the average oil well are estimated to be about \$25,000. At the highest production level for marginal wells, 12–15 BOE per day, the annualized equivalent net profits are more than about \$230,000.

Marginal gas wells can be unprofitable before the addition of any regulatory costs and have lower profits than marginal oil wells in corresponding production brackets. Again, looking at the mid-range price scenario in Table 2-7, the average gas well in the 0–<1 production bracket is estimated to be unprofitable with about \$1,300 annual loss. Annualized equivalent net profits are positive for 1–<2 BOE per day at about \$3,500 with the highest level of annualized equivalent net profits also occurring at the 12–15 BOE per day production bracket at over about \$65,000.

As a sensitivity check on the mid-range price scenario, low and high price scenarios are also presented. Table 2-8 presents the annualized equivalent net profits for the low oil and natural gas prices. In the low-supply, price scenario the oil price is assumed to be \$63.24 per barrel and the natural gas price is assumed to be \$2.21 per MMBtu. Annualized equivalent net profits for marginal oil wells and natural gas wells behave similarly to the mid-range price scenario; marginal oil wells are profitable at each production bracket and marginal natural gas wells are profitable in all but the 0–<1 BOE per day bracket where annualized equivalent net profit is negative.

Table 2-9 contains the annualized equivalent net profit estimates for the high price scenario. In the high supply, price scenario the oil price is assumed to be \$113.47 per barrel and the natural gas price is assumed to be \$4.94 per MMBtu. While the annualized equivalent net profits for marginal oil wells behave similarly to the average and the low-price scenarios, the marginal natural gas wells are now profitable at each production bracket—with the positive correlation between profitability and production level holding. While not directly comparable to the regional study by Weber et al. (2021), this result is in general agreement with their conclusion that the lowest producing natural gas wells are less likely to be economical.

Table 2-7 Annualized Equivalent Revenues, Costs, and Profits for 2023 Marginal Wells: Mid-Range Oil and Natural Gas Reference Case (2024\$)^a

Production rate bracket (BOE per day)	Oil Wells			Gas Wells		
	Annual Gross Revenue	Annual Operating Cost	Annualized Equivalent Net Profit	Annual Gross Revenue	Annual Operating Cost	Annualized Equivalent Net Profit
0–<1	\$8,000	\$4,700	\$3,300	\$2,100	\$3,500	-\$1,300
1–<2	\$35,000	\$10,000	\$25,000	\$8,300	\$4,800	\$3,500
2–<4	\$68,000	\$18,000	\$51,000	\$17,000	\$6,600	\$10,000
4–≤6	\$110,000	\$27,000	\$87,000	\$29,000	\$9,200	\$20,000
Subtotal ≤6^b	\$33,000	\$10,000	\$23,000	\$9,600	\$5,000	\$4,500
6–<8	\$160,000	\$37,000	\$120,000	\$43,000	\$12,000	\$31,000
8–10	\$200,000	\$46,000	\$160,000	\$56,000	\$15,000	\$41,000
10–<12	\$250,000	\$56,000	\$190,000	\$69,000	\$18,000	\$51,000
12–15	\$300,000	\$67,000	\$230,000	\$86,000	\$21,000	\$65,000
Subtotal ≤15^c	\$61,000	\$16,000	\$45,000	\$19,000	\$7,100	\$12,000

Note: Values rounded to two significant digits. Totals may appear to add incorrectly due to rounding. The table header for “annual gross revenue” refers to “annualized equivalent revenue.” Annualized equivalent financial estimates are for marginal oil and natural gas wells and use weighted average monthly price of oil and natural gas. Annual Gross Revenue is estimated using Equation 2-3. Annual operating cost is calculated with Equation 2-5, using parameters from Table 2-6. Annualized Equivalent Net Profit is calculated from Equation 2-6.

^a Source: EIA, AEO2025 National Energy Modeling System. Table 14. Oil and Gas Supply. The prices for the projected 2029 reference case is \$90.57/bbl for oil and \$2.89/MMBtu for natural gas. See <https://www.eia.gov/outlooks/aeo/data/browser/>.

^b Subtotals are averages for oil and natural gas wells with 6 BOE per day or less.

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

Table 2-8 Annualized Equivalent Revenues, Costs, and Profits for 2023 Marginal Wells: High Oil and Natural Gas Supply Case (2024\$)^a

Production rate bracket (BOE per day)	Oil Wells			Gas Wells		
	Annual Gross Revenue	Annual Operating Cost	Annualized Equivalent Net Profit	Annual Gross Revenue	Annual Operating Cost	Annualized Equivalent Net Profit
0–<1	\$5,600	\$4,200	\$1,400	\$1,600	\$3,300	- \$1,700
1–<2	\$24,000	\$8,200	\$16,000	\$6,200	\$4,300	\$1,900
2–<4	\$48,000	\$13,000	\$35,000	\$13,000	\$5,700	\$7,000
4–≤6	\$80,000	\$20,000	\$60,000	\$22,000	\$7,700	\$14,000
Subtotal ≤6^b	\$23,000	\$7,900	\$15,000	\$7,200	\$4,500	\$2,700
6–<8	\$110,000	\$27,000	\$85,000	\$32,000	\$9,800	\$22,000
8–10	\$140,000	\$33,000	\$110,000	\$42,000	\$12,000	\$30,000
10–<12	\$170,000	\$40,000	\$130,000	\$52,000	\$14,000	\$38,000
12–15	\$210,000	\$48,000	\$160,000	\$64,000	\$17,000	\$47,000
Subtotal ≤15^c	\$43,000	\$12,000	\$31,000	\$15,000	\$6,100	\$8,500

Note: Values rounded to two significant digits. Totals may appear to add incorrectly due to rounding. The table header for “annual gross revenue” refers to “annualized equivalent revenue.” Annualized equivalent financial estimates are for marginal oil and natural gas wells and use weighted average monthly price of oil and natural gas. Annual Gross Revenue is estimated using Equation 2-3. Annual operating cost is calculated with Equation 2-5, using parameters from Table 2-6. Annualized Equivalent Net Profit is calculated from Equation 2-6.

^a Source: EIA, AEO2025 National Energy Modeling System. Table 14. Oil and Gas Supply. The prices for the projected 2029 High Oil and Gas Supply case is \$63.24/bbl for oil and \$2.21/MMBtu for natural gas (note: The “High” case used in the analysis is labeled as “Low Oil and Gas Supply” in AEO2025 but EPA staff believe the data source is mislabeled and should be considered the *High* Oil and Gas Supply). See <https://www.eia.gov/outlooks/aeo/data/browser/>.

^b Subtotals are averages for oil and natural gas wells with 6 BOE per day or less.

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

Table 2-9 Annualized Equivalent Revenues, Costs, and Profits for 2023 Marginal Wells: Low Oil and Natural Gas Supply Case (2024\$)^a

Production rate bracket (BOE per day)	Oil Wells			Gas Wells		
	Annual Gross Revenue	Annual Operating Cost	Annualized Equivalent Net Profit	Annual Gross Revenue	Annual Operating Cost	Annualized Equivalent Net Profit
0–<1	\$10,000	\$5,100	\$4,900	\$3,500	\$3,700	-\$260
1–<2	\$44,000	\$12,000	\$32,000	\$14,000	\$5,900	\$7,700
2–<4	\$86,000	\$21,000	\$65,000	\$28,000	\$8,900	\$19,000
4–<6	\$140,000	\$34,000	\$110,000	\$47,000	\$13,000	\$34,000
Subtotal ≤6^b	\$41,000	\$12,000	\$29,000	\$16,000	\$6,300	\$9,300
6–<8	\$200,000	\$46,000	\$160,000	\$69,000	\$18,000	\$51,000
8–10	\$260,000	\$58,000	\$200,000	\$89,000	\$22,000	\$67,000
10–<12	\$310,000	\$70,000	\$240,000	\$110,000	\$26,000	\$84,000
12–15	\$380,000	\$84,000	\$300,000	\$140,000	\$32,000	\$100,000
Subtotal ≤15^c	\$77,000	\$19,000	\$58,000	\$31,000	\$9,600	\$22,000

Note: Values rounded to two significant digits. Totals may appear to add incorrectly due to rounding. The table header for “annual gross revenue” refers to “annualized equivalent revenue.” Annualized Equivalent financial estimates are for marginal oil and natural gas wells and use weighted average monthly price of oil and natural gas. Annual Gross Revenue is estimated using Equation 2-3. Annual operating cost is calculated with Equation 2-5, using parameters from Table 2-6. Annualized Equivalent Net Profit is calculated from Equation 2-6.

^a Source: EIA, AEO2025 National Energy Modeling System. Table 14. Oil and Gas Supply. The prices for the projected 2029 Low Oil and Gas Supply case is \$113.47/bbl for L48 average wellhead oil price and \$4.94/MMBtu for natural gas at Henry Hub (note: The “Low” case used in the analysis is labeled as “*High* Oil and Gas Supply” in AEO2025 but EPA staff believe the data source is mislabeled and should be considered the *Low* Oil and Gas Supply). See <https://www.eia.gov/outlooks/aeo/data/browser/>.

^b Subtotals are averages for oil and natural gas wells with 6 BOE per day or less.

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

2.6 Marginal Wells Financial Analysis Caveats and Limitations

The goal of this analysis is to evaluate the profitability of marginal wells under a certain set of assumptions. While we are not able to evaluate other considerations that may affect the profitability of marginal wells due to data gaps and other challenges, we discuss these caveats and limitations in this section.

Marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons. A simple break-even analysis that only evaluates well profitability in a single time-period can help shed light on whether the well has a higher likelihood of shutting-in, but it doesn't capture the full decision-making process. That is, a single period of losses most likely will not cause a firm to shut-in and plug a well but larger, sustained

losses over many years could. Thus, it seems that costs must be much larger than any benefits of delay, including expected future revenue from production, before a well is realistically at risk for being shut-in and plugged. The uncertainty surrounding future oil and gas production, commodity prices, tax treatments, and regulatory regimes also contributes to the difficulty in predicting when or if an operator decides to shut-in and plug any given well.

Further, because regulatory costs also depend on types of equipment used at well sites, the full impact of regulation on the financial status of marginal well owners cannot be determined. The age, location, and what is produced from each marginal well also contribute to differences in baseline regulatory costs. This adds heterogeneity to the regulatory cost burdens on owners and adds complexity to estimating impacts. Additionally, accounting practices that enable the delay of plugging costs, tax subsidies, low state bonding requirements, a market for marginal wells, and useful economic life assumptions may impact owner/operators' decision on whether to shut-in and plug a well. These additional considerations were not able to be empirically evaluated and make it extremely difficult to determine the full impact of regulation on the financial status of marginal well owners.

Below, we summarize these key sources of uncertainty and limitations. We also attempt to offer some insight into how inaccuracies in our assumptions might bias our estimates.

Plugging costs: The costs of plugging can vary widely depending on well characteristics and by state. Estimates range from less than \$1,000 to over \$1 million, with an average of about \$75,000 per well (Raimi et al., 2021). It has been reported that in some cases those costs can be reduced to around \$25,000, although it is not clear if the methods used could be more broadly applied.¹⁶ Through accounting practices and discounting, the costs associated with plugging wells can be delayed far into the future. This delay effectively reduces the present value of costs for the owners and operators and increases the firm's profitability in the short run. Therefore, by changing the financial break-even point for when to close the low producing well, owner/operators can extend the well's production period and push the decision to shut-in the well further into the future. Wells that would otherwise be left in a low-producing or idled state for

¹⁶ See: <https://www.bloomberg.com/features/diversified-energy-natural-gas-wells-methane-leaks-2021/>.

many years because the costs of plugging are too high can benefit from federal subsidies to reduce or completely cover the costs of plugging.¹⁷

Severance Taxes: Our analysis assumes a severance tax rate of five percent in all areas of the country, but in reality, there is variation in this tax across states and some have various exemptions for lower-producing wells. For example, Colorado has a graduated tax structure reaching up to five percent based on gross income, while also effectively lowering their average rates through ad valorem tax credit over the last decade. Colorado also provides a tax exemption for stripper wells—defined as those producing 15 barrels or less of oil, or 90,000 cubic feet of gas per day—from state severance taxes.¹⁸

Tax Subsidies: Federal and state tax-credits are available for owners and operators of marginal oil and gas wells when prices are low. These tax credits reduce the cost of owning marginal wells.¹⁹ At the federal level, wells that produce no more than 25 BOE per day can qualify for the credit. With no limit on the number of wells that can qualify, each well can receive a tax credit for up to 1,905 BOE of total production per year. The credit value for marginal gas wells is based on the reference natural gas price published by the Internal Revenue Service (IRS); in 2021, the maximum value was \$4,336 per well. Starting in 2025, the value of the credit increased to \$0.79 per mcf.²⁰ Any unused portion of the tax credit can either be carried back five years or forward 20 years. The current tax credit applies when the reference price of natural gas is below \$2 per Mcf.²¹ For marginal oil wells, the reference price is \$15 per barrel of oil.²² Since the amount of the credit is phased out when oil prices are greater than the reference price, high oil prices relative to the reference price means the marginal oil credit has not been available in recent years. Another federal tax incentive that our analysis does not account for is the section 611/613 percentage depletion tax deduction, which lowers the tax burden for independent oil and gas producers and can vary in magnitude year to year. Currently, percentage

¹⁷ Through the Methane Emissions Reduction Program, the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), and DOE's National Energy Technology Laboratory (NETL) are partnering to provide up to \$1.36 billion in financial and technical assistance through an interagency agreement to improve methane emissions monitoring, detection, measurement, and quantification and also reduce methane and other GHG emissions from the oil and natural gas sector.

¹⁸ See: https://content.leg.colorado.gov/sites/default/files/r25-328_effective_severance_tax_rates-accessible_0.pdf.

¹⁹ See: <https://crsreports.congress.gov/product/pdf/IF/IF11528>.

²⁰ See <https://www.irs.gov/instructions/i8904>.

²¹ See: <https://www.irs.gov/pub/irs-irbs/irb23-23.pdf>.

²² See: https://www.irs.gov/irb/2023-26_IRB.

depletion is calculated by applying a 15% reduction to a marginal well property's taxable gross income (<https://nswa.us/percentage-depletion/>). We are researching the details of this tax credit and exploring whether and how to reflect it in our analysis.

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

Market for marginal wells: There is a market for buying and selling marginal wells, and it is possible that not only could current market participants increase their holdings of marginal wells, but new participants could also enter the market. For example, Diversified Energy, headquartered in Birmingham, Alabama, is reported to be the largest owner of oil and natural gas wells in the country, with a large percentage being marginal wells.²³ Diversified Energy describes its business strategy as acquiring uneconomic wells that are low-cost, low decline wells that are expected to continue producing far into the future. Diversified owns wells throughout Appalachia and has also begun purchasing wells in Louisiana and Texas. It is conceivable that as more marginal wells become uneconomic through market conditions, regulatory costs, and declining production, firms that specialize in cost control and maintenance of existing wells will find it advantageous to buy these low-producing wells from the current owners.

Useful economic life of a marginal well: Equivalent annualized net profits for marginal wells are estimated using a parameter for useful economic life of an average marginal well operating as of 2023. The useful economic life of an asset can generally be defined as the average number of years an asset remains cost-effective to operate, after which an operator may be indifferent to or prefer decommissioning a well. However, there is no robust estimate available for the average marginal well. Marginal wells may operate for decades and have economic and resources factors that affect a particular well's lifespan such as age, size, location—as well as other financial factors mentioned earlier in this section (Omara, 2022). Therefore, the EPA is assuming a 15-year useful economic life for the marginal well financial

²³ See: <https://ohiorivervalleyinstitute.org/wp-content/uploads/2022/04/Diversified-Energy-Report-FINAL-1.pdf>.

analysis.²⁴ A higher assumed useful life would lower the estimates of equivalent annualized profit; similarly, if we assume a lower useful economic life, the estimates of equivalent annualized profit would be higher.

2.7 References

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²⁴ While this assumed useful economic life is being used for the purpose of conducting the marginal well financial analysis, the partial equilibrium modeling used for the analysis of quantified economic surplus uses additional equipment life assumptions corresponding to model equipment assignment.

3 METHODOLOGY

We conduct the impacts analysis for the proposed action using a simple dynamic partial equilibrium model of crude oil (“oil”) and dry natural gas (“gas”) production and consumption in the United States.²⁵ The model solves for equilibrium state-level onshore supply and nationwide demand of oil and gas production, with endogenous treatment of international trade, at an annual resolution through 2050. Within domestic onshore supply, endogenous choices include decisions over whether to continue operating or permanently decommission sites that already exist in our base year, the levels of production from newly drilled wells in each year, and quantities of exports. Domestic consumers make endogenous decisions over total demand for oil and gas and the composition of domestically produced and imported commodities that meet that demand. On the other hand, site-level production levels are assumed to follow exogenous trajectories outside of the drilling and decommissioning decisions. Outputs from the model include operating well and site counts from the sites existing in the base year; market-clearing price, consumption, and production levels; producer surplus for domestic producers; and consumer surplus for the domestic market.

The model is parameterized and calibrated based on data and projections from a variety of sources, most notably the EIA AEO2025 Reference Case and Enverus’ Drillinginfo and Prism platforms.²⁶ We use the term “reference” to describe the scenario that is calibrated to the AEO to avoid confusion with the “baseline” scenario, which is the regulatory baseline used for the impacts analysis. Due to significant uncertainties in several of the model’s key parameters, scenarios are intended to be simulated for a set of Monte Carlo draws, with results presented as the average over the distribution of outcomes. Below, we discuss the model construction and calibration and how regulatory policy is captured. Additional modeling details are presented in the Technical Support Document: Crude Oil and Natural Gas Partial Equilibrium Model Documentation, available in the docket.²⁷

²⁵ Currently, the model only accounts for dry gas production, or the quantity of gas after natural gas liquids have been removed.

²⁶ The latest AEO, along with links to previous versions, can be found at <https://www.eia.gov/outlooks/aeo/>. More information about Enverus can be found at <https://www.enverus.com/>. DrillingInfo and Prism are applications created and maintained by Enverus that provide data visualization and export tools. The data accessible in each is largely overlapping, but there are a few fields that are only available in one or the other.

²⁷ The modeling technical support document provides an overview of the methodology is available in the docket here: docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2025-0163>.

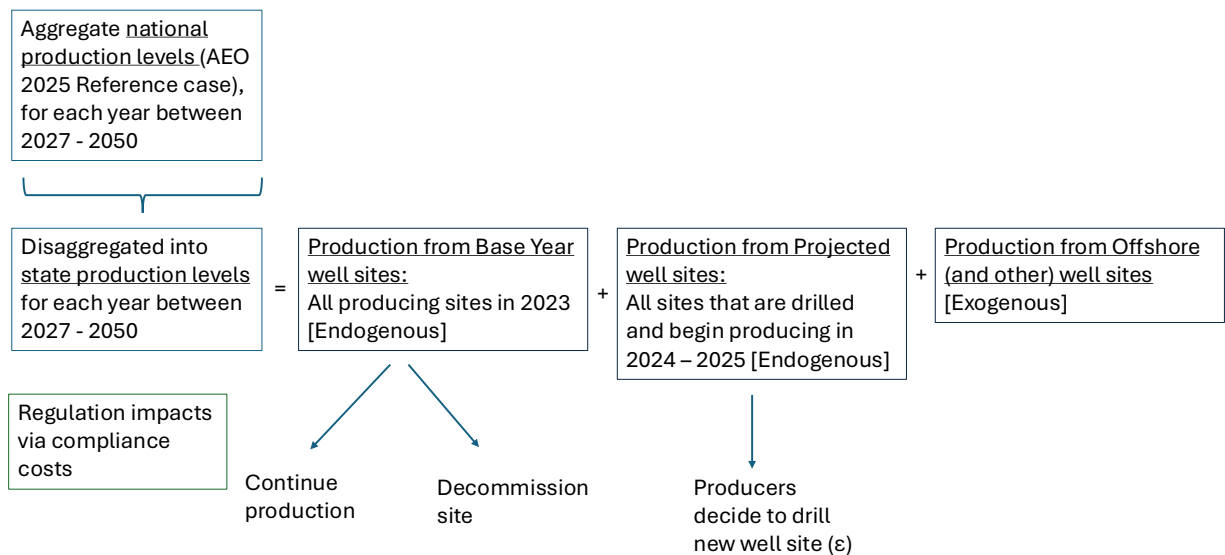
3.1 Demand

The model represents domestic U.S. and foreign demand for domestic U.S. production of oil and gas. Domestic demand is captured by a series of demand functions for each year and commodity. In this sense, the oil and gas markets are treated as separable from the perspective of consumers. Beneath top level domestic demand for each commodity, the model employs a trade specification that allows domestic consumers to substitute between domestically produced and imported commodities. Foreign demand for domestic production is represented by a series of demand functions for each year and commodity.

Calibration of the demand functions is based on AEO projections and elasticity estimates from literature. Reference levels of domestic demand are derived by adding projected levels of domestic production to net imports of each commodity. Reference commodity prices for the domestic market are the projected West Texas Intermediate (WTI) and Henry Hub prices for oil and gas, respectively. Reference commodity prices for imports are the projected import and Henry Hub prices for oil and gas, respectively. Reference export levels are taken directly from AEO projections, with the reference prices for exports assumed to be same as the reference prices for the domestic market (WTI and Henry Hub). The composite bundle price for the CES demand function is normalized to one. The elasticity estimates are based on the same sources of information as used in the analysis of EPA's Waste Emissions Charge (WEC).²⁸ We use the long-term elasticities described in that analysis for foreign supply and demand, consumer substitution between domestic and foreign supply, and overall consumer demand for commodities. Our oil and gas supply elasticities draw directly from Newell and Prest (2019a) and Newell et al. (2019b).

²⁸ For more details on the model estimates of elasticity parameters, see Section 5.2.1 of the November 2024 Waste Emissions Change Final Rule RIA available here: https://www.epa.gov/system/files/documents/2024-11/wec-ria-final_11-2024.pdf.

3.2 Supply



In the model, domestic supply can either supply the domestic market or the export market. Sources of domestic supply are partitioned into three components. First, *base year well sites* represent production sites that were captured by the Enverus data pull described in Section 2.1. Second, *projected well sites* represent production sites projected to start producing in years after the base year. Finally, exogenous sources of supply include offshore production and production from well sites lacking sufficiently detailed data from Enverus.²⁹ The data, calibration, and modeling approach to base year and projected well sites are discussed in more detail below.

The model is constructed so that, in the absence of any requirements under the NSPS or EG, aggregate national production levels will nearly match the AEO2025 Reference Case for all projected years.³⁰ This assumes that the AEO2025 projection methodology does not incorporate requirements or expected requirements for any NSPS or EG in the OOOO series, which we believe is a reasonable assumption as they are not explicitly mentioned in the Hydrocarbon

²⁹ This includes production from the following states: Arizona, Idaho, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, and Virginia. Those states account for a small percentage of overall U.S. domestic production of both oil and natural gas.

³⁰ The aggregate reference production levels do not exactly match the AEO2025 levels because of state-level adjustments that we describe in Section 3.2 of the model methodology TSD.

Supply Module (HSM)—formerly the Oil and Gas Supply Module—documentation. Historical data from EIA is used to further disaggregate reference production levels to the state level. Projected state-level production is further disaggregated into production from base year well sites, projected future well sites, and exogenous sources where specific data is lacking.

To allocate reference national production to the state level, we start with projections of production of both oil and gas from the AEO2025 Reference Case at the HSM region level for the continental U.S., and separately for Alaska (including offshore in both cases).³¹ The HSM regions largely adhere to state boundaries, except for New Mexico, whose production maps into two regions, and Texas, whose production maps into three regions. To disaggregate the projected production, we use historical production data from EIA for the base year (2023) at the state level and assume the proportion of a state’s production within an HSM region stays fixed over the model horizon. For New Mexico and Texas, we incorporate an additional step in which we allocate the historical production in those states to HSM regions based on base year well-level production data from Enverus. We then apply the proportional allocations to states, summing up the allocations to the state level for New Mexico and Texas.

3.2.1 Base Year Well Sites

We use the term “base year well sites” to refer to all domestic well sites that were producing oil or natural gas in 2023. In the model, future production from these base year well sites is endogenously determined by operators deciding whether to continue operating or permanently decommission sites. They choose whichever scenario maximizes the value of each site, subject to assumptions about future prices and production levels. Base year site production exogenously evolves according to modified hyperbolic decline curves, in which production begins by following a hyperbolic decline path and then transitions to exponential decline at a fixed terminal rate; see Figure 3-1 for a stylized example of this type of decline curve. For our analysis, we assume the transition to exponential decline occurs when either the effective decline rate reaches five percent or site-level production falls below 6 BOE per day. For periods in which production follows a hyperbolic decline path, operators are assumed to continue

³¹ See page 29 of the Hydrocarbon Supply Module (HSM) of the National Energy Modeling System (NEMS) 2026 model documentation. Since no model documentation was published for HSM in AEO2025, the AEO2026 model documentation is most relevant and available at: https://www.eia.gov/outlooks/aeo/nems/documentation/hsm/pdf/HSM_AEO2026.pdf.

production; once production enters terminal decline, operators can choose to decommission the site in any period.

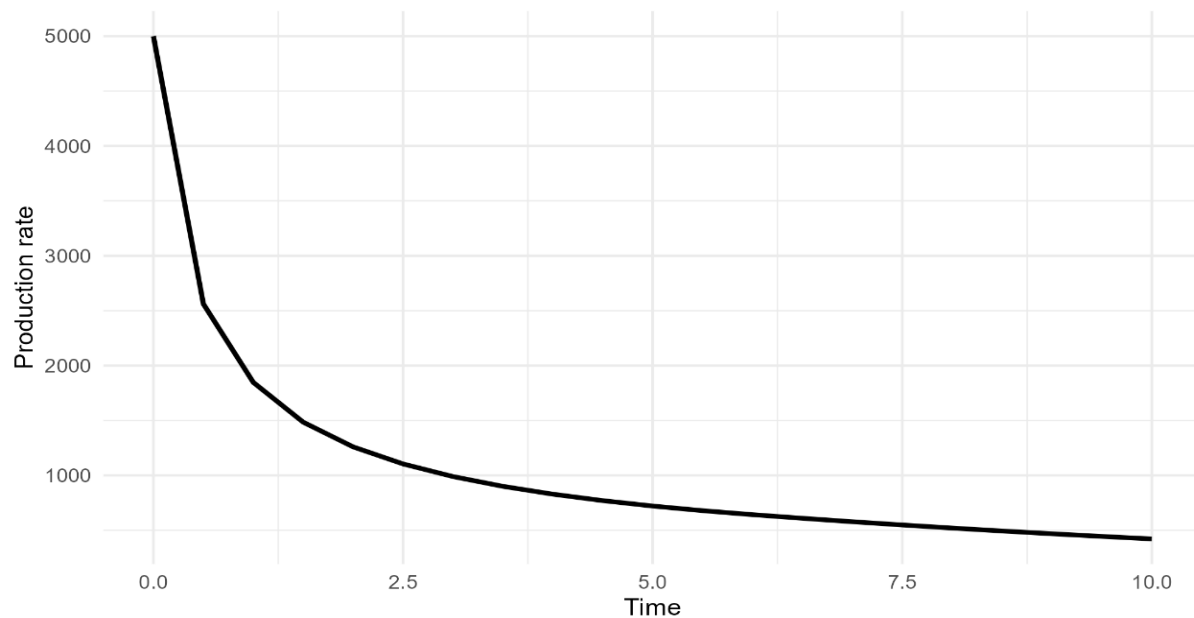


Figure 3-1 Example of a Modified Hyperbolic Decline Curve with Exponential Terminal Decline

For base year sites that have entered terminal decline, the model structure and solution are based on methods developed and demonstrated in Clarke and Reed (1990) and Smith and McCardle (1998). The model assumes that, in each year, flow profits for a given site are defined as the product of the commodity price and the production level less state severance taxes, landowner royalties, and fixed operating costs.³² Most sites sell both oil and gas, so the profit includes the sum of total revenue from both commodities. Both prices and quantities are assumed to follow exogenous trajectories from the perspective of the site operator. From the perspective of the operator, revenues are assumed to evolve according to a geometric Brownian motion

³² Our model does not account for the section 45I marginal well tax credit, the value of which depends on how oil and gas prices compare to calculated reference prices. When commodity prices are high, the credit value is low or zero. In recent years, gas prices have been low enough to set credit values near \$0.80 per mcf (<https://rskadvisors.com/insights/marginal-well-credit-2026>). Our analysis assumes that commodity prices are high enough to keep the tax credit from having significant value, but its existence creates a sort of insurance that would be expected to limit the downside risk of continuing to operate sites that is not captured in our model. Another tax incentive that our model does not account for is the section 611/613 percentage depletion tax deduction, which lowers the tax burden for independent oil and gas producers and can vary in magnitude year to year. Currently, percentage depletion is calculated by applying a 15% reduction to a marginal well property's taxable gross income (<https://nswa.us/percentage-depletion/>). We are researching the details of this tax credit and exploring whether and how to reflect it in our analysis.

process,³³ the realizations of which are assumed to be the product of the equilibrium domestic market prices and exogenous production levels.

Production continues in each period until operators decide to permanently decommission the site, at which point revenues and fixed operating costs cease and a one-time decommissioning cost is incurred. Intuitively, the value of maintaining production in a period comes from the revenues generated; the delay in paying for decommissioning, which is proportional to the operators' internal discount rates; and the option value of resolving uncertainty over the revenue path. The value of decommissioning a site comes from avoiding the fixed operating costs.

As demonstrated in Clarke and Reed (1990), our model set-up admits a simple decision rule for determining the optimal decommissioning strategy. In the first period in which revenue falls below a threshold, it is optimal for the operator to decommission the site. For a special case of the model in which the operator perceives no uncertainty in the revenue path, the revenue threshold is equal to the fixed operating costs less the value of delaying incurring the decommissioning cost for an additional period. We call this case the “deterministic” version of the decommissioning model, while the less restrictive version is identified as the “stochastic” version. In the stochastic version in which the uncertainty of the future revenue path is considered, the threshold is equal to the deterministic threshold multiplied by a weighting factor that reduces its value and thus increases the range of revenues over which operation should continue. In either case, the threshold can be analytically derived and is a function of the model parameters.

The implications of the decommissioning model choice are demonstrated in Figure 3-2 and the number of decommissioned wells per year are outlined in Table 3-1.³⁴ The trajectory of

³³ We assume the natural log of site revenues net of royalty and severance tax payments ($r_{i,t}$) evolves according to geometric Brownian motion described by the stochastic differential equation $dr_{i,t} = d \cdot r_{i,t}dt + \sigma \cdot r_{i,t}dW_t$, where d represents a drift parameter, σ represents a diffusion parameter, and W_t represents a standard Wiener process (and so dW_t is white noise). For more details, please see Section 2.3.1 of the *Technical Support Document: Crude Oil and Natural Gas Partial Equilibrium Model Documentation* (U.S. EPA, 2026) which can be found in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2025-0163>.

³⁴ The stochastic version makes operators consider the impacts of future commodity price uncertainty in their decision-making. Therefore, there is option value in delaying the decision in case commodity prices increase. For our given parameterization, that option value means that operators tend to pause decommissioning. This effect exists in both the reference and baseline/policy scenarios, so we see a gap in all years. Detailed information on

operating well counts at base year sites over time is illustrated for the reference, baseline (March 2024 Final Rule and December 2025 Final Rule), and proposal scenarios. Across all scenarios, significantly more wells are estimated to operate in all years under the stochastic version. For the deterministic version, a substantial number of wells are decommissioned in the initial model year, even in the absence of regulation. In the baseline scenario, there is substantial decommissioning in the initial year of the EG OOOOc (2029), particularly for the deterministic version of the model, in which almost 200,000 wells are estimated to cease operation. Under the proposed rule, the estimated counts of decommissioned wells decrease by an order of magnitude for both model versions. When considering these results, it bears mentioning that there is significant uncertainty around the scope of certain regulatory costs, particularly associated gas, and fixed operating costs and tax incentives for marginal wells, all of which may result in overestimating the impacts of the 2024 Final Rule on well decommissioning. Tax incentives are addressed in footnote 32. For associated gas, see Section 3.3.1 for description of how associated gas is treated in the model. More generally, see Section 7.4 for a discussion of key analytic

the decommissioning model is available in the *Technical Support Document: Crude Oil and Natural Gas Partial Equilibrium Model Documentation* (U.S. EPA, 2026) which can be found in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2025-0163>.

uncertainties.

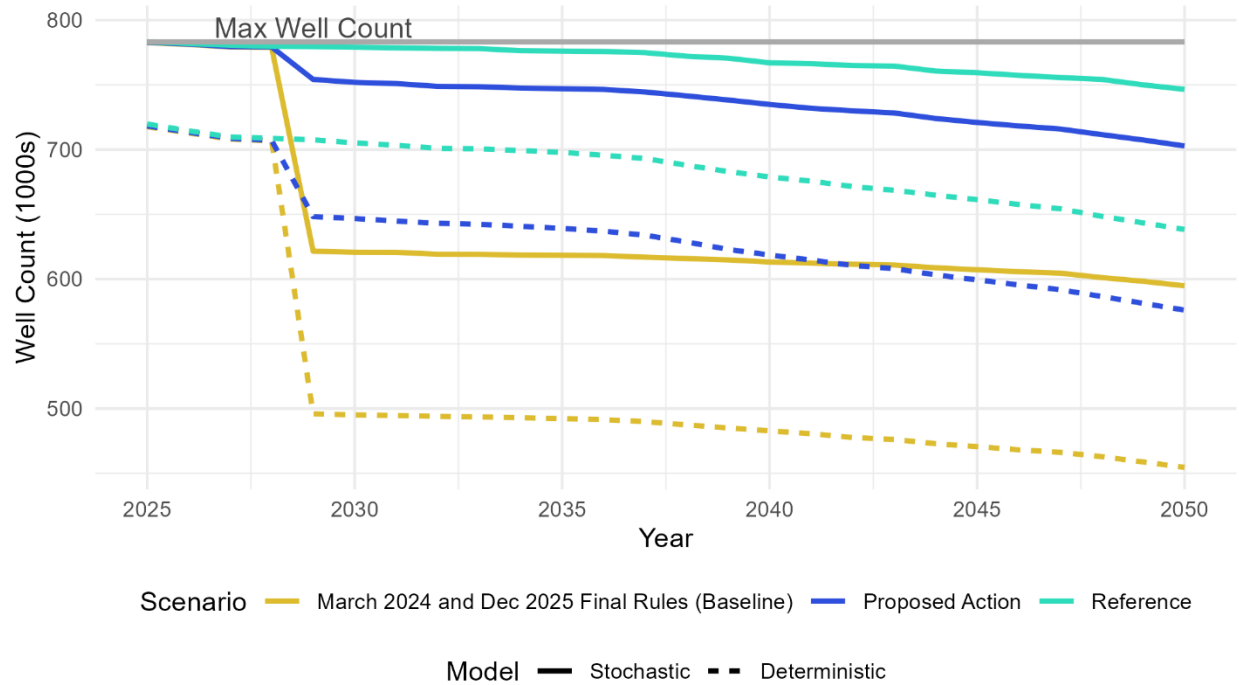


Figure 3-2 Base Site Well Count Comparison between Decommissioning Model and Scenario

Table 3-1 Decommissioned Wells per Year

Year	Proposed Reconsideration	Co-Proposal
2026	1,344	1,352
2027	2,020	2,018
2028	259	257
2029	25,032	25,785
2030	2,271	2,265
2031	922	922
2032	2,170	2,171
2033	269	268
2034	1,036	1,039
2035	490	484
2036	575	578
2037	1,964	2,044
2038	3,006	2,892
2039	3,183	3,227
2040	3,437	3,305
2041	2,965	3,110
2042	1,929	1,930
2043	1,680	1,666
2044	4,243	4,237
2045	3,099	3,089
2046	2,667	2,443
2047	2,369	2,505
2048	4,325	4,077
2049	4,152	4,445
2050	4,627	4,601

The universe of base year sites is constructed by processing downloads of Enverus data at the well³⁵ (in most cases) or lease (mainly for wells in Kansas and Michigan) level, filtering out any wells with a status other than “Active.” We further restrict our dataset to only wells that have a completion and first production date prior to the end of the base year, have Enverus decline curve parameters (which have the modified hyperbolic functional form described above), and are located onshore. After the initial data culling step, we have a set of wells with identifiers (API well numbers), location (latitude, longitude, county, and state), drilling type (conventional or

³⁵ The downloaded well-level data from Enverus are at the API14 level, which distinguishes across side-tracks and recompletions.

unconventional), completion and first production dates, API gravity for liquids production (limited observations), and decline curve parameters for both oil and gas production.

The well data are aggregated to the site level. We use Enverus's Prism application to download data mapping individual wells to well pads, a term that we use synonymously with "well sites." For well sites that have more than 20 associated wells, we break them into bins of equal size and assign wells to the bins based on a k-means algorithm over their geographic coordinates and redefine the bins as the actual well sites. We assign the drill type of a site as unconventional if at least one well at the site is coded as unconventional.³⁶ For each site, we define its effective date as the most recent of all the completion and first production dates across all wells at the site; the effective dates are then used to assign vintages with which to classify sites.³⁷ To construct site-level decline curve parameters, we fit curves to the sum of future modeled production for all wells on each site with multiple wells. For lease-level observations, we assume that the relevant unit of decision-making is the entire lease, and therefore the site is the lease property. In cases in which we are working at the lease-level, we assume all production decline is exponential at the terminal rate since Enverus does not provide estimated decline curve parameters for those entities.

Calibration of production from base year sites in the model proceeds as follows. First, since we don't model natural gas liquids (NGL) production, we estimate state-level dry gas production by scaling the Enverus-derived future gas production by EIA's state-level ratios of dry-to-wet gas production in the base year. We then scale production of each commodity by state-level EIA-to-Enverus production ratios in the base year to account for any systematic differences in production reporting across the two sources of data. Next, we solve the program for each site using the domestic commodity prices from the AEO2025 Reference Case described above. Finally, decommissioning decisions are applied to the production trajectories of each site and production is summed to the state level for each year.

³⁶ Our base year site dataset has 527,031 conventional and 82,340 unconventional sites.

³⁷ The vintage bins we use distinguish sites with effective dates prior to 1/1/2000 (Bin 1), effective dates between 1/1/2000 and 8/24/2011 (Bin 2), effective dates between 8/24/2011 and 9/18/2015 (Bin 3, affected by NSPS OOOO but not NSPS OOOOa), and effective dates between 9/18/2015 and 12/31/2019 (Bin 4, affected by NSPS OOOOa).

3.2.2 *Projected Well Sites*

Supply from projected well sites is modeled via constant price elasticities for drilling. Since there is empirical evidence that the drilling elasticities differ between oil and gas sites,³⁸ we distinguish production as coming from “oil” or “gas” sites based on their gas-to-oil (GOR) ratios. We assume that once sites are drilled, production declines exogenously according to region-specific modified hyperbolic decline parameters. Our formulation assumes that oil site drilling only responds directly to changes in oil prices, and gas site drilling only responds directly to changes in gas prices, even though both site types might produce some quantity of both commodities.

To estimate the annual decline factors of projected site production, we use Enverus well site data, filtered on sites of recent vintage under the assumption that those sites will best reflect the characteristics of future production sites.³⁹ For each site in the filtered set, we calculate annual fitted production for the site’s first 30 years. For each state with observations in the dataset, we sum production of each commodity over the sites to the state level and fit a hyperbolic-to-exponential decline curve for each state/commodity pair.

Calibration of the supply function scale parameters requires estimates of reference production from projected well sites in their initial year for each commodity, disaggregated by GOR bin (oil or gas site types). We calculate reference production from projected well sites in their initial year recursively. For any year, initial year reference production from projected well sites of that vintage is the residual of total reference onshore production after removing reference production from base year well sites and reference production from projected well sites from prior vintages. Finally, reference initial year production from projected well sites is disaggregated into production of each commodity from oil and gas sites based on proportions derived from analysis of the same set of recently completed sites used to derive the state-level decline curves.

³⁸ Well type is constructed by calculating the site- or lease-wide gas-to-oil ratio (GOR); if $GOR > 100,000$ mcf per bbl, then the well is assumed to be a natural gas well, otherwise, it is assigned as an oil well.

³⁹ Specifically, we restrict the set of sites to those completed since the NSPS OOOOa proposal.

3.3 Regulatory Costs

The proposed action regulates emissions of VOC and/or methane and consists largely of equipment-based performance standards that require operators to capture potential emissions and route them to gathering lines or control devices (e.g., combustion devices). For the analysis in this reconsideration, we evaluate the impacts of compliance costs associated with the six emission sources discussed in Section 1.2: fugitives, process controllers, pneumatic pumps, associated gas, storage vessels, and liquids unloading.

Unlike some other industrial sectors, in which there are relatively few production facilities and information on the emissions sources at the site are more readily available, oil and gas production sites are numerous (~1 million wells across more than half a million sites) and information on specific emissions sources at the site-level is unavailable. Below, we discuss how we use survey data to create distributions from which to assign equipment and emissions sources to sites using a Monte Carlo framework, and ultimately how those draws are used to estimate site-level compliance costs.

3.3.1 Equipment Assignments

Equipment distributions are based on analysis of several site-level surveys, most notably the EPA's 2016 Information Collection Request for the Oil and Natural Gas Industry (2016 ICR) and fugitive emissions monitoring data provided by the American Petroleum Industry (API). We first use the site-level survey data to construct initial equipment distributions, and then we apply those distributions to our base year well site dataset. The use of the 2016 ICR and API surveys resembles what was done for the 2024 Final Rule RIA.⁴⁰

Our first step is to process the 2016 ICR data to estimate distributions for certain major equipment (separators, compressors, and dehydrators) and storage tanks. We estimate the

⁴⁰ For more information on the ICR, see [https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/background-information-request-oil-and-natural-gas-industry](https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/background-information-request-oil-and-natural-gas-industry/background-information-request-oil-and-natural-gas-industry) for more information on the ICR. The ICR was withdrawn in 2017, but not before significant amounts of data were collected (>100,000 sites). 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>. For the API survey data, see Attachment 4: API Well Site Fugitive Monitoring Data (Microsoft Excel workbook) located at <https://www.regulations.gov/document/EPA-HQ-OAR-2017-0483-0036>. The dataset contains survey data on 2,183 gas well sites and 1,742 oil well sites and was submitted to the Agency in 2018.

proportions of sites in eleven equipment categories and two tank bins for all combinations of oil and gas sites, production bins (low versus non-low), and single and multi-well sites at the regional level, for regions for which the data was sufficient. For a few regions, all site observations within each region were pooled to estimate equipment and storage vessel bin proportions.

Since the ICR data does not contain information on heater-treaters and process heaters, we supplement with information on those equipment types from the API survey data. Grouping the API survey sites by the presence of separators, compressors, and/or dehydrators (i.e., has major equipment surveyed in the ICR or not); regions; site types (oil or natural gas); and well count bins (single or multi), we calculated the proportion of sites with heater-treaters, and process heaters for each combination. The proportions were then applied to the equipment bins developed from the ICR data to estimate site proportions for all equipment bin combinations including heater-treaters and process heaters. However, since the API survey was intended to reflect the types of sites that would be impacted by NSPS OOOOa requirements, we expect that such sites would be expected to be larger and have more equipment than the overall population of production sites. Therefore, the equipment proportions for heater-treaters, process heaters, and headers were reduced by half for older (pre-NSPS OOOO) sites.

We also estimate average equipment and storage vessel counts for each equipment and storage vessel bin combination. For single well sites, there are distinct estimates of separators, compressors, and dehydrators for each combination of region, equipment bin, and storage vessel bin at a minimum, with further disaggregation by site type and production level where possible. For multi-well sites, we fit linear models to estimate average equipment counts as a function of site well counts, constraining the estimated parameters to agree with the equipment bins for all possible well counts (e.g., at least one separator in each equipment bin that denotes the presence of a separator, at least two separators in the equipment bin that designates more than one separator at the site). Average equipment counts for heater-treaters and process heaters are calculated from the API data for each combination of region, site type, well count bin, and equipment presence. Finally, we assume all gas well sites have meters/piping.

In addition to the equipment distributions described above, we also construct distributions for process controller types and pumps. For process controllers, we assume that 8 percent are low

bleed, 85 percent are intermittent bleed, and 7 percent are high bleed.⁴¹ We use that distribution and the composition of sites in our base year well site dataset to calculate conditional distributions for sites that are and are not eligible to have high-bleed controllers, assuming that no high-bleed controllers exist at post-OOOO sites in any state and at pre-OOOO sites in California, Colorado, or Utah. For pumps, 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).⁴² 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.

The final emissions sources we construct distributions for are liquids unloading and associated gas. Regarding liquids unloading, based on survey results provided by API and the American Natural Gas Association (ANGA), we assume that 36 percent of gas wells have plunger lifts.⁴³ Of those sites, 21 percent have events that vent gas to the atmosphere, while 9.3 percent of gas wells that do not have plunger lifts have events where venting occurs. We use that distribution and the composition of sites in our base year well site dataset to calculate conditional distributions for low production gas sites under the assumption that non-low producing gas sites do not have liquids unloading events. For associated gas, we only capture emissions from this source for sites that do not report gas sales. For those sites, we assume that non-low producing sites flare their associated gas. For low producing sites without gas sales, we calculate binomial (conditional) distributions for the presence of a flare for each HSM region using the 2016 ICR data.⁴⁴ We assume that sites with flares use them to combust associated gas emissions; otherwise, associated gas is vented.

For each Monte Carlo simulation, we use our set of conditional distributions over equipment and emissions sources to perform random draws and characterize sites. Counts of

⁴¹ Assumptions of the distributions for process controller types based on Tupper (November 2019), *API Field Measurement Study: Pneumatic Controllers*, available at: https://www.epa.gov/sites/default/files/2019-11/documents/ghgi_nov2019workshop_tupper2.pdf.

⁴² 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.

⁴³ See page 12 of the September 2012 API/ANGA survey report titled *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production*, available at <https://www.api.org/news-and-media/news/newsitems/2012/oct-2012/~media/files/news/2012/12-october/api-anga-survey-report.pdf>.

⁴⁴ The proportion of sites that report having flares range from 0.2% (Midcontinent region) to 10% (Northern Plains region).

process controllers are assigned according to controller-per-equipment factors presented in the Supporting Information of Zavala-Araiza et al. (2017).⁴⁵ Once equipment and emissions sources have been assigned to sites, we can estimate site emissions in the absence of control, regulatory outcomes, and compliance cost and emission changes.

3.3.2 *Potential Emissions Estimates*

To estimate site emissions for the sources captured in our analysis, we incorporate the emissions factors from the BSER analysis performed for this proposed reconsideration and summarized in the Technical Support Document (TSD). Where necessary, we also leverage similar information from the March 2024 Final Rule package, since the analysis for the proposal focuses on low producing wells while the March 2024 Final Rule RIA applies to all sites.

To estimate emissions from fugitive components for a site, we apply per-component and thief hatch emissions factors to the total number of estimated components at the site. The per-component emissions factor is calculated as the average of the per-component uncontrolled emissions rates for the four original model plants (single wellhead only, small wellsite, multi-wellhead only, and large wellsite) analyzed for the BSER. The thief hatch emissions factor is calculated as the difference in uncontrolled emissions from the large wellsite with and without a controlled storage vessel from the March 2024 Final Rule analysis. To calculate the total number of components at a site, we use the equipment counts described above and apply component count factors according to Tables W-1B (for gas well sites) and W-1C (for oil well sites) from 40 CFR part 98, Subpart W.⁴⁶ The thief hatch emissions factors are applied to sites assumed to have controlled storage vessels, which is estimated based on a combination of estimated emissions, and requirements under NSPS OOOO/OOOOa/OOOOb and EG OOOOc.

⁴⁵ Using data from Allen et al. (2015), the authors estimate 0.42 controllers per wellhead, 0.90 controllers per plunger lift, 1 controller per separator at gas sites without liquids production, 2.06 controllers per separator at sites with liquids production, 1.5 controllers per process heater, 4.3 controllers per compressor, and 2.5 controllers per dehydrator. To prevent certain sites from having a fractional controller count, we assume 1 controller per plunger lift. We also assume, in lieu of a specific estimate, that each heater-treater has 1.5 controllers (same as process heaters and roughly the midpoint between separators at sites with and without liquids production). Finally, based on a review of the underlying data from Allen et al. (2015), we assume that all controllers at wellheads qualify as emergency shutdown devices and are thus not subject to the controller requirements.

⁴⁶ See <https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98>.

Emissions potentials for the other emissions sources are calculated similarly. For sites assigned to have storage vessels, emissions from those sources are calculated by applying per-barrel of throughput emissions factors to site-level production levels.⁴⁷ For sites with potential associated gas emissions (i.e., oil sites without gas sales), we assign a per-barrel emissions factor based on an assumed GOR value of 500.⁴⁸ Process controller, pump, and liquids unloading event emissions factors are taken directly from the BSER analysis.⁴⁹

3.3.3 Compliance Activity Assignments

After assigning equipment and calculating potential emissions for sites, we assign compliance activities to sites for each scenario in line with the regulatory requirements described in Section 1.2. Our assignment of compliance activities resembles a standard engineering analysis: compliance activities are exogenous to sites and we do not attempt to model choices over multiple compliance options, other than the option for base year well sites to comply by decommissioning. As such, we also do not attempt to model any endogenous choices to conduct compliance activities that might be profitable to certain sites in a baseline scenario (e.g., instituting a more frequent fugitive emissions detection and repair program to capture additional saleable gas).

Compliance activities are assigned for each model year, and sites are unable to preemptively comply even in instances in which doing so may increase profits. For equipment-based regulations such as the NSPS OOOO/OOOOa/OOOOb and EG OOOOc, we assume that regulatory compliance starts in a certain year and persists indefinitely until it is superseded by another regulation. In some cases, the regulatory requirements and associated compliance activities depend on other site characteristics (e.g., the production level of the site, the vintage of the site, the number of pieces of major equipment on the site, or the PTE of storage vessels on

⁴⁷ 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, from the November 2021 NSPS OOOOb/EG OOOOb Proposal TSD. Condensate emissions factors were applied to sites with API gravity greater than or equal to 40, while oil emissions factors were applied to sites with API gravity less than 40. The API gravity field is populated in Enverus for some sites. For others, the average API gravity across the sites that did report for the same HSM region was applied. In cases where there were no API gravity observations within an HSM region, the national average was applied.

⁴⁸ See the *Technical Support Document: Crude Oil and Natural Gas Partial Equilibrium Model Documentation* (U.S. EPA, 2026) which can be found in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2025-0163>.

⁴⁹ Ibid.

the site), and so we perform the appropriate calculations and categorizations before assigning compliance activities.

3.3.4 Compliance Cost and Control Efficiency Assignment

Compliance costs and emissions levels are assigned to base year and projected well sites based on their assumed compliance activities. Compliance costs for equipment-based standards tend to consist of fixed annual costs and one-time capital costs. We apply capital costs in the first year that a compliance activity is assumed to begin and fixed annual costs in the first year and all subsequent years until the site experiences a change in compliance activity. We assume capital costs (or some portion thereof) are again incurred at the end of a control's prespecified lifetime. Emissions levels are calculated by multiplying a baseline "no control" emissions level for a given emissions source, or PTE, by an assumed control efficiency. Below, we discuss cost and emissions parameterization for modeled emissions sources and related compliance activities.

For fugitive emissions control, we apply control costs and efficiencies based on the model plant assessments from the BSER analysis. In that analysis, there are four model plants: single wellhead, small well site, multi wellhead, and large well site, which map to the descriptions from the regulatory requirements tables, Table 1-1 and Table 1-2. For each Monte Carlo simulation, all base year sites are mapped to one of those model plants and assigned its control cost and efficiency characteristics for the applicable LDAR requirement. In the case where sites are assumed to comply with the semiannual OGI inspection requirement from the NSPS OOOOa, the control cost and efficiency characteristics from the March 2024 Final Rule TSD are used (with the costs escalated from a 2019 to 2024 dollar year) since that specific monitoring program was not analyzed for this action.

For pneumatic device control, the control costs depend on the number and types of controllers and pumps at the site. In the case of a zero emissions requirement, we assume, consistent with the BSER analysis, the installation of a new generator to power electronic controllers. The generator and control panel do not depend on the number of controllers at the site, but the replacement of the controllers with electronic versions does. For sites that also have pumps, we assume that those are also replaced with electric versions and powered by the same system. In addition, we assume that the zero emissions system remains in place even if the requirement goes away because of the site transitioning into marginal status. For controller

inspection programs, we assume they result in an incremental addition to the operating cost of the fugitive component program. The costs are scaled by the number of intermittent bleed controllers at the site, with a minimum cost level set at the costs associated with a site with three intermittent bleed controllers. In addition, any high bleed controllers at sites with inspection program requirements are assumed to be replaced with low bleed controllers for a one-time capital cost.

For associated gas control, compliance costs are incremental to the assumed treatment of associated gas in the absence of federal regulation, as discussed in Section 3.3.1. Therefore, if a site is already assumed to flare its associated gas in the baseline, and the scenario would require associated gas to be flared, there is no cost or emissions impact at the site. In addition, if there's a requirement that associated gas be routed to a sales line, we assume that the site's gas will be routed even if the requirements become less stringent over time (95 percent control or no requirement) since the upfront capital costs have already been incurred. In any case, the cost assignments for routing to a sales line or 95 percent control match what is presented for the BSER analysis.

For storage vessel control, we maintain the analysis that was performed for the March 2024 Final Rule, updating the dollar year from 2019 to 2024. The costs of control (flares) are based on the BSER analysis for the 2021 NSPS OOOOb/EG OOOOc Proposal, with capital and annual costs equal to a minimum value below a 50 tpy CH₄ emissions threshold and following a quadratic cost function for sites with emissions above that threshold.⁵⁰ The 50 tpy CH₄ emissions threshold is based on the estimated emissions in the initial year of control.

3.3.5 Incorporation of Costs into the Model

Because the treatment of base year and projected sites differ in the model, the application of regulatory costs to each differs as well. For base year sites, the regulatory costs are entered in the same fashion as they are applied, as one-time capital and fixed annual operating costs. For projected sites, the future stream of regulatory costs are summed to the state level (along with

⁵⁰ 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 CH₄.

projected production) and levelized over 20 years to construct a per-unit (either per barrel or Mcf) cost that can be applied to the isoelastic projected site supply function similar to a standard tax on production that shifts the marginal cost curve.

The incorporation of regulatory costs for base year sites requires some modifications to the model described in Section 3.2.1. In the absence of regulatory costs, the model solution is characterized for instances where the nonrandom parameters, including operating costs, are fixed over time. However, we model the compliance costs for the requirements in the baseline and policy scenarios as having one-time capital outlays followed by annual increases to the normal annual operating costs. The capital outlays are assumed to occur in the initial production year for NSPS OOOOb sites and the year of the EG OOOOc compliance deadline for all other sites. Annual compliance costs are assumed to start in the same year as the capital costs and continue in perpetuity (or until the requirements no longer apply).

To account for regulatory cost shocks, we adjust the solution algorithm depending on whether sites are NSPS OOOOb sites or EG OOOOc sites. For NSPS OOOOb sites, we assume that the capital costs are sunk and decision rule described in Section 3.2.1 applies, with the annual costs simply reflecting the sum of annual operating costs without control and annual compliance costs. In instances where the requirements change for a site, such as in the case where a non-marginal site becomes marginal, we continue to apply the same solution algorithm without accounting for the anticipatory effects of a regulatory cost change. We expect the impacts of this modeling simplification to be minimal in this analysis, as most policy changes occur as a result of crossing into the marginal production range, which is above the production levels at which we would expect decommissioning to occur given our compliance cost assumptions.

For EG OOOOc sites, the solution algorithm adjustments are more complex. First, we divide the time horizon into pre-regulatory and post-regulatory segments. The pre-regulatory segment is assessed using the same comparison of revenues and the decommissioning threshold. In the year in which compliance costs for EG OOOOc are assumed to occur (2029), we compute the going-forward value of the site (i.e., the present value of the expected future profits resulting from optimal behavior) taking the annual compliance into account. Sites are assumed to be decommissioned in that year if the costs of continuing to operate (the compliance capital costs

the going-forward value of the site) exceed the decommissioning cost.⁵¹ Beyond the initial compliance year, the normal decision rule based on the decommissioning threshold (adjusted for the annual compliance costs) is applied.

By treating operators' decision-making in this way, we are implicitly assuming that they are not exercising foresight over the expected future compliance costs in the years prior to the EG OOOOc compliance deadline. Alternatively, we could apply backward induction and assume that operator's take the expected future value of the site (including the effect of the EG OOOOc compliance costs) into account when making decisions in the pre-compliance period. However, this formulation would resemble the structure of an American call option, which does not admit an analytic solution and hence numerical methods would be required. To avoid significant additional computational burden, we choose not to pursue this approach.

To calculate compliance cost and emissions impacts for projected sites, we perform separate sets of Monte Carlo equipment draws on the subset of sites described in Section 3.2.2; assign PTE estimates, compliance activities, control costs, and control efficiencies; aggregate to the state level; and calculate the median values across the draws at the state level separately for both oil and gas sites. For each year, we calculate a levelized, per-unit regulatory cost shock that shifts the supply curve for initial year production from wells drilled in that year. In addition, we also calculate future streams of compliance costs (capital and annual) and emissions per unit of initial year production of the commodity that matches the site type in all years (i.e., gas production from gas sites, oil production from oil sites). This allows us to calculate total compliance cost and emissions impacts using a post-processing step that scales the per-unit cost and emissions factors by state-level production from projected sites in their initial year.

⁵¹ In this model, the marginal cost and revenue of wells are the annual revenues from production and annual costs. The model also incorporates one-time capital costs of compliance and decommissioning costs, and option value over the future (uncertain) commodity price paths. Therefore, the decision criterion includes a threshold analysis comparing the capital costs of compliance with the value of continuing operations and accounts for future price uncertainty. See Section 2.3.1 of the *Technical Support Document: Crude Oil and Natural Gas Partial Equilibrium Model Documentation* (U.S. EPA, 2026) which can be found in the docket here: <https://www.regulations.gov/document/EPA-HQ-OAR-2025-0163>.

3.4 Model Solution

The model is solved for each Monte Carlo simulation, scenario, and decommissioning model version (stochastic or deterministic, as described in Section 3.2.1) through a series of steps. Once the inputs have been constructed for base year sites, an initial solve of the decommissioning model based on reference commodity prices and without regulatory control costs is used to calibrate projected site supply through the steps outlined in Section 3.2.2.

Once the model has been calibrated, the model is solved through an iterative procedure. First, the proposed standards enter into the model through applying regulatory costs to both types of sites. The decommissioning model is solved once again, still with reference commodity prices. The model solution is used to calculate production of both oil and gas from base year sites in all modeled years at the state level, which is fed into the broader market equilibrium model as an exogenous parameter. Applying the levelized regulatory cost shocks to projected site production, the model solves so that prices equalize both (1) foreign supply to the U.S. market with domestic import demand, and (2) domestic supply with domestic demand for domestic production and foreign demand for U.S. production. The resulting prices are then fed back into the decommissioning model, and the process repeats until a convergence criterion is met. Once the model has solved, we collect the output equilibrium prices and quantities, which can then be used to calculate a variety of impact metrics related to economic welfare and emissions.

3.5 Calculation of Impacts

Once the model solutions have been obtained, cost and emissions impacts can be calculated. Given the modeling structure, the impacts need to be aggregated across both the decommissioning model and the market equilibrium model. From the decommissioning model, we calculate aggregate profits and emissions. From the market equilibrium model, we calculate consumer surplus, producer surplus for projected sites, and emissions. The results are then combined and differenced from the baseline scenario to estimate a partial equilibrium approximation of a social cost welfare metric and emissions changes.

For base year sites, the calculation of profits is straightforward. Revenues consist of production times commodity prices, summed over commodities, after removing ad valorem severance taxes and landowner royalties. Costs include annual operating costs (not including

compliance costs), decommissioning costs, and compliance costs (capital and annual). Both are calculated based on the model results for each site and then aggregated across all sites. The calculation of emissions consists of a simple aggregation of site-level estimates.

For projected sites, the producer surplus calculation is based on the supply curves for initial year production combined with streams of compliance costs. In each year, producer surplus is calculated as the difference between revenue from initial year production and the area under the supply curves for initial year production. Compliance costs, as well as emissions, are calculated by applying the per-unit factors to initial year production, as described in Section 3.3.5, to construct future streams for each vintage of projected sites.

Finally, consumer surplus is calculated using the domestic demand curves for each commodity in each year. Since the integrals of the inverse demand curves do not converge for the elasticity values used in our analysis, we instead integrate the area under the demand curves over a domain that ranges from the equilibrium composite commodity price to an arbitrary choke price set to be twice the maximum equilibrium price across all scenarios. As a result, only the differences in consumer surplus across scenarios have meaning.

3.6 References

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4 QUANTIFIED CHANGES IN ECONOMIC SURPLUS

4.1 Introduction

This section reports the compliance cost and economic surplus analyses performed for the proposed reconsideration of the March 2024 Final Rule requirements. We quantify changes in economic surplus within the oil and natural gas market, including the sum of changes in producer surplus (not including the value of product recovery), which account for changes in regulatory compliance costs; consumer surplus, which is the economic benefit received by the consumer, as measured by the cumulative distance between consumers' willingness-to-pay and market prices; and the value of product recovery from compliance activities. The March 2024 Final Rule RIA provides a basic description of emissions sources and the controls evaluated for each source that can facilitate the reader's understanding of the presented economic analysis.^{52,53} The cost estimates provided for this proposed action are presented in 2024 dollars and the analytical timeframe for this action is 2027 to 2050.⁵⁴

4.2 Compliance Costs

Table 4-1 summarizes the estimated compliance cost savings for the evaluated emissions sources. Total costs consist of capital cost savings and annual operating and maintenance cost savings. Capital cost savings include the capital cost savings from the requirements on newly affected pneumatic devices, storage vessels, and associated gas facilities, as well as the planning costs associated with monitoring requirements for fugitive emissions at well sites. These cost savings 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 cost savings are due to requirements on fugitive emissions, pneumatic devices, storage vessels, associated gas, and liquids unloading.

As illustrated in the table, we estimate a significant reduction in compliance costs overall. There are large undiscounted capital cost savings of approximately \$14 billion in the compliance

⁵² Available at <https://www.regulations.gov/document/EPA-HQ-OW-2022-0801-2626>.

⁵³ Several emissions sources subject to NSPS OOOOb and EG OOOOc requirements. This analysis considers the following emissions sources: fugitive emissions, pneumatic controllers, pneumatic pumps, storage vessels, equipment leaks at gas plants, and associated gas.

⁵⁴ The March 2024 Final Rule RIA presented analysis in 2019 dollars with an analytical timeframe of 2024 to 2038.

year, 2029. Note that while we assume that compliance costs occur in a single year, in practice the EG OOOOc gives States and operators the flexibility to spread these activities over a longer period. While we do not distribute compliance expenditures across these years in the RIA, it is certainly possible that States and operators will avail themselves of this flexibility.

Table 4-1 Undiscounted Compliance Cost Savings under the Proposed Reconsideration from 2027–2050 (millions 2024\$)

Year	Capital Cost Savings	Operating and Maintenance Cost Savings	Change in Revenue from Gas Recovery	Net Compliance Cost Savings
2027	\$290	\$64	-\$44	\$310
2028	\$280	\$78	-\$49	\$310
2029	\$14,000	\$1,800	-\$210	\$15,000
2030	\$260	\$1,800	-\$220	\$1,900
2031	\$270	\$1,800	-\$230	\$1,900
2032	\$270	\$1,900	-\$260	\$1,900
2033	\$270	\$1,900	-\$290	\$1,900
2034	\$280	\$1,900	-\$300	\$1,900
2035	\$270	\$2,000	-\$310	\$1,900
2036	\$260	\$2,000	-\$300	\$2,000
2037	\$410	\$2,000	-\$300	\$2,200
2038	\$250	\$2,100	-\$290	\$2,000
2039	\$250	\$2,100	-\$280	\$2,100
2040	\$250	\$2,100	-\$280	\$2,100
2041	\$250	\$2,200	-\$280	\$2,100
2042	\$260	\$2,200	-\$290	\$2,200
2043	\$260	\$2,200	-\$290	\$2,200
2044	\$260	\$2,200	-\$290	\$2,200
2045	\$420	\$2,300	-\$300	\$2,400
2046	\$260	\$2,300	-\$300	\$2,200
2047	\$260	\$2,300	-\$300	\$2,300
2048	\$270	\$2,300	-\$300	\$2,300
2049	\$260	\$2,300	-\$300	\$2,200
2050	\$250	\$2,300	-\$290	\$2,200

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

The projected compliance cost savings include changes in the revenue from natural gas recovery due to compliance activities projected under the proposed action. For the 2024 Final Rule, some requirements for fugitive emissions monitoring, pneumatic devices, associated gas, and liquids unloading are assumed to increase the capture of methane and VOC emissions that would otherwise be vented to the atmosphere. Since the proposed reconsideration lessens these requirements, we estimate less capture of natural gas through compliance activities.

We now present the compliance cost savings of the proposed action in a PV framework. The stream of the estimated cost savings for each year from 2027 through 2050 is discounted back to 2025 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 cost savings. 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 cost savings. In other words, the EAV takes the potentially “lumpy” stream of cost savings 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 4-2 shows the discounted stream of compliance cost savings discounted to 2025 using 3 and 7 percent discount rates from 2027 to 2050. The PV of the stream of cost savings discounted using a 3 percent discount rate and accounting for product recovery is \$42 billion, with an EAV of \$2.5 billion per year. The PV of the stream of cost savings discounted using a 7 percent discount rate and accounting for product recovery is \$29 billion, with an EAV of \$2.5 billion per year.

**Table 4-2 Compliance Cost Savings under the Proposed Reconsideration, 2027–2050
(million 2024 dollar, discounted to 2025)**

Year	3 Percent Discount Rate				7 Percent Discount Rate			
	Capital Cost Savings	Operating Cost Savings	Value of Product Recovery	Net Compliance Costs Savings	Capital Cost Savings	Operating Cost Savings	Value of Product Recovery	Net Compliance Costs Savings
2027	\$270	\$60	-\$42	\$290	\$250	\$56	-\$39	\$270
2028	\$260	\$71	-\$45	\$280	\$230	\$64	-\$40	\$250
2029	\$12,000	\$1,600	-\$190	\$13,000	\$10,000	\$1,400	-\$160	\$12,000
2030	\$230	\$1,600	-\$190	\$1,600	\$190	\$1,300	-\$160	\$1,300
2031	\$230	\$1,500	-\$200	\$1,600	\$180	\$1,200	-\$160	\$1,300
2032	\$220	\$1,500	-\$220	\$1,500	\$170	\$1,200	-\$160	\$1,200
2033	\$210	\$1,500	-\$230	\$1,500	\$160	\$1,100	-\$170	\$1,100
2034	\$210	\$1,500	-\$230	\$1,500	\$150	\$1,100	-\$170	\$1,000
2035	\$200	\$1,500	-\$230	\$1,400	\$140	\$1,000	-\$160	\$990
2036	\$190	\$1,500	-\$220	\$1,400	\$120	\$950	-\$140	\$930
2037	\$290	\$1,400	-\$210	\$1,500	\$180	\$910	-\$130	\$960
2038	\$170	\$1,400	-\$200	\$1,400	\$100	\$860	-\$120	\$840
2039	\$160	\$1,400	-\$190	\$1,400	\$96.00	\$820	-\$110	\$800
2040	\$160	\$1,400	-\$180	\$1,400	\$90	\$770	-\$100	\$760
2041	\$160	\$1,400	-\$180	\$1,300	\$85	\$730	-\$96	\$720
2042	\$150	\$1,300	-\$170	\$1,300	\$81	\$690	-\$90	\$690
2043	\$150	\$1,300	-\$170	\$1,300	\$77	\$660	-\$86	\$650
2044	\$150	\$1,300	-\$170	\$1,300	\$72	\$620	-\$82	\$610
2045	\$230	\$1,300	-\$160	\$1,300	\$110	\$590	-\$77	\$620
2046	\$140	\$1,200	-\$160	\$1,200	\$63	\$550	-\$73	\$540
2047	\$140	\$1,200	-\$160	\$1,200	\$60.00	\$520	-\$68	\$510
2048	\$140	\$1,200	-\$150	\$1,100	\$57	\$480	-\$63	\$480
2049	\$130	\$1,100	-\$150	\$1,100	\$51	\$450	-\$58	\$440
2050	\$120	\$1,100	-\$140	\$1,100	\$47	\$420	-\$54	\$410
PV	\$16,000	\$30,000	-\$4,200	\$42,000	\$13,000	\$18,000	-\$2,600	\$29,000
EAV	\$970	\$1,800	-\$250	\$2,500	\$1,100	\$1,600	-\$220	\$2,500

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding. Cost savings and revenue from product recovery in each year are discounted to 2025.

4.3 Quantified Changes in Economic Surplus

The previous section provides a useful estimate of the regulatory compliance cost savings, but they do not capture broader market-level costs that result from changes in producer and consumer behavior. The decommissioned base year sites change the flow of costs and revenues at those sites, including one-time costs associated with plugging. To account for those effects, we consider changes in producer surplus for base year sites as a more encompassing

welfare measure for those sites. For projected year sites, our model accounts for the impact of regulatory costs on drilling activity (as captured by initial year production), resulting in changes to producer surplus for those sites. For consumers, regulatory costs that shift the supply curves for oil and gas result in changes to equilibrium prices and quantities and, in turn, consumer surplus. Our estimates of the quantified change in economic surplus incorporates all these elements.⁵⁵

Table 4-3 summarizes the estimated stream of undiscounted values of quantified changes in economic surplus and its constituent parts. The table illustrates that increased surplus for both base year and projected sites are mostly driven by reductions in estimated compliance costs, as columns 2 and 5 (base year) and 3 and 6 (projected) sites are similar in magnitude. Moreover, base year sites experience the largest reductions in regulatory costs, which mostly occur in 2029 and beyond. Beyond the regulatory compliance cost impacts, we estimate significant additional producer surplus increases across the EG OOOOc start years (2029), driven by reductions in decommissioning cost expenditures as illustrated in Figure 3-1. In 2030 and beyond, the base year site producer surplus increases tend to be lower than those of regulatory cost savings because the sites are not decommissioned under the proposed reconsideration have negative operating profits. For projected sites, increased producer surplus is slightly larger in magnitude than cost savings because under the proposed reconsideration, there is increased production and associated revenues. On the consumer side, surplus tracks with estimated changes to market prices, which we detail in Section 6.1. We estimate consumer surplus to increase modestly in every year.

⁵⁵ We assume in the model that operators do not internalize the value of product recovery from compliance measures in their decision making, for reasons that are explained in Section 7.4, chiefly that the bulk of the type of emissions being addressed in the NSPS OOOOb and EG OOOOc come from the tails of the leak distributions, and operators might behave based on median, rather than mean, outcomes. Therefore, we assume that operators only respond to the compliance costs imposed by the regulation, which serves to shift the supply curve for drilling. The drilling elasticity captures some of the opportunity cost of capital effect, as we assume that decreases in regulatory costs are akin to increases in commodity prices, resulting in more drilling and greater production. One limitation of our model, however, is that it is composed of a series of static supply and demand curves, and we do not capture investment effects over time that could result from increases in producer surplus. A more comprehensive dynamic model would capture the treatment of the accrual of additional producer surplus over years, either through a direct representation of a capital stock equation (such as in a computable general equilibrium model) or outward shifts in future supply curves relative to the reference case. Mechanically, the latter would be the most immediately implementable formulation in the current model set up, but it is unclear how one would choose the magnitude of the shifts in future year supply curves. Therefore, we leave the possibility of dynamic modeling for future analyses.

Table 4-3 Undiscounted Compliance Cost Savings and Quantified Economic Surplus Impacts under the Proposed Reconsideration from 2027–2050 (million 2024 dollar)

Year	Base Year Site Compliance Cost Savings	Projected Site Compliance Cost Savings	Revenue from Gas Recovery	Base Year Site Producer Surplus	Projected Site Producer Surplus	Consumer Surplus	Total Change in Surplus ^a
2027	\$20	\$330	-\$44	-\$160	\$340	\$44	\$180
2028	\$20	\$340	-\$49	-\$160	\$340	\$55	\$190
2029	\$15,000	\$340	-\$210	\$19,000	\$340	\$110	\$20,000
2030	\$1,700	\$350	-\$220	\$1,600	\$350	\$100	\$1,800
2031	\$1,700	\$370	-\$230	\$1,600	\$370	\$98	\$1,800
2032	\$1,800	\$390	-\$260	\$1,600	\$390	\$100	\$1,900
2033	\$1,800	\$400	-\$290	\$1,700	\$410	\$100	\$1,900
2034	\$1,800	\$420	-\$300	\$1,700	\$430	\$98	\$1,900
2035	\$1,800	\$430	-\$310	\$1,700	\$440	\$96	\$1,900
2036	\$1,800	\$440	-\$300	\$1,700	\$450	\$94	\$1,900
2037	\$2,000	\$450	-\$300	\$1,800	\$460	\$90	\$2,100
2038	\$1,900	\$470	-\$290	\$1,700	\$470	\$89	\$1,900
2039	\$1,900	\$480	-\$280	\$1,700	\$480	\$90	\$2,000
2040	\$1,900	\$500	-\$280	\$1,700	\$500	\$92	\$2,000
2041	\$1,900	\$520	-\$280	\$1,700	\$520	\$96	\$2,000
2042	\$1,900	\$540	-\$290	\$1,700	\$540	\$98	\$2,100
2043	\$1,900	\$560	-\$290	\$1,700	\$560	\$100	\$2,100
2044	\$1,900	\$580	-\$290	\$1,700	\$580	\$100	\$2,100
2045	\$2,100	\$600	-\$300	\$1,900	\$600	\$100	\$2,300
2046	\$1,900	\$620	-\$300	\$1,700	\$620	\$100	\$2,100
2047	\$1,900	\$640	-\$300	\$1,700	\$640	\$100	\$2,100
2048	\$1,900	\$660	-\$300	\$1,700	\$670	\$100	\$2,200
2049	\$1,900	\$670	-\$300	\$1,700	\$680	\$100	\$2,200
2050	\$1,800	\$690	-\$290	\$1,700	\$690	\$100	\$2,200

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

^a Total change in surplus is calculated as the sum of base year site producer surplus, projected site producer surplus, consumer surplus, and revenue from gas recovery.

Table 4-4 summarizes the discounted compliance cost savings and economic surplus impacts under the proposed action. Compliance cost savings and economic surplus impacts are both inclusive of changes in revenue from gas recovery. For both 3 and 7 percent discount rates, the quantified change in economic surplus is roughly 10 percent greater than the estimated compliance cost savings. The EAV of total surplus is similar for both discount rates.

Table 4-4 Present Value and Equivalent Annualized Value of Compliance Cost Savings and Quantified Changes in Economic Surplus Impacts under the Proposed Reconsideration, from 2027–2050 (millions 2024\$)

	3% Discount Rate		7% Discount Rate	
	<i>Compliance Cost Savings</i>	<i>Change in Economic Surplus</i>	<i>Compliance Cost Savings</i>	<i>Change in Economic Surplus</i>
PV	\$42,000	\$45,000	\$29,000	\$32,000
EAV	\$2,500	\$2,700	\$2,500	\$2,800

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

5 EMISSIONS AND ASSOCIATED HEALTH AND WELFARE IMPACTS

5.1 Introduction

In this section, we present information on the estimated emissions changes and associated health and welfare impacts of the proposed action. The proposed reconsideration standards are projected to increase methane, VOC, and HAP emissions. Methane is a precursor to ozone, so increases in methane emissions may contribute to higher background ozone concentrations. Additionally, emissions of VOC and oxides of nitrogen (NO_x) react to form ozone in the presence of sunlight. Therefore, this rule is expected to affect ozone concentrations. Below, we present quantified estimates of emissions changes, describe the methods used to quantify changes in concentrations of ozone from facilities in the source category and describe impacts of those changes. We discuss the potential health effects of exposure to ozone and other criteria air pollutants as well as HAPs emitted by crude oil and natural gas production associated with this proposed action.

The EPA did not monetize the potential health and welfare impacts of the proposed reconsideration standards (see Section 5.3). Consistent with E.O. 14154 “Unleashing American Energy” (90 FR 8353, January 29, 2025) and the memorandum titled “Guidance Implementing Section 6 of Executive Order 14154, Entitled ‘Unleashing American Energy’,” the EPA did not monetize effects associated with methane emissions changes. For a brief discussion of uncertainties and limitations associated with monetizing effects from methane emissions, see Section 5.4.3 of this RIA.

5.2 Emissions Changes

Table 5-1 summarizes the emissions changes associated with the proposed revisions. The emissions changes are estimated by applying the source-level control efficiencies associated with each applicable control to PTE estimates for those sources and summing up over all operating well sites. Like the temporal patterns observed in Section 4.2 on compliance costs, the estimated impacts are much smaller in magnitude prior to the assumed initial year of EG OOOOc compliance in 2029. Thereafter, the estimated emissions increases are steady over time ranging between 2.5 and 2.8 million short tons of methane per year. The magnitude of the impacts are attributable to two factors: increased emissions resulting from less stringent regulatory

requirements at operating sites, and increased emissions resulting from substantial decreases in site decommissioning (as presented in Figure 3-2 and Table 3-1), as we assume that decommissioned sites do not emit.

As noted in Section 7.4, this RIA depends on several analytic assumptions that impact key values such as changes in emissions. In particular, we cite three reasons that cause EPA to harbor serious doubts that emissions reductions and associated impacts under NSPS OOOOb and OOOOc would be as significant as the estimates presented here suggest. This suggests, in turn, that foregone emissions reductions and associated impacts under this proposal may be less than estimated. First, EPA has not included assumptions about emission reductions that may take place absent the 2024 Final Rule because of state programs for in-state sources and because of voluntary commitments from oil and gas companies. Since these efforts would continue even without the 2024 NSPS OOOOb and EG OOOOc, removing or amending the at-issue regulatory requirements would not impact those emission reductions. In addition, the removal or amendment of the at-issue regulatory requirements could result in new or revised state programs for in-state sources or voluntary commitments that are also not accounted for in this analysis. Second, Section 7.4 notes that one of the places we had the most limited data was on the associated gas requirements established in the NSPS OOOOb and EG OOOOc. If the ratio of gas to oil at relevant sites was lower than EPA assumed in 2024, this would lower the amount of emission reductions achieved via the original 2024 Final Rule even though sources would still need to invest similar amounts to capture that reduced amount of associated gas. Third, because the model does not allow for changing configurations of equipment at individual facilities, it may overestimate emission reductions if the amount of equipment at the site is reduced over time as well production decreases. Note that in analyzing emission reductions from associated gas, EPA assumed that a subset of marginal wells that were far from gathering lines flared achieving 95% reductions while the rest of the wells achieved 100% reduction by routing to a sales line. If units took advantage of some of the additional opportunities to flare in the 2024 Final Rule, or states allowed them to do so in state plans using RULOF considerations, a larger portion of the gas would have been controlled at 95% rather than 100%. This may significantly change the estimated emissions reductions from existing sources subject to EG OOOOc and therefore significantly reduce the foregone emissions reductions estimated for this proposal. EPA is aware of information suggesting that use of the opportunities to flare provided to existing sources in the

2024 Final Rule may be higher than anticipated in the 2024 Final Rule given capacity and infrastructure limitations. EPA intends to further consider these issues and this information, along with information obtained during this rulemaking, to adapt the analysis as appropriate in any final action.

In addition to the limitations noted in Section 7.4, there are at least two other reasons the analysis may overestimate foregone emission reductions resulting from the proposed changes. First, in the 2024 Final Rule EPA did not quantify impacts related to closures of wells due to the requirements that EPA is now proposing to amend. If the proposed amendments are finalized, EPA anticipates less closures compared to the 2024 Final Rule. Unless such closed wells are properly capped, these wells can in fact continue to emit. Not accounting for this in 2024 likely over-estimates the amount of emission reductions the rule is achieving. It likely also underestimates benefits of the proposal because the production from those wells provides benefits to the landowners where the wells are located, the owners/operators of the wells and potentially to states who may be collecting revenue from that production. Second, EPA has not considered the impact of states applying remaining useful life and other factors (RULOF) to the development of their state plans. For example, EPA's action proposes significant changes to marginal well site requirements and associated gas requirements that are the types of provisions states may have considered in their RULOF analysis. To the extent that some of the actions EPA assumed would occur under the 2024 Final Rule would not have actually happened because of States' application of RULOF, this would result in an overestimation of foregone emission reductions.

Finally, an impact that EPA has not yet been able to quantify in either the 2024 analysis or this current analysis is that since the 2024 Final Rule was published, EPA has heard from many stakeholders that for new wells, the operators of which have no option but to route associated gas to a sales line, the associated gas requirements in NSPS OOOOb could lead companies to either have to shut in wells that have been able to route to a sales line but unable to comply or to not drill wells in the first place. Those commenters explained that such provisions could have the effect of significantly discouraging drilling in areas not currently served by gathering lines with adequate capacity to accept gas. It is currently unclear what overall impact that this would have on emissions, cost of compliance, gas and oil production and or gas or oil prices because it is unclear of the extent to which demand for oil/gas would be met by producers

in other areas and if so at what cost, or if some of the demand would not be met at all domestically. Stakeholders noted that at a minimum, this would disproportionately impact smaller producers who are much more dependent on third parties to operate gathering lines and processing plants. EPA intends to further consider these issues as well in an analysis for any final action.

Table 5-1 Annual Emissions Increases under the Proposed Reconsideration and Co-Proposal from 2027–2050

Year	Proposed Reconsideration			Co-Proposal			
	Methane	VOC	HAP	Methane	VOC	HAP	
	(thousand short tons)			(thousand short tons)			
NSPS OOOOb	2027	140	39	5.1	410	120	16
New Wells ^a	2028	170	48	6.3	500	140	19
EG OOOOc pre-compliance activities ^b	2029	2,500	710	95	3200	910	120
NSPS OOOOb and EG OOOOc New and Existing Wells ^c	2030	2,500	720	96	3300	930	120
	2031	2,600	730	97	3400	950	130
	2032	2,600	730	98	3500	980	130
	2033	2,600	740	99	2500	1,000	130
	2034	2,600	740	99	3600	1,000	140
	2035	2,700	750	100	3700	1,000	140
	2036	2,700	750	100	3800	1,100	140
	2037	2,700	760	100	3800	1,100	140
	2038	2,700	760	100	3900	1,100	150
	2039	2,700	760	100	3900	1,100	150
	2040	2,700	760	100	4000	1,100	150
	2041	2,700	770	100	4000	1,100	150
	2042	2,700	770	100	4100	1,200	150
	2043	2,800	780	100	4200	1,200	160
	2044	2,800	780	100	4200	1,200	160
	2045	2,800	780	100	4300	1,200	160
	2046	2,800	790	110	4400	1,200	160
	2047	2,800	790	110	4400	1,200	170
	2048	2,800	790	110	4500	1,300	170
	2049	2,800	790	110	4500	1,300	170
2050	2,800	800	110	4600	1,300	170	
Total	60,000	17,000	2,300	88,000	25,000	3,300	

Note: Values rounded to two significant figures. Totals may not appear to add correctly due to rounding. Positive values represent the increase in emissions over the baseline.

^a Under the 2024 Final Rule, in 2027 and 2028, only new sources covered by NSPS OOOOb would have been required to make emission reductions; EG OOOOc provided time for states to develop state plans and time for sources to come into compliance with the provisions of those state rules.

^b While compliance for existing sources is not required until January of 2030, it is not possible for sources to take necessary action to instantaneously comply with a rule, especially when there are tens of thousands of sources across the country. Given the temporal granularity of EPA's modeling tools, this is represented by assuming all of the controls that would be installed between the finalization of state plans and the compliance date come on-line on January 1, 2029. In reality, these controls would be installed in a rolling fashion such that less would exist in the beginning of January 2029 and more would be in place by the end of 2029. This suggests that EPA's modeling simplification is almost certainly an overestimate of emission reductions in 2029.

^c With the caveats above that there are several reasons that foregone emission reductions may have been overestimated, 2030 and beyond represent foregone emission reductions when both the proposed revisions to the 2024 Final Rule issues in October 2026 and the 2025 IFR providing an extension to state plans for state plan submittals are accounted for.

5.3 Air Quality Modeling of Ozone Concentrations Due to VOC Emissions Changes

This proposed action is projected to increase 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 NO_x, react in the atmosphere in the presence of sunlight. In urban areas, compounds representing all classes of VOC can be important for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in some non-urban vegetated areas (U.S. EPA, 2013). Recent observational and modeling studies have found that VOC emissions from oil and natural gas operations can impact ozone levels (Helmig, 2020; Kembell-Cook et al., 2010; Lindaas et al., 2019; Lyu et al., 2021; McDuffie et al., 2016; Pozzer et al., 2020; Reddy, 2023; Tzompa-Sosa & Fischer, 2021). Methods used for determining air quality changes presented in this section have previously been used in the RIAs from multiple previous proposed and final rules (U.S. EPA, 2019b, 2020b, 2020c, 2021, 2022a, 2023d, 2023e).

As described above, this proposed action influences the level of VOCs, a precursor to ground-level ozone formation, emitted in the atmosphere. The VOC emissions changes associated with the proposed standards are presented in Section 4.2. A map of state-level VOC emissions increases used in the creation of the ozone surfaces is provided in Figure 5-1.

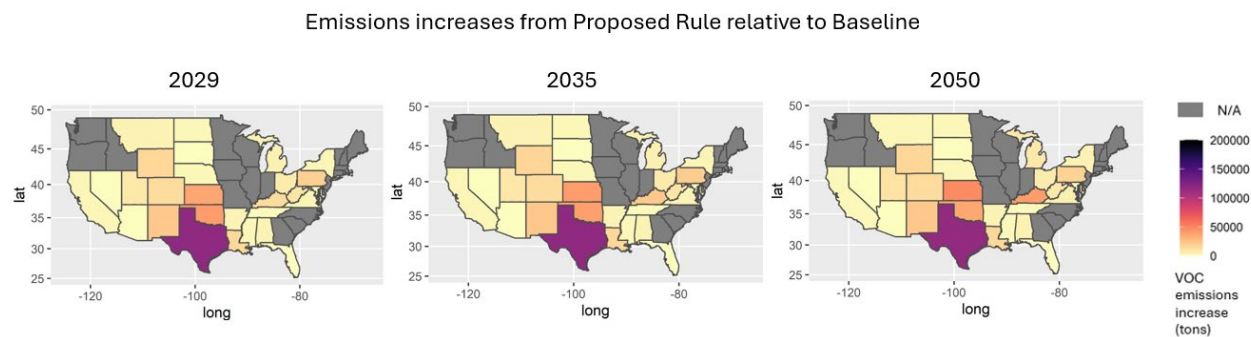


Figure 5-1 Map of State-level ozone season (Apr.-Sept.) VOC Emissions Increases (tons) under the Proposed Reconsideration Scenario relative to the Baseline Scenario in 2029 (left panel), 2035 (center panel), and 2050 (right panel)

The EPA used air quality modeling to estimate changes in summertime ozone concentrations that may result from the VOC emissions increases in the proposed standards relative to the baseline in three years of analysis.⁵⁶ Gridded spatial fields of April through September seasonal average 8-hour daily maximum (MDA8) ozone (AS-MO3) concentrations representing the baseline and the proposed standards were derived from CAMx source apportionment modeling in combination with the VOC emissions described in Section 3.3.2 of this RIA and shown in Figure 5-1. These ozone gridded spatial fields cover all locations in the contiguous U.S.

Figure 5-2 shows the geographical distribution of summertime ozone changes in the proposed reconsideration relative to the baseline in the three years of analysis. The basic methodology for determining air quality changes is the same as that used in the RIAs from multiple previous rulemakings (U.S. EPA, 2019b, 2020b, 2020c, 2021, 2022a, 2023d, 2023e). U.S. EPA (2026) provides additional details on the air quality modeling and the methodologies EPA used to develop gridded spatial fields of summertime ozone concentrations for this analysis.

⁵⁶ The air quality modeling was conducted using emissions from the year 2022. The ozone surfaces reflecting the baseline and proposed rule in 2029, 2035, and 2050 adjust ozone impacts from 2022 oil and gas VOC sources to reflect expected baseline and proposed rule case VOC emissions from those sources in each of those years. Emissions from all other sources are held constant at 2022 levels. Impacts of methane emissions changes on ozone are not simulated in this analysis.

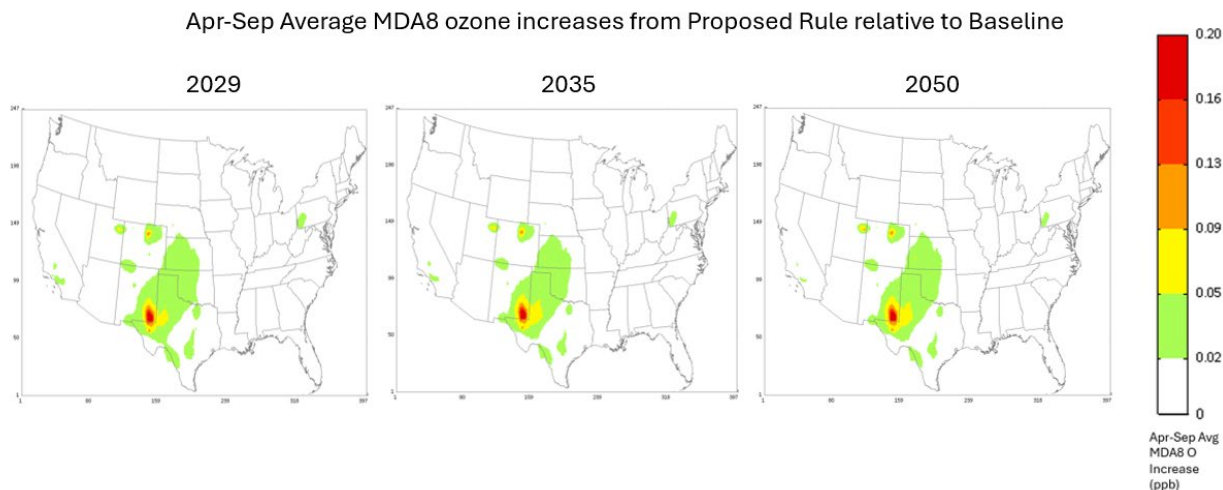


Figure 5-2 Map of Modeled Changes in April to September MDA8 Ozone Concentrations (ppb) Calculated as the Proposed Reconsideration Scenario Minus the Baseline Scenario in 2029 (left panel), 2035 (center panel), and 2050 (right panel).

5.4 Criteria Pollutant Health and Welfare Effects

Historically, the EPA estimated the monetized benefits of avoided PM_{2.5}- and ozone-related impacts, which accounted for most, if not all, of the monetized benefits of many air regulations—even when the regulation was not regulating PM_{2.5} or ozone – within Regulatory Impact Analyses. The Office of Management and Budget (OMB), in its annual report of the Benefits and Costs of Federal Regulations, routinely provides estimates that the monetized benefits from reducing PM_{2.5} and/or ozone exceed hundreds of millions or even billions of dollars and result in most of the monetized benefits from Federal regulations.

In previous Regulatory Impact Analyses (RIAs), the Agency’s approach to estimating the impacts to human health of the changes in concentrations of ozone and PM_{2.5} relied substantially on information from the Integrated Science Assessments for ozone and particulate matter (e.g., (U.S. EPA, 2020a), (U.S. EPA, 2019a). These documents synthesize the toxicological, clinical, and epidemiological evidence to determine whether PM and ozone are causally related to an array of adverse human health outcomes associated with either acute (e.g., hours or days-long) or chronic (e.g., years-long) exposure; for each outcome, the ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship or not likely to be a causal relationship. The ISAs reflect the Agency most up-to-date evaluation of the strength and limitations of the available scientific evidence, and clearly identify

the health and welfare endpoints for which the evidence is strongest. The Agency continues to focus on these endpoints in considering how regulatory actions may impact public health and welfare. Historically, the Agency has estimated the incidence of air pollution effects for those health endpoints that the ISA classified as either causal or likely-to-be-causal and these endpoints are shown in Table 5-1. The table below omits welfare effects such as acidification and nutrient enrichment.

Table 5-2 Health Effects of Ambient Ozone and PM_{2.5}

Category	Effect	Causal/Likely-to-be-causal	More Information
Premature mortality from exposure to PM _{2.5}	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age 65-99 or age 30-99)	✓	PM ISA
	Infant mortality (age <1)	✓	PM ISA
Nonfatal morbidity from exposure to PM _{2.5}	Heart attacks (age > 18)	✓	PM ISA
	Hospital admissions—cardiovascular (ages 65-99)	✓	PM ISA
	Emergency department visits—cardiovascular (age 0-99)	✓	PM ISA
	Hospital admissions—respiratory (ages 0-18 and 65-99)	✓	PM ISA
	Emergency room visits—respiratory (all ages)	✓	PM ISA
	Cardiac arrest (ages 0-99; excludes initial hospital and/or emergency department visits)	✓	PM ISA
	Stroke (ages 65-99)	✓	PM ISA
	Asthma onset (ages 0-17)	✓	PM ISA
	Asthma symptoms/exacerbation (6-17)	✓	PM ISA
	Lung cancer (ages 30-99)	✓	PM ISA
	Allergic rhinitis (hay fever) symptoms (ages 3-17)	✓	PM ISA
	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	✓	PM ISA
	Other respiratory effects	✓	PM ISA
	Other nervous system effects	✓	PM ISA
	Cancer	✓	PM ISA
	Reproductive and developmental effects	—	PM ISA
	Metabolic effects	—	PM ISA
Mortality from exposure to ozone	Premature respiratory mortality based on short-term study estimates (0-99)	✓	Ozone ISA
	Premature respiratory mortality based on long-term study estimates (age 30–99)	✓	Ozone ISA
Nonfatal morbidity from exposure to ozone	Hospital admissions—respiratory (ages 0-99)	✓	Ozone ISA
	Emergency department visits—respiratory (ages 0-99)	✓	Ozone ISA
	Asthma onset (0-17)	✓	Ozone ISA
	Asthma symptoms/exacerbation (asthmatics age 2-17)	✓	Ozone ISA
	Allergic rhinitis (hay fever) symptoms (ages 3-17)	✓	Ozone ISA
	Minor restricted-activity days (age 18–65)	✓	Ozone ISA
	School absence days (age 5–17)	✓	Ozone ISA
	Metabolic effects (e.g., diabetes)	✓	Ozone ISA

For regulatory analyses, the Agency estimated changes in health effects in response to modeled air quality changes for each health endpoint identified as causal or likely-to-be-causal in Table 5-1. The environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) software program was used to quantify counts of premature deaths and illnesses attributable to photochemical modeled changes in annual mean PM_{2.5} and summer season

average ozone. This approach to estimating health impacts involved two major steps: (1) developing spatial fields of air quality across the U.S. for the baseline and regulatory scenarios using nationwide photochemical source apportionment modeling and related analyses; and (2) using these spatial fields in BenMAP-CE to quantify selected endpoints under each scenario and each year as compared to the baseline in that year while accounting for the changes in population size, income growth, and baseline incidence and prevalence rates.

Figure 5-3 summarizes the key data inputs and modeling steps for estimating the health impacts of a regulatory impact analysis using PM_{2.5} inputs as an example.

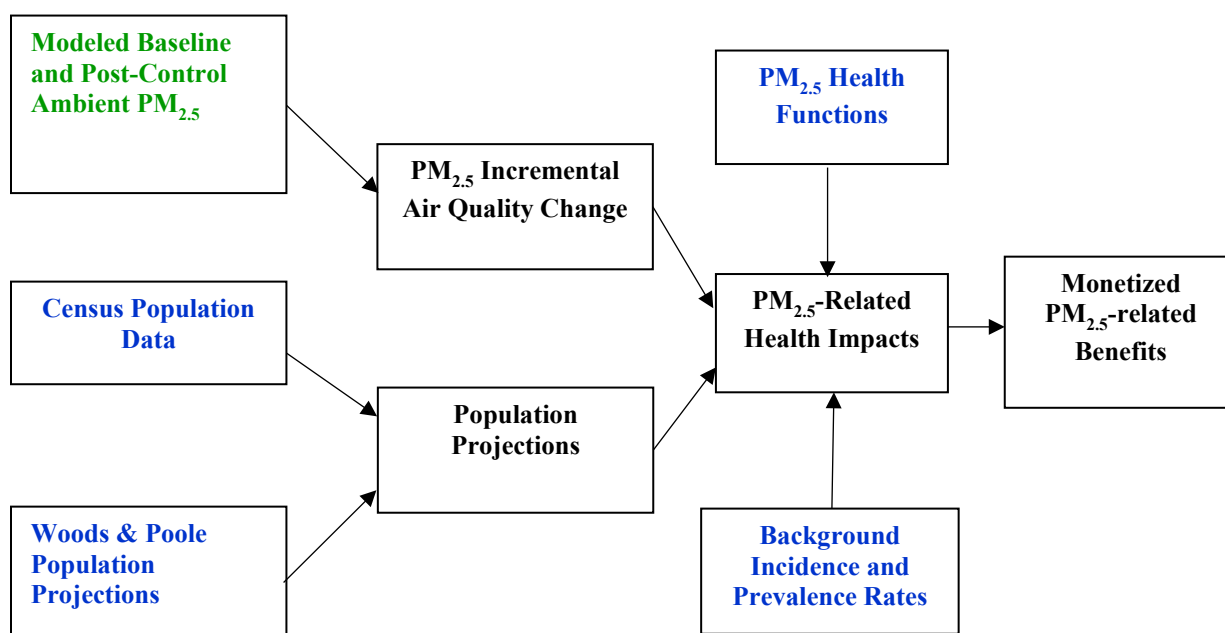


Figure 5-3 Data Inputs and Outputs for the BenMAP-CE Model Using PM_{2.5} as an Example

As the diagram above illustrates, the approach for estimating PM_{2.5} and O₃ benefits included health effect risk estimates from epidemiologic studies, population data, population growth estimates, economic data for monetizing risk reductions, and assumptions regarding the future state of the world (e.g., on-the-books regulations). Each of these inputs has unique uncertainties associated with it. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits. Where possible, the EPA in the past has attempted to quantitatively assess uncertainty in each input parameter. In some cases, quantitative analysis has not been possible due to lack of data, so

the Agency instead characterized 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 lacked the data to perform either a quantitative uncertainty analysis or sensitivity analysis.

Throughout prior regulatory impact analyses, the EPA acknowledged these significant uncertainties around input parameters and employed various techniques for characterizing the resulting uncertainty in estimates of regulatory impacts. For example, the Agency has estimated the fraction of avoided health effects occurring at various concentration ranges, conducted sensitivity analyses, and employed alternate concentration-response assumptions to show how much estimates could vary depending on which assumptions and inputs were used in primary estimates vs. sensitivity estimates.

Chapter 6 of the EPA Health Benefits TSD, Estimating PM_{2.5}- and Ozone-Attributable Health Benefits: 2024 Update, details our approach to characterizing uncertainty associated with the estimation of PM_{2.5} and O₃ benefits in both quantitative and qualitative terms (U.S.EPA, 2024). Some of the key types of uncertainty highlighted in this chapter include:

- Statistical uncertainty around the risk estimate
- Uncertainty around low concentration exposures and the potential for thresholds
- Uncertainty in exposure estimates
- Co-pollutant confounding
- Confounding by other individual risk factors
- Effect modification
- Application of risk estimates to other locations and populations
- Uncertainties regarding at-risk populations
- Baseline incidence rate uncertainties
- Economic valuation estimate uncertainties (e.g. income elasticity of willingness to pay, statistical estimates of VSL, Alzheimer's and Parkinson's onset lifetime costs)
- Unquantified uncertainties (e.g. causality determination, estimating and assigning exposures in epidemiology studies, risk attributable to long-term and short-term exposures, shape of the concentration-response relationship)

Despite substantial investments by the EPA in approaches to characterizing uncertainties, the regulatory impact analyses have still tended to focus on point estimates for PM_{2.5} and ozone-

related benefits. Frequently, the Agency has utilized more than one epidemiologic study to estimate mortality impacts because these estimates drive overall benefits for a given regulatory action due to the large monetary value assigned to such impacts. Risk estimates using the top epidemiologic studies sometimes differ by a factor of two or more. Presenting multiple estimates drawn directly from the primary literature is one way to convey the prevailing uncertainty. While this leads to an estimated range of benefits, it is not a range that reflects the true uncertainties in the underlying parameters supporting each study, either for mortality or for other effects. Because of the significant impacts of environmental regulations on the U.S. economy, it is essential that the Agency have confidence in the estimated benefits of an action, and their underlying uncertainties, prior to utilizing these estimates in a regulatory context.

A 2024 Scientific Advisory Board reviewed EPA's methods for estimating the health effects of PM_{2.5} and clearly and repeatedly recommended that EPA improve its approach to characterizing and presenting the uncertainty in estimating the health effects of PM_{2.5}.⁵⁷ A Tier 1 SAB recommendation was that the EPA present a single probabilistic mortality estimate based on pooled risk estimates with associated uncertainty ranges rather than present multiple estimates of mortality outcomes from the epidemiologic studies. EPA was encouraged to explore meta-analysis methods or other forms of information synthesis, and support research and development of modified methods as needed.

The OMB "2017 Report to Congress on the Benefits and Costs of Federal Regulations" listed six key assumptions underpinning PM_{2.5} health effect estimation which introduce substantial uncertainties in the health effect estimates:⁵⁸

1. That inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis;

⁵⁷ U.S. EPA. (2024). *Review of BenMAP and Benefits Methods*. (EPA/SAB/24/003). Washington DC: U.S. Environmental Protection Agency. Available at: https://sab.epa.gov/ords/sab/r/sab_apex/sab/advisoryactivitydetail?p18_id=2617&clear=18&session=15054897040198#report.

⁵⁸ See the OMB's "2017 Report to Congress on Benefits and Costs of Federal Regulations and Agency Compliance with the Unfunded Mandates Reform Act" for a fuller discussion on uncertainties. Available at https://trumpwhitehouse.archives.gov/wp-content/uploads/2019/12/2019-CATS-5885-REV_DOC-2017Cost_BenefitReport11_18_2019.docx.pdf.

2. That the concentration-response function for fine particles and premature mortality is approximately linear, even for concentrations below the levels established by the NAAQS;
3. That all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality;
4. That the forecasts for future emissions and associated air quality modeling accurately predict both the baseline (state of the world absent a rule) and the air quality impacts of the rule being analyzed;
5. That BPT approaches, when used to estimate benefits, are based on regional or national-level analysis that may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors; and
6. That the estimated value of mortality risk reductions is an accurate reflection of what people would be willing to pay for incremental reductions in mortality risk from air pollution exposure, and that these values are constant across the life-cycle.

To the extent that any of these assumptions is incorrect, the benefit estimates will change, though the magnitude and direction of change are not known with certainty. The EPA is interested in improving understanding in each of these six areas. EPA understands that additional research is needed, and will begin to develop approaches that reduce these uncertainties. The EPA will seek peer review for new methods developed from this work consistent with the OMB's Peer Review Guidance.⁵⁹

In particular, the EPA is interested in reevaluating the validity of the approach for estimating the benefits of air quality improvements relative to the National Ambient Air Quality Standards (NAAQS) for PM_{2.5} and ozone. These standards, which have been set at a level which the Administrator judges to be requisite to protect public health or welfare with an adequate margin of safety, are widely understood to represent the divide between clean air and air with an unacceptable level of pollution. Even in instances where an assumption is found to be justified

⁵⁹ OMB (2005). *Memorandum M-05-03, Memorandum for the Heads of Executive Departments and Agencies: Issuance of OMB's Final Information Quality Bulletin for Peer Review*. Available at: <https://www.federalregister.gov/documents/2005/01/14/05-769/final-information-quality-bulletin-for-peer-review>.

based on scientific evidence, the EPA is interested in reevaluating its approach to characterizing and communicating underlying uncertainty to the public.

In the past, the EPA has explored a variety of approaches to shed light on how the estimated benefits of an action relate to the level of the NAAQS. For example, in estimating PM benefits, the Agency has employed techniques such as cutpoint analyses and Lowest Measured Level analyses, noting that we are most confident in the magnitude of the risks we project at PM_{2.5} concentrations that coincide with the bulk of the observed PM_{2.5} concentrations in the epidemiological studies that are used to estimate the benefits (Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, Section 4.4.4, p. 4-26). However, such approaches address only a few of the sources of uncertainty that influence PM-related air quality benefits.

The limitations of reduced-form approaches, such as the BPT approach are even more pronounced than photochemical modeling/BenMAP-CE approaches due to: 1) the compounding effects of emissions reductions typically occurring across many geographic areas simultaneously, with varying proximity to population centers; 2) differing atmospheric transformation pathways for nitrous oxides (NO_x), volatile organic compounds (VOCs), and secondary PM_{2.5}; and 3) region-specific photochemical and meteorological conditions. Using a national BPT estimate implicitly assumes uniform marginal health benefits for each ton of reduced emissions, an assumption not supported given heterogeneity in exposure patterns and atmospheric chemistry. As more areas achieve or maintain attainment with the NAAQS, the uncertainties associated with low-concentration health effects grow, and marginal benefits become more difficult to characterize with precision.

Therefore, it may be appropriate for the EPA to separate exposures and impacts above the level of the standard from those occurring at lower ambient concentrations. The EPA will investigate this prior to estimating these impacts in a regulatory analysis even for informational purposes.

5.4.1 Ozone-Related Health Effects

Following a comprehensive review of toxicological, clinical, and epidemiological evidence, the Integrated Science Assessment for Ozone and Related Photochemical Oxidants

(Ozone ISA) (U.S. EPA, 2020a) found both short-term (i.e., less than one month) and long-term (i.e., one month or longer) ozone exposure to be related to an array of adverse human health effects. For each effect, the Ozone ISA reports relationships to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship, or not likely to be a causal relationship. This assessment is based on the body of scientific evidence which can include observational human studies, experimental human exposure studies, animal model studies, and mechanistic studies.

The Ozone ISA found short-term exposure to ozone to be causally related to respiratory effects, including respiratory mortality, and likely to be causally related to metabolic effects. For short-term exposure, evidence was suggestive of a causal relationship for cardiovascular and nervous system effects as well as total mortality. The Ozone ISA reported that long-term exposure to ozone is likely-to-be-causally related to respiratory effects, including respiratory mortality. Evidence on metabolic, cardiovascular, reproductive, and nervous system effects as well as total mortality was suggestive of a causal relationship with long-term ozone exposure.

When adequate data and resources are available, the EPA has generally quantified health effects which the Ozone ISA classified as causally related or likely-to-be-causally related to short- or long-term ozone exposure. Health effects classified as suggestive-of-causality or weaker have not historically been quantified. Historically quantified health effects include premature respiratory mortality, hospital admissions and emergency department visits, asthma onset and related symptoms (chest tightness, cough, shortness of breath, and wheeze), allergic rhinitis symptoms, as well as restricted activity days and school absences. The EPA did not quantify or monetize the benefits or disbenefits associated with changes in the incidence of the listed health effects of this rule.

5.4.2 Ozone-Related Welfare Effects

Due to operational constraints and data limitations, most benefits analyses focus on human health effects expected to occur because of changes in pollutant concentrations resulting from the rulemaking; however, changes in air pollution may also impact welfare. The Clean Air Act encourages consideration of the welfare effects of air pollutants, which it defines as including, but not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and

hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other pollutants (42 U.S.C. §7602(h)). In this section, we provide qualitative discussions of select welfare effects.

5.4.2.1 Vegetation and Ecosystem 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, changes to species composition, and changes in ecosystems and associated ecosystem services (U.S. EPA, 2020a).

5.4.2.2 Animal Welfare Effects

While effects can be context- and species-specific, a large body of scientific evidence links ozone exposure to health effects in animals. When exploring environmental pathways through which environmental effects of ozone may impact animals, the Ozone ISA found a likely-to-be-causal relationship between ambient ozone concentrations and alterations of herbivore growth and reproduction (U.S. EPA, 2020a, Girón-Calva et al. 2016, Habeck and Lindroth, 2013, Hong et al., 2016, Ueno et al., 2016). In addition, many animal toxicological studies served as evidence for determining the causality of relationships between human exposure to ozone and human health effects, including respiratory and metabolic effects. The Ozone ISA states, “A large body of experimental animal toxicological studies demonstrates (short- and long-term) ozone-induced changes in measures of lung function, inflammation, increased airway responsiveness, and impaired lung host defense” (U.S. EPA, 2020a). Additionally, animal studies report relationships between short-term ozone exposure and metabolic effects in various stocks and strains of animals across multiple laboratories (U.S. EPA, 2020a, Gordon et al., 2017, Miller et al., 2015, Ying et al., 2016,).

5.4.3 Effects From Changes in Methane Emissions

Methane also contributes to the chemical formation of ozone (U.S. EPA, 2020a). Methane is less reactive and has a longer atmospheric lifetime than other organic ozone precursors, and therefore primarily contributes to “background” levels of ozone, rather than localized ozone production. 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 NOX 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). Increasing methane emissions will therefore contribute to global background ozone concentrations that contribute to the incidence of ozone-related health effects (USGCRP, 2018). We do not quantify or monetize these health effects. We also do not quantify or monetize the climate-related effects of increased methane emissions.

There are significant uncertainties related to the monetization of GHGs that include, but are not limited to: the magnitude of the change in climate due to a change in GHG emissions; the relationship between changes in the climate and the economy and therefore, the resulting economic impacts; future economic and population growth which are important for estimating vulnerability, willingness to pay to avoid impacts, and the ability to adapt to future changes; future technological advancements that would reduce vulnerability and impacts; the share of impacts from GHG emissions that affect citizens and residents of the United States; and the appropriate discount rates to use when discounting in an intergenerational context. Consistent with the memorandum titled “Guidance Implementing Section 6 of Executive Order 14154, Entitled ‘Unleashing American Energy’,” the EPA did not quantify and monetize impacts from changes in GHG emissions for this proposed action. Monetizing these impacts could potentially result in flawed decision-making due to overreliance on highly uncertain values.

5.5 Hazardous Air Pollutants (HAP) Impacts

This proposed rule is expected to increase emissions of HAP. The main HAP that could be affected by this rule include n-hexane, benzene, toluene, ethylbenzene, xylene, and methanol. Exposure to these HAPs have known acute (short-term) and chronic (long-term) adverse health effects, including neurological- and respiratory-related morbidities and cancer risks. We provide a more robust qualitative discussion of health effects associated with exposure to HAP affected by this rule in the March 2024 Final Rule RIA.⁶⁰ Due to methodology and data limitations, we did not attempt to quantify and monetize the health effects associated with HAP emitted from sources subject to this rule. Quantifying and monetizing the economic value of reducing the risk of cancer effects due to HAP exposure is made difficult by the frequent lack of a central estimate of cancer risk as well as estimates of the value of an avoided case of cancer, fatal and non-fatal (LaPenta et al., 2024). Assessing population incidence of non-fatal health effects and risk from threshold carcinogens also poses unique challenges (National Research Council, 2009).

⁶⁰ See Section 3.8 of the March 2024 Final Rule RIA which can be found in the docket here: <https://www.regulations.gov/document/EPA-HQ-OW-2022-0114-3268>.

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6 ECONOMIC IMPACTS AND DISTRIBUTIONAL ANALYSIS

6.1 Oil and Natural Gas Market Impact Analysis

The market equilibrium framework described in Section 3 allows us to estimate changes to commodity prices and total production resulting from different regulatory options. The market impact analysis is intended to provide some information on the economic impacts of the proposed reconsideration and to inform the EPA’s response to E.O. 13211 “Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use.”

Table 6-1 presents the reference levels of domestic crude oil and natural gas production and prices used in the model. Reference levels of U.S. crude oil production, dry gas production, WTI crude oil prices, and Henry Hub natural gas prices are derived from AEO2025 data series.⁶¹ Production includes offshore production, which is treated as exogenous in the model. Oil production is presented in barrels (bbl) per year, and gas production is presented in trillion cubic feet (Tcf) per year.

⁶¹ See Section 3.2 of the model methodology TSD for details on how AEO2025 Reference Case production projections were used in the calibration of the model used in this analysis.

Table 6-1 Reference Levels of Crude Oil and Natural Gas Production and Prices Used in Market Analysis from 2027–2050^a

Year	Crude Oil		Natural Gas	
	Production (Bbbl/year)	Price (2024\$/bbl)	Production (Tcf/year)	Price (2024\$/Mcf)
2027	5.1	78.23	39.1	2.72
2028	5.1	77.82	40.2	2.83
2029	5.1	77.65	40.9	3.00
2030	5.1	78.03	41.5	3.19
2031	5.0	78.22	41.5	3.35
2032	4.9	77.21	43.4	3.84
2033	4.9	79.36	43.2	4.25
2034	4.8	79.65	42.8	4.5
2035	4.7	80.09	42.4	4.59
2036	4.7	80.37	41.9	4.59
2037	4.6	81.35	41.3	4.53
2038	4.5	81.58	41.0	4.47
2039	4.4	82.10	40.9	4.40
2040	4.4	82.70	41.2	4.43
2041	4.4	83.13	41.6	4.51
2042	4.4	82.86	41.8	4.58
2043	4.3	84.76	41.9	4.72
2044	4.3	83.68	41.9	4.81
2045	4.2	84.66	41.7	4.87
2046	4.2	85.09	41.9	4.96
2047	4.2	87.76	41.9	5.01
2048	4.1	88.10	42.0	5.01
2049	4.1	88.66	42.1	4.98
2050	4.1	89.27	42.0	4.98

^a Reference U.S. crude oil and natural gas production and prices drawn from the projected WTI and the EIA's AEO2025 Henry Hub Spot Price, respectively. We present the price of natural gas in 2024\$/MMBtu; to convert from 2024\$/MMBtu to 2024\$/Mcf, multiply by 1.037.

The estimated market impacts are summarized in Table 6-2 and Table 6-3 for the proposed reconsideration and co-proposal, respectively. In general, we estimate increases in production and decreases in prices for both commodities. Notably, the estimated impacts on production and prices are small in magnitude for both markets, typically a fraction of a percent in all years. This result is not unexpected, given that the proposed action focuses on marginal production sites, whose production represents a relatively small portion of domestic production.

**Table 6-2 Estimated Crude Oil and Natural Gas Production and Price Changes under
the Proposed Reconsideration from 2027–2050**

Year	Crude Oil				Natural Gas			
	U.S. Production		U.S. Prices		U.S. Production		U.S. Prices	
	MMbbl/year	%	\$/bbl	%	Bcf/year	%	\$/Mcf	%
2027	4.7	0.09%	-0.11	-0.14%	25	0.07%	-0.003	-0.11%
2028	5	0.10%	-0.11	-0.14%	33	0.08%	-0.004	-0.15%
2029	9.5	0.19%	-0.22	-0.28%	67	0.16%	-0.0085	-0.29%
2030	9.1	0.18%	-0.21	-0.27%	63	0.15%	-0.0085	-0.27%
2031	9.2	0.18%	-0.21	-0.27%	60	0.14%	-0.0085	-0.26%
2032	9.3	0.19%	-0.21	-0.27%	63	0.14%	-0.010	-0.26%
2033	9.1	0.19%	-0.22	-0.27%	61	0.14%	-0.011	-0.26%
2034	9.2	0.19%	-0.22	-0.27%	60	0.14%	-0.011	-0.27%
2035	9.2	0.20%	-0.22	-0.27%	59	0.14%	-0.012	-0.27%
2036	9.2	0.20%	-0.22	-0.27%	58	0.13%	-0.012	-0.26%
2037	9.1	0.20%	-0.22	-0.27%	55	0.13%	-0.011	-0.26%
2038	9	0.20%	-0.22	-0.27%	54	0.13%	-0.011	-0.26%
2039	9	0.20%	-0.22	-0.27%	55	0.13%	-0.011	-0.26%
2040	9	0.21%	-0.23	-0.27%	57	0.14%	-0.011	-0.27%
2041	9	0.21%	-0.23	-0.27%	60	0.14%	-0.012	-0.28%
2042	9	0.21%	-0.23	-0.27%	62	0.14%	-0.012	-0.29%
2043	9.1	0.21%	-0.23	-0.27%	63	0.15%	-0.013	-0.29%
2044	9.1	0.21%	-0.23	-0.27%	63	0.15%	-0.013	-0.29%
2045	9.1	0.22%	-0.23	-0.27%	64	0.15%	-0.013	-0.29%
2046	9.1	0.22%	-0.24	-0.28%	65	0.15%	-0.014	-0.30%
2047	9.1	0.22%	-0.24	-0.27%	65	0.15%	-0.014	-0.30%
2048	9	0.22%	-0.24	-0.27%	65	0.15%	-0.014	-0.30%
2049	8.9	0.22%	-0.24	-0.27%	66	0.15%	-0.014	-0.30%
2050	8.8	0.21%	-0.24	-0.26%	67	0.15%	-0.014	-0.31%

Table 6-3 Estimated Crude Oil and Natural Gas Production and Price Changes under the Co-Proposal from 2027–2050

Year	Crude Oil				Natural Gas			
	U.S. Production		U.S. Prices		U.S. Production		U.S. Prices	
	Bbbl/year	%	\$/bbl	%	Bcf/year	%	\$/Mcf	%
2027	5.3	0.10%	-0.12	-0.15%	8	0.02%	-0.001	-0.04%
2028	5.6	0.11%	-0.13	-0.16%	11	0.03%	-0.001	-0.05%
2029	10	0.20%	-0.23	-0.30%	25	0.06%	-0.0032	-0.11%
2030	9.8	0.19%	-0.23	-0.29%	19	0.05%	-0.0026	-0.08%
2031	9.9	0.20%	-0.23	-0.29%	14	0.03%	-0.0019	-0.06%
2032	10	0.20%	-0.23	-0.29%	14	0.03%	-0.002	-0.06%
2033	9.9	0.20%	-0.23	-0.29%	9	0.02%	-0.002	-0.04%
2034	10	0.21%	-0.24	-0.29%	4	0.01%	-0.001	-0.02%
2035	10	0.21%	-0.24	-0.30%	1	0.00%	0.000	0.00%
2036	9.9	0.21%	-0.24	-0.30%	-4	-0.01%	0.001	0.02%
2037	9.8	0.22%	-0.24	-0.30%	-9	-0.02%	0.002	0.04%
2038	9.8	0.22%	-0.24	-0.30%	-13	-0.03%	0.003	0.06%
2039	9.8	0.22%	-0.24	-0.30%	-14	-0.03%	0.003	0.07%
2040	9.8	0.22%	-0.25	-0.29%	-13	-0.03%	0.003	0.06%
2041	9.7	0.22%	-0.25	-0.29%	-12	-0.03%	0.002	0.06%
2042	9.8	0.23%	-0.25	-0.30%	-12	-0.03%	0.003	0.06%
2043	9.8	0.23%	-0.25	-0.30%	-13	-0.03%	0.0028	0.06%
2044	9.9	0.23%	-0.25	-0.30%	-16	-0.04%	0.0034	0.07%
2045	9.9	0.23%	-0.25	-0.30%	-19	-0.04%	0.004	0.09%
2046	10	0.24%	-0.26	-0.30%	-19	-0.05%	0.0042	0.09%
2047	9.9	0.24%	-0.26	-0.30%	-22	-0.05%	0.0047	0.10%
2048	9.8	0.24%	-0.26	-0.30%	-25	-0.06%	0.0054	0.11%
2049	9.7	0.24%	-0.26	-0.29%	-27	-0.06%	0.0058	0.12%
2050	9.6	0.23%	-0.26	-0.29%	-29	-0.07%	0.0062	0.13%

We use the results in Table 6-2 and Table 6-3 to evaluate whether the proposed action is likely to have a significant effect on the supply, distribution, or use of energy as defined by E.O. 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.’”⁶² With respect to crude oil production, the guidance indicates that a regulatory action produces a significant adverse effect if it is expected to produce reductions in crude oil supply in excess of 20 million barrels per year.

⁶² See <https://www.whitehouse.gov/wp-content/uploads/2021/01/M-21-12.pdf>.

With respect to natural gas production, the guidance indicates that a regulatory action produces a significant adverse effect if it reduces natural gas production in excess of 40 million Mcf per year.⁶³ Based on our analysis, this proposed action does not constitute a significant energy action as it is expected, on net, to result in annual increases in both oil and natural gas production.

6.2 Employment Impacts of Environmental Regulation

This section discusses potential employment impacts related to the proposed action. Employment impacts of environmental regulations are generally composed of a mix of potential declines and gains in different areas of the economy over time. Regulatory employment impacts can vary across occupations, regions, and industries; by labor and product demand and supply elasticities; and in response to other labor market conditions. Isolating such impacts is a challenge, as they are difficult to disentangle from employment impacts caused by a wide variety of ongoing, concurrent economic changes.

Economic theory indicates that the effect of environmental regulation on labor demand is difficult to predict ex-ante: emissions sources that face increased costs to comply with a new environmental regulation may reduce output, which means fewer inputs are required than previously, including labor; they may make changes to their production process in a way that favors or disfavors labor compared to other inputs such as capital; and they may need labor to engage in new compliance activities. As a result, emissions sources affected by environmental regulation may increase their demand for some types of labor, decrease demand for other types, or may even absorb compliance costs in a way that minimizes effects on labor (Berman and Bui, 2001; Deschenes, 2018; Morgenstern et al., 2002). To study the impacts of environmental regulation on firms' demand for labor empirically, a growing literature has compared employment levels at facilities subject to an environmental regulation to employment levels at similar facilities not subject to that environmental regulation; some studies find no employment effects, and others find significant differences. Employment effects have been found to manifest in different ways across affected emissions sources, such as shifting workers across sources

⁶³ The 2021 E.O. 13211 guidance memo states that the natural gas production decrease that indicates the regulatory action is a significant energy action is 40 Mcf per year. Because this is a relatively small amount of natural gas and previous guidance from 2001 indicated a threshold of 25 million Mcf, we assume the 2021 memo was intended to establish 40 million Mcf as the indicator of an adverse energy effect. See <https://www.whitehouse.gov/wp-content/uploads/2017/11/2001-M-01-27-Guidance-for-Implementing-E.O.-13211.pdf>.

owned by the same firm, wage changes, job loss, and reduced hiring (e.g., Ferris et al., 2014; Curtis, 2018). A recent discussion of labor demand channels and a review of empirical literature is presented in Gray et al. (2023).

Considered across the economy and over the long run, environmental regulation is expected to cause a shift of workers among employers rather than affect the general employment level (Arrow et al. 1996, Hafstead and Williams, 2020). Employers facing a new environmental rule are more likely to see reduced employment due to cost pressure, while a movement of labor can occur towards jobs associated with pollution control or production techniques unimpacted by the regulation. Even if net impacts on employment are small after long-run market adjustments to full employment across the economy, regulatory actions move workers in and out of locations, jobs and industries, which has an important distributional impact (U.S. OMB, 2015; Walker, 2013). Transitional job losses in the near term may also have greater 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 in Section 4.2, the proposed reconsideration standards are projected to reduce compliance costs for operators in the oil and natural gas production industries. A substantial share of the changes in costs (e.g., for planning, operation, and maintenance of equipment associated with product recovery and managing equipment leaks) may be associated with labor inputs, and therefore could impact employment levels in the directly regulated sector or sectors that provide pollution control services. Additionally, as indicated by the potential impacts on oil and natural gas markets discussed in Section 6.1, the additional reconsideration standards 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 due to quantity effects in directly regulated sectors and sectors that consume oil and natural gas products. The EPA continues to explore the relevant theoretical and empirical literature and to seek public comments to ensure that the way the EPA characterizes the employment effects of its regulations is reasonable and informative

6.3 References

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7 COMPARISON OF COSTS AND BENEFITS

7.1 Introduction

This section provides a comparison of the costs and benefits of this action and discusses unquantified impacts. As discussed previously, the estimates of increased economic surplus reported in this section include the sum of changes in producer surplus (not including the value of product recovery), which account for changes in regulatory compliance costs; consumer surplus, which measures the cumulative distance between consumers' willingness-to-pay and market prices; and the value of product recovery from compliance activities. These estimates do not account for changes in economic welfare in the broader economy resulting from shifts in production and consumption outside of the oil and natural gas sectors that may be induced by this action. Furthermore, costs and benefits due to the emissions changes and interactions with pre-existing market distortions outside the directly regulated sector are omitted, as are any economic surplus changes that may be associated with the net change in transfers attributable to this action. Additional limitations of the analysis and sources of uncertainty are described throughout the RIA and summarized later in this section.

In addition to the proposed option, we also present analysis of the co-proposal as well as two regulatory alternatives, one more stringent than the proposed option and one less stringent. The co-proposal applies the subcategorization standards from Table 1-2 to conventional, rather than marginal, well sites. The more stringent option applies the same reconsideration of the standards (subcategorizing marginal sites) but also maintains the liquids unloading requirements from the 2024 Final Rule (best management practices) for marginal sites. For the less stringent option, we estimate the impacts of removing all requirements for marginal well sites.

The EPA calculated the PV and EAV of costs for the years 2027 through 2050, using the discount rates of 3 and 7 percent beginning-of-period discount rates, discounted to 2025 for the proposed reconsideration. All estimates are in 2024 dollars. The EPA used a simple partial equilibrium model of oil and gas production and consumption in the United States to estimate costs and emissions changes. The baseline for this analysis is the March 2024 Final Rule and the December 2025 Final Rule requirements for NSPS OOOOb and EG OOOOc. A comparison of costs and benefits is presented below in Section 7.3.

7.2 Qualitative Discussion of Unquantified Provisions

As detailed in Table 1-1, there are provisions of the proposed action whose impacts we are unable to quantify. These unquantified provisions are: (1) the Super Emitter Program rescission, (2) certain exemptions from monitoring and performance testing requirements for temporary control devices, (3) targeted additional allowances for temporary flaring episodes, (4) certain exemptions and changes to requirements for covers and closed vent systems, and (5) an exemption for high-pressure process controllers at compressor stations from the zero emissions standards.

The rescission of the Super Emitter Program, exemptions from certain testing requirements for temporary control devices, targeted amendments that allow for additional flaring, and exemption of high-pressure process controllers will likely result in additional cost savings that accrue to industry and an increase in domestic oil and gas production. These provisions will also likely result in increased emissions of methane, VOC, and HAP from oil and gas well sites and accompanying foregone health and welfare benefits resulting from exposure to such air emissions. The changes to requirements for covers and closed vent systems are primarily a definitional change and we lack information on what the potential impacts of this might be.

7.3 Results

The following two tables show the total emissions changes and the PV and EAV of quantified changes in economic surplus over the 2027 to 2050 period. Table 7-1 summarizes the emissions changes associated with the proposed standards. Table 7-2 presents the PV and EAV, estimated using discount rates of 3 and 7 percent, of the changes in surplus relative to the March 2024 Final Rule and the December 2025 Final Rule baseline. These values are discounted to 2025 and presented in 2024 dollars.

Table 7-1 Total Projected Emissions Increases under the Proposed Reconsideration across Regulatory Options from 2027-2050

Regulatory Option	Emissions Changes		
	Methane (millions short tons)	VOC (millions short tons)	HAP (millions short tons)
Less Stringent	140	41	5.1
Proposed Reconsideration	60	17	2.3
More Stringent	59	17	2.2
Co-Proposal	88	25	3.3

Notes: Values rounded to two significant figures. 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.

Table 7-2 Quantified Economic Surplus Changes and Non-Monetized Health and Environmental Outcomes across Regulatory Options for the Proposed Reconsideration Standards from 2027–2050 (million 2024\$, discounted to 2025)^{a,b}

	3 Percent Discount Rate		7 Percent Discount Rate	
	PV	EAV	PV	EAV
Change in Total Economic Surplus				
<i>Less Stringent</i>	\$52,000	\$3,000	\$36,000	\$3,100
<i>Proposed Reconsideration</i>	\$45,000	\$2,700	\$32,000	\$2,800
<i>More Stringent</i>	\$43,000	\$2,500	\$30,000	\$2,600
<i>Co-Proposal</i>	\$39,000	\$2,300	\$28,000	\$2,400

Non-Monetized Benefits

Changes in the incidence of adverse health effects related to changes in ozone exposure resulting from increased emissions of VOC.

Impacts on vegetation, ecosystems, and animal welfare related to changes in ozone exposure resulting from increased emissions of VOC.

Impacts from increased emissions of methane.

Changes in the incidence of adverse health effects related to changes in exposure to HAP resulting from increased HAP emissions.

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

^a Several provisions of the proposed reconsideration were not quantified such as the Super Emitter Program rescission, certain requirement exemptions, and changes to requirements for covers and closed vent systems. See Section 7.2 for a qualitative discussion of the provisions that are not quantified and thus remain unmonetized.

^b Health and welfare effects from increases in methane, VOC, and HAP emissions remain unmonetized and are therefore not directly reflected in the table. See Section 5 for a discussion on health and welfare effects.

7.4 Uncertainties and Limitations

Due to the extensive scope and specificity of the proposed rulemaking, our analysis requires significant data resources and many analytic assumptions to generate our best estimates of the projected impacts. Throughout the analysis, we leverage disparate sources of data and information, ranging from well-level production characteristics obtained through Enverus to the emission leak observations from industry surveys and academic studies that inform the emissions factors that this analysis shares with the BSER analysis. In addition, we make assumptions over a wide range of parameters such as annual operating costs and supply, demand, and trade elasticities, often extrapolating estimates across production sites and geographies due to data limitations. Finally, our model imposes additional assumptions on the behavior of market participants. This analysis reflects our best attempt to manage these uncertainties and limitations while providing as much insight as possible to the public on the potential impacts of the proposed action. We encourage feedback from stakeholders and the broader public on the appropriateness of the assumptions as well as suggestions on data sources and methods that can be used to overcome limitations.

Below, we summarize several of the key sources of uncertainty and limitations. We also attempt to offer some insight into how inaccuracies in our assumptions might bias our estimates.

Non-quantified regulatory impacts: We do not attempt to quantify regulatory impacts for all aspects of the proposed reconsideration in this RIA. As summarized in Table 1-1, we do not quantify impacts for the Super Emitter Program rescission, targeted additional allowances for temporary flaring episodes, certain exemptions and changes to requirements for covers and closed vent systems, and an exemption for high-pressure process controllers at compressor stations from the zero emissions standards; we anticipate these aspects of the proposal will likely result in additional cost savings that accrue to industry and an increase in domestic oil and gas production. These provisions will also likely result in increased emissions of methane, VOC, and HAP from oil and gas well sites and accompanying foregone health and welfare benefits resulting from exposure to such air emissions. We also do not quantify impacts for the changes to requirements for covers and closed vent systems, though those changes are definitional, and it is unclear what their potential impacts might be. Overall, we believe that this analysis sufficiently captures the most significant impacts of the proposed action. **Representation of**

state regulations and voluntary actions: To emphasize transparency, we have limited treatment of state regulations or voluntary actions in this analysis. The drawback of this approach is that, to the extent that such regulations or actions result in more compliance activities than our policy case assumes, our projected estimates exceed what they should be, all else equal. However, our experience, based on many years of analyzing this sector, has led us to believe that a credible accounting of state regulations is an enormous undertaking given the breadth of producing states, emissions sources, and regulatory approaches and exemptions. While we continue to work on accounting for state regulations, we do not do so for this analysis.⁶⁴ In addition, we have limited information that can be systematically and broadly applied to what emission-reducing activities operators undertake in the absence of regulatory requirements. The set of firms conducting oil and natural gas production operations is large and diverse, and so we would expect operator activities, including emissions mitigation measures such as leak detection and repair, to vary as well in the absence of regulation. Our limited ability to capture existing state regs and voluntary action in the baseline may cause us to overestimate the impacts of the proposed action, all else equal.

Characterization of equipment and emissions sources across sites: We do not possess well- or site-specific data on equipment and emissions sources for the universe of sites represented in our Enverus data. We attempt to deal with this limitation largely by leveraging external survey data to construct equipment distributions that can in turn be applied within a Monte Carlo simulation framework. This approach means that we are assuming generalizability of those surveys. While we believe the underlying survey data we incorporate to be the best available information, the size, timeliness, and geographic diversity of the industry means that there may be instances where our information is applied to sites for which the survey data is less representative.

Another potential issue related to our equipment characterization is that, once endowed in a simulation, we do not allow the equipment configuration at a site to change, nor do we assume

⁶⁴ While we do not explicitly attempt to account for state regulations when assigning control outcomes, the data we use for the analysis may embody outcomes that are influenced by state regulations (e.g., state-level production activity, estimated equipment distributions).

that equipment configuration is endogenous to regulatory policy.⁶⁵ This precludes, for instance, removal or consolidation of equipment at a site either as a natural consequence of production decline or in response to regulatory requirements as a cost mitigation measure. In either case, our treatment may cause us to overestimate the impacts of the proposed action, all else equal.

Decommissioning model structure and parameterization for base year sites:

Information on the operating costs of well sites is limited. Moreover, as discussed in Section 3.2.1, there is variation across sources of information on the structure of costs with respect to whether they vary with production levels or other attributes of the site. For this analysis, we assume that all operating costs are fixed at \$3,000 per year, but we have a low degree of confidence in these assumptions and would appreciate feedback on their appropriateness.

On the revenue side, the decommissioning model for base year sites requires assumptions about the random process governing the evolution of revenues over time. Since production is assumed to follow deterministic trajectories, the random process for revenues inherits the process for commodity prices. To simplify the analytic solution, the drift and variance parameters for the price process are based on the mean of estimates for historical oil and natural gas price paths. Future work will focus on deriving and implementing the analytic solution for the joint distribution of prices of both commodities, but this analysis employs a cruder representation.

Finally, another major assumption embedded in both the decommissioning and market equilibrium models is that product recovery from compliance activities is not internalized in the decision-making for production sites. We believe this is a reasonable assumption because emissions leak distributions for production sites tend to exhibit heavy tails, and so operators may be reluctant to pay for leak monitoring in the absence of regulation when the median outcomes will tend to yield minimal product recovery.

Extrapolation of supply elasticities: We apply our supply elasticity assumptions (for production from projected sites) uniformly across states. Those estimates tend to rely on production data from the states with the highest contributions to aggregate domestic supply, and so we may not be accurately representing producer responsiveness to regulatory costs in all

⁶⁵ For example, perhaps it would be possible in the baseline (2024 Final Rule) scenario for a site with two separators to remove one of the separators to change its regulatory requirements for fugitives from OGI+AVO to AVO only. This form of compliance is omitted because we don't have information on whether it's a viable strategy, and in what cases it may be applied.

jurisdictions. It is unclear whether the degree of supplier price responsiveness would be higher or lower in states with less production.

Representation of base year sites with lease-level data: For some states (most notably Michigan and Kansas), we do not have data that allows for estimation of well- or site-level production trajectories. For the states with lease-level data, we treat the leases as the unit of decision-making and assume an annual production decline rate of 5 percent. To the extent those leases would be more accurately represented as several smaller sites with independent decommissioning decisions, we may be slightly underestimating the number of marginal wells affected by the proposed action. All else equal, this may result in a slight underestimate of the impacts as the two states most affected by this data gap account for less than 10 percent of total wells in the United States.

Associated gas representation: Of the emissions sources characterized in this analysis, associated gas is the one for which we have the least amount of coherent data to draw upon. First, there is limited nationwide information on associated gas venting and flaring volumes, and the data that exists at the state-level would require significant information gathering and data processing work to convert it into a form that would match the conceptual framework of our model. For this analysis, we have attempted a limited assessment that focuses on associated gas emissions at sites that do not report natural gas sales, i.e., they produce oil and either vent, flare, or otherwise route gas for beneficial use or sequestration; all else equal, a broader assessment that included sites that routinely vent or flare but also report some gas sales would result in larger estimated deregulatory impacts for this action. For these sites, we assume a uniform quantity of associated gas per barrel and that a certain percentage of them would flare their associated gas in the absence of federal regulation, e.g., for health and safety reasons or to comply with state or local regulations. While our assumptions for those values reflect the information we have available, we have low levels of confidence in their accuracy due to a lack of data.

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