This document is scheduled to be published in the Federal Register on 2026-10-29 and available online at https://www.federalregister.gov/d/2026-22082, and on https://govinfo.gov

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2025-0163; FRL-12726-01-OAR]

RIN 2060-AW73

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

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is proposing amendments to the New Source Performance Standards and Emission Guidelines for the Crude Oil and Natural Gas Source Category to address additional concerns raised with prior regulatory amendments finalized in March 2024. Specifically, the EPA is proposing changes in response to certain petitions for reconsideration of the March 2024 amendments, changes based on policy decisions and supporting legal interpretations, and changes that correct and clarify the regulatory text of the new source performance standards and emission guidelines. First, the EPA proposes to rescind the Super Emitter Program. Second, the EPA proposes to subcategorize different types of well sites affected and designated facilities to address issues related to the requirements finalized in March 2024 for marginal well sites and conventional well sites. Third, the EPA proposes changes to address issues related to liquids unloading, process controllers, pumps, fugitive emissions, storage vessels, covers and closed vent systems, equipment leaks at gas plants, and associated gas. Fourth, the EPA proposes changes to certain requirements finalized in March 2024 related to control devices and to provide owners and operators the option to conduct optical gas imaging surveys according to Appendix K for gas

processing facilities. Lastly, the EPA proposes changes to correct inadvertent errors and to clarify regulatory language.

DATES: Comments must be received on or before **[INSERT DATE 48 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. The EPA will announce further details at https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations. Under the Paperwork Reduction Act, comments on the information collection provisions are best assured of consideration if the Office of Management and Budget receives a copy of your comments on or before **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

Public Hearing. The EPA will hold a virtual public hearing on **[INSERT DATE 15 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. Please refer to the **SUPPLEMENTARY INFORMATION** for information on registering for the public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA-HQ-OAR-2025-0163, by any of the following methods:

- Federal eRulemaking Portal: *https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- Email: *a-and-r-docket@epa.gov*. Include Docket ID No. EPA-HQ-OAR-2025-0163 in the subject line of the message.
- Mail: U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA-HQ-OAR-2025-0163, Mail Code 28221T, 1200 Pennsylvania Avenue, NW, Washington, DC 20460.
- Hand/Courier Delivery*:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue, NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Time (ET), Monday through Friday (except Federal holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov*, including any personal information provided. For detailed instructions on sending written comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this preamble.

FOR FURTHER INFORMATION CONTACT: For information about this proposed rule, contact Paz Aviles, Natural Resources Division, Office of Clean Air Programs, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, N.W., Washington, D.C. 20460; telephone number: (202) 564-9822; and email address: *aviles.paz@epa.gov*. Additional questions may be directed to the following email address: *O&GMethaneRule@epa.gov*.

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. The hearing will be held via virtual platform November 16, 2026. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations*.

The EPA will begin pre-registering speakers for the hearing no later than one business day after a request has been received. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations* or contact the public hearing team at (888) 372-8699 or by email at *NRDpublichearing@epa.gov*. The last day to pre-register to speak at the hearing will be November 10, 2026 . Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers at: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have four minutes to provide oral testimony. The EPA encourages commenters to submit a copy of their oral testimony as written comments electronically to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations*. While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact the public hearing team at (888) 372-8699 or by email at *NRDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the *Federal Register* announcing updates.

If you require special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by November 9, 2026. The EPA may not be able to arrange accommodations without advance notice.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA-HQ-OAR-2025-0163. All documents in the docket are listed at *https://www.regulations.gov*. Although listed, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The EPA does not place certain other material, such as copyrighted material, on the Internet; this material is publicly available only as portable

document format versions accessible only on EPA computers in the docket office reading room. The public cannot download certain databases and physical items from the docket but may request these items by contacting the docket office at (202) 566-1744. The docket office has 10 business days to respond to such requests. With the exception of such material, publicly available docket materials are available electronically at *https://www.regulations.gov* or on EPA computers in the docket office reading room at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave., NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. ET, Monday through Friday. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the EPA Docket Center is (202) 566-1742. Pursuant to the Administrative Procedure Act at 5 U.S.C. 553(b)(4), a plain language summary of this rule is available on the docket at *https://www.regulations.gov*.

Written Comments. Direct your comments to Docket ID No. EPA-HQ-OAR-2025-0163. The EPA's policy is that the public docket will contain all comments received without change and made available online at *https://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be CBI or other information for which a statute restricts disclosure. Do not submit electronically to *https://www.regulations.gov* any information that you consider to be CBI or other information for which a statute restricts disclosure. You should submit this type of information as described in the *Submitting CBI* section of this preamble.

The EPA may publish any comment received to its public docket. A written comment must accompany multimedia submissions (audio, video, *etc.*). The EPA considers the written comment to be the official comment, and it should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the Web, cloud, or other file sharing system). For additional submission methods, the full

EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets*.

The *https://www.regulations.gov* website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov*, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *https://www.epa.gov/dockets*.

The EPA solicits comment on numerous aspects of this proposed rule. The EPA has indexed each comment solicitation with an identifier (*e.g.*, "C-1, C-2, . . ") to provide a consistent framework for effective and efficient provision of comments. Accordingly, the EPA asks that commenters include the corresponding identifier when providing comments relevant to that comment solicitation. The EPA asks that commenters include the identifier in either a heading or in the text of each comment (*e.g.*, "In response to C-1, . . .") to make clear which comment solicitation you are addressing. The EPA emphasizes that the EPA is not limiting comment to these identified areas and encourage you to provide any other comments relevant to this proposal.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov*. Clearly mark the part or all the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* above. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services (*e.g.*, Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the Office of Clean Air Programs at the email address *ocapcbi@epa.gov* and, as described above, should include clear CBI markings and note the docket ID. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to receive instructions.

Preamble acronyms and abbreviations. Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. The Agency uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of

this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

AMEL	alternative means of emission limitation
API	American Petroleum Institute
ASTM	ASTM International
AVO	audible, visual, and olfactory
BCD	backup control devices
BMPs	best management practices
boe	barrels of oil equivalents
BSER	best system of emission reduction
°C	degrees Celsius
CAA	Clean Air Act
CBI	Confidential Business Information
CDX	Central Data Exchange
CEDRI	Compliance and Emissions Data Reporting
CFR	Code of Federal Regulations
CVS	closed vent systems
DOE	Department of Energy
EAV	equivalent annualized values
ECD	enclosed combustion device
EG	emission guidelines
EPA	Environmental Protection Agency
°F	degrees Fahrenheit
FR	*Federal Register*
g/hr	grams per hour
GHG	greenhouse gas
GOR	gas-to-oil ratio
H_2S	hydrogen sulfide
ICR	information collection request
IFR	interim final rule
kg/hr	kilograms per hour
low-E	low emission
LDAR	leak detection and repair
LPE	legally and practicably enforceable
Mcfd	thousand cubic feet per day
MOGA	Michigan Oil and Gas Association
MPT	Manufacturers' Performance Test
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NDE	no detectable emissions
NESHAP	National Emission Standards for Hazardous Air Pollutants
NIE	no identifiable emissions
NHV	net heating value
NSPS	new source performance standards
NTTAA	National Technology Transfer and Advancement Act
OCAP	Office of Clean Air Programs
OGI	optical gas imaging
OIRA	Office of Information and Regulatory Affairs
OMB	Office of Management and Budget
psig	Pounds per square inch gauge

ppmv	parts per million by volume
PRA	Paperwork Reduction Act
PTE	potential to emit
PV	present value
RFA	Regulatory Flexibility Act
RIA	regulatory impact analysis
scfh	standard cubic feet per hour
SO_2	sulfur dioxide
TCD	temporary control device
tpy	tons per year
TIP	Tribal Implementation Plan
TSD	technical support document
UMRA	Unfunded Mandates Reform Act
U.S.	United States
VOC	volatile organic compound(s)
VRU	vapor recovery unit

Table of Contents

I. Executive Summary
II. General Information
A. Applicability of This Regulatory Action
B. Availability of This Document and Other Related Information
C. Purpose of This Regulatory Action
D. Statutory Background and Authority
E. Regulatory History and Background of NSPS and EG for the Crude Oil and Natural Gas Source Category
III. Summary and Rationale of Proposed Amendments to NSPS OOOOb and EG OOOOc
A. Super Emitter Program
B. Liquids Unloading
C. Process Controllers
D. Pumps
E. Fugitive Emissions
F. Storage Vessels
G. Covers and Closed Vent Systems
H. Control Devices
I. Equipment Leaks at Gas Plants
J. Associated Gas from Wells Producing Primarily Oil
K. Well Site Subcategorization
IV. Technical Corrections and Clarifications
A. NSPS Subparts OOOO and OOOOa Technical Corrections and Clarifications
B. NSPS Subpart OOOOb Technical Corrections and Clarifications
C. EG Subpart OOOOc Technical Corrections and Clarifications
V. Appendix K
A. Summary of Provisions Promulgated in March 2024 Final Rule
B. Petitioners' Concerns and Supporting Information, Summary of Proposed Changes, and Basis for Proposed Changes
VI. Summary of Cost, Environmental, and Economic Impacts
VII. Request for Comments
VIII. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review
B. Executive Order 14192: Unleashing Prosperity Through Deregulation

C. Paperwork Reduction Act (PRA)
D. Regulatory Flexibility Act (RFA)
E. Unfunded Mandates Reform Act (UMRA)
F. Executive Order 13132: Federalism
G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
I. Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use
J. National Technology Transfer and Advancement Act (NTTAA) and 1 Code of Federal Regulations (CFR) part 51

I. Executive Summary

On March 8, 2024, the EPA published a final rule amending and expanding requirements for the Crude Oil and Natural Gas source category under Clean Air Act (CAA) sections 111(b) and (d) ("March 2024 Final Rule").[1] The EPA finalized new source performance standards (NSPS) for greenhouse gas (GHG) and volatile organic compound (VOC) emissions from new, modified, and reconstructed sources in this source category, codified in 40 Code of Federal Regulations (CFR) part 60, subpart OOOOb (NSPS OOOOb). The EPA also finalized emission guidelines (EG) for GHG emissions from existing sources in this source category, codified in 40 CFR part 60, subpart OOOOc (EG OOOOc). The NSPS OOOOb applies to thousands of new sources, whose construction, reconstruction, or modification began after December 6, 2022, and the EG OOOOc covers hundreds of thousands of existing sources in the Crude Oil and Natural Gas source category. Crude oil production applicability includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation. Natural gas production applicability includes production, processing, transmission, and storage, which includes the well and extends to, but does not include, the local distribution company custody transfer station.

[1] 89 FR 16820 (March 8, 2024).

The March 2024 Final Rule broke new ground in multiple respects. In EG OOOOc, the EPA required States to regulate GHG emissions from hundreds of thousands of existing sources in the Crude Oil and Natural Gas source category for the first time. This novel and massive task is presenting additional and, at times, unforeseen coordination and compliance difficulties. For several aspects of NSPS OOOOb and EG OOOOc, the EPA promulgated ambitious "zero-emission requirements" predicated on very different best system of emissions reduction (BSER) determinations. With respect to associated gas produced during oil extraction, for example, the EPA predicated its zero-emission standard for new sources on a BSER of routing gas to sales lines based on the assumption that sources would be located in an area where such infrastructure—generally owned and operated by third parties—is, or would be, established at sufficient scale. Recognizing that not all existing sources fit within that assumption, the Agency built subcategories into the BSER analysis and resulting presumptive standards that allow continued flaring under certain circumstances. For new sources, the Agency concluded that it was appropriate to require routing to a sales line based, among other things, on a cost-effectiveness analysis that assumed new sources would be located within 50 miles of existing infrastructure. This approach broadened the BSER analysis from source-centered compliance to one that very heavily relied on industry-wide participants unregulated by NSPS OOOOb and EG OOOOc, which raised novel legal and policy questions that the Agency did not fully grapple with at the time of promulgation. The resulting new source standard in the March 2024 Final Rule, as discussed herein, risks limiting the development of new oil and gas extraction areas where potential sources must hold back until or unless necessary infrastructure develops, thereby coming into tension with the economics of the industry, national security and energy priorities, and CAA section 111's instruction to develop new source standards that can be achieved across the Nation.

After publication of the March 2024 Final Rule, the EPA received multiple petitions for reconsideration.[2] On May 6, 2024, the EPA notified certain petitioners and the public that the Agency granted reconsideration on two discrete aspects of the March 2024 Final Rule: the temporary flaring provisions for associated gas in certain situations; and the vent gas net heating value (NHV) continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices.[3, 4]

On January 15, 2025, the EPA proposed amendments to the NSPS and EG for Existing Sources for the Crude Oil and Natural Gas Source Category in response to these petitions for reconsideration ("January 2025 Reconsideration Proposal").[5] Specifically, the EPA proposed discrete technical changes to two different aspects of the March 2024 Final Rule (*i.e.*, technical changes to the temporary flaring provisions for associated gas in certain situations; technical changes to the vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices).

On April 9, 2026, the EPA finalized amendments to the March 2024 Final Rule resulting from our reconsideration of these two discrete issues ("April 2026 Reconsideration Final Rule").[6] The EPA is not reopening NHV issues from the April 2026 Reconsideration Final Rule in this new rule. This package is proposing changes to associated gas and can be found in section III.J. of this preamble. The proposed changes to associated gas will address broader issues than those raised in the April 2026 Reconsideration Final Rule, including proposing to remove the provisions related to temporary flaring.

---

[2] *See* Docket No. EPA-HQ-OAR-2025-0163 for petitions for reconsideration received.
[3] *See* Docket No. EPA-HQ-OAR-2025-0163 for May 6, 2024, letter granting reconsideration.
[4] In the May 6, 2024, letter to petitioners, the EPA also took the opportunity to clarify the applicable timeframe for performance testing with respect to NHV sampling.
[5] 90 FR 3734 (January 15, 2025).
[6] 91 FR 18056 (April 9, 2026).

On January 20, 2025, the President issued Executive Orders 14154 (Unleashing American Energy) and 14156 (Declaring a National Energy Emergency).[7, 8] Then, on January 31, 2025, the President issued Executive Order 14192 (Unleashing Prosperity through Deregulation).[9] On March 12, 2025, the EPA announced plans for deregulatory actions to, among other things, unleash American energy.[10] On that same day, the Agency announced plans to reconsider the regulations in the March 2024 Final Rule "to ensure they do not prevent America from unleashing energy dominance."[11]

On July 31, 2025, the EPA promulgated an interim final rule ("July 2025 IFR") 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 (CVS) to address legitimate concerns, raised by stakeholders, that certain regulatory provisions were not currently workable or contained problematic regulatory language that frustrates compliance.[12] 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. The EPA solicited public comment on the extensions included in the July 2025 IFR. The EPA considered the comments received, and then, in December 2025, the EPA promulgated a final rule which responded to the comments and reaffirmed the conclusions and the regulatory amendments made in the IFR ("December 2025 Final Rule").[13] In response to comments received on the July 2025 IFR, the December 2025 Final Rule provided an additional 180-day extension (from the final rule's effective date) (until June 1, 2026) to the compliance dates related to NHV

---

[7] 90 FR 8353 (January 29, 2025).
[8] 90 FR 8433 (January 29, 2025).
[9] 90 FR 9065 (February 6, 2025).
[10] EPA Press Release: EPA Launches Biggest Deregulatory Action in U.S. History. https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history. March 12, 2025.
[11] EPA Press Release: Trump EPA Announces OOOO b/c Reconsideration of Biden-Harris Rules Strangling American Energy Producers. https://www.epa.gov/newsreleases/trump-epa-announces-oooo-bc-reconsideration-biden-harris-rules-strangling-american. March 12, 2025.
[12] 90 FR 35966 (July 31, 2025).
[13] 90 FR 55671 (December 3, 2025).

monitoring of flares and enclosed combustion devices (ECDs) found in 40 CFR 60.5417b(d)(8)(i) through (iv) and (vi), as well as 360 days from the effective date of the December 2025 Final Rule (November 30, 2026) for owners and operators to submit initial annual reports pursuant to 40 CFR 60.5420(b).[14]

This proposal reflects the EPA's reconsideration of additional aspects of the March 2024 Final Rule, including some of the Agency's prior BSER determinations and the legal and policy positions taken in finalizing those determinations. Upon further review, and in light of information considered since promulgation, the EPA no longer believes that some of the "zero-emission" requirements in NSPS OOOOb and EG OOOOc are predicated on acceptable assessments of emissions reductions, cost effectiveness, and achievability. In some cases, the March 2024 Final Rule moved from requirements that control 95 percent of emissions to standards stated as "zero-emission" requirements. However, achievability limitations and compliance difficulties, including those the EPA anticipated at the time by building in exemptions and those the Agency did not foresee, suggest that the requirements' emission reductions potential are more modest than previously anticipated. At the same time, the Agency very likely underestimated costs because the actual costs of compliance are likely higher than the EPA anticipated in the March 2024 Final Rule. The resulting reconsideration — taking into account more modest emissions reductions and more significant costs—suggests that significant aspects of some BSER determinations and resulting standards in the March 2024 Final Rule are inappropriate. EPA solicits comment on further considerations relative to the March 2024 Final Rule, such as those petitioners have flagged.

In this action, the EPA proposes the following:

[14] *See* 90 FR 35970-35972 (July 31, 2025), and 90 FR 55675-55676 (December 3, 2025) for discussion of the rationale for NHV monitoring extension.

- Rescinding the Super Emitter Program in NSPS OOOO, OOOOa, OOOOb, and EG OOOOc based on a change in policy direction, concerns with the authority of the program, and a reassessment of the Program's expected effectiveness in light of new information.
- Revising several aspects of NSPS OOOOb and EG OOOOc based on petitions received on the March 2024 Final Rule. Specifically, the EPA proposes changes to the March 2024 Final Rule requirements to address certain petitioner concerns for liquids unloading, process controllers, pumps, fugitive emissions, storage vessels, covers and CVSs, and equipment leaks at gas plants.
- Revising the March 2024 Final Rule requirements related to control devices, such as requirements for continuous burning pilot flames, flame monitoring data deviations, control device alerts, visible emissions test conditions for fugitive emissions, control devices used on a temporary or backup basis, temporary process controllers, and control device categories.
- Proposing changes related to requirements for controlling emissions from associated gas from wells producing primarily oil. The EPA is proposing that routing to a sales-line is not an appropriate BSER for these emissions. The Agency is proposing that routing associated gas to a control device or a flare that achieves 95% reductions in emissions or greater should be BSER instead.
- Proposing to add a new subcategory for certain well sites affected and designated facilities based on a variety of operational conditions. This aspect of the proposal also includes revisions to requirements that apply at certain well sites that address concerns related to the appropriateness of the categorization and the burden associated with complying with the

March 2024 Final Rule requirements. Specifically, in this action, the EPA is co-proposing two alternative approaches to subcategorizing well sites:

    - An option based on marginal and non-marginal well sites that would include reduced requirements for marginal wells. The EPA also solicits comment on an alternative approach to a marginal well site subcategory that would further subcategorize marginal wells based on production levels.
    - An option based on conventional and non-conventional wells that would include reduced requirements for conventional wells.

- Allowing for owners and operators to conduct optical gas imaging (OGI) surveys according to Appendix K for NSPS OOOO, OOOOa, and KKK at gas processing facilities.
- Making technical corrections and clarifications to NSPS OOOO, OOOOa, OOOOb, and EG OOOOc.

The EPA solicits comments on its proposed regulatory changes. Within this preamble, the EPA is also soliciting broader comment on further issues relevant to the March 2024 Final Rule and resulting NSPS OOOOb and EG OOOOc, including both the additional issues raised by reconsideration petitioners for which the EPA is not proposing regulatory changes at this time and any additional issues commenters believe are relevant to the lawfulness, reasonableness, or implementability of the 2024 Final Rule. (Question I.1)

The EPA is also clarifying in this preamble an inconsistency identified in the amendatory instructions published as part of the April 2026 Reconsideration Final Rule. The amendatory language appeared to indicate a revision to 40 CFR 60.5417b(i)(6),[15] which had been revised as part of an earlier action (an IFR promulgated on July 31,

[15] 91 FR 18094 (April 9, 2026).

2025). The regulatory text in the CFR correctly reflects that earlier amendment. The inconsistency occurred only in the amendatory instructions and did not affect the regulatory text. In this notice, the EPA is not proposing any revisions to paragraph 40 CFR 60.5417b(i)(6)(v). The EPA is instead clarifying the source of the discrepancy to ensure transparency in the rulemaking record and to confirm that the existing regulatory text remains accurate and unchanged.

The EPA estimated present values (PV) and equivalent annualized values (EAV) of the estimated increase in economic surplus of this proposal and co-proposal in 2024 dollars over the 2027 to 2050 period, discounted to 2025. Estimated increases in economic surplus include reductions in compliance cost expenditures from industry, as well as increased value to consumers from lower commodity prices and revenues to industry from increased production. Surplus changes also account for the forgone value of natural gas captured as a result of less stringent compliance obligations. Changes beyond compliance cost savings are represented by the Savings from Energy Market Impacts values. Table 1 presents the estimated additional economic surplus of this proposed action in 2024 dollars for the baseline which includes the March 2024 Final Rule (*i.e.*, the primary baseline analyzed in the regulatory impact analysis (RIA)).

Table 1. Present Value and Equivalent Annualized Value of Increased Economic Surplus Estimates of the Proposed Action, Discounted to 2025 (Millions of 2024 Dollars), 2027-2050[a]

		3 Percent Discount Rate		7 Percent Discount Rate	
		PV	EAV	PV	EAV
Proposed Reconsideration	Compliance Cost Savings[b]	$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
Co-Proposal	Compliance Cost Savings[b]	$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

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] The Compliance Cost Savings rows include the change in value of product recovery.

See section VI of this preamble (Summary of Cost, Environmental, and Economic Impacts) for additional information.

II. General Information

A. Applicability of This Regulatory Action

The source category that is the subject of this proposal is the Crude Oil and Natural Gas Source Category regulated under CAA section 111, NSPS and EG. The 2022 North American Industry Classification System (NAICS) code for the source category is summarized in table 2. The NAICS codes serve as a guide for readers outlining the entities that this proposed action is likely to affect, if finalized. The NSPS codified in 40 CFR part 60, subpart OOOOb, are directly applicable to affected facilities that begin construction, reconstruction, or modification after December 6, 2022. As shown in table 2, Federal, State, and local government entities would not be affected by the NSPS action.

Table 2. Industrial Source Categories Affected by NSPS Action

Category	NAICS Code	Examples of Regulated Entities
Industry	211120	Crude Petroleum Extraction
	211130	Natural Gas Extraction
	221210	Natural Gas Distribution
	486110	Pipeline Distribution of Crude Oil
	486210	Pipeline Transportation of Natural Gas
Federal Government	. . . .	Not affected
State and local Government	. . . .	Not affected
Tribal Government	921150	American Indian and Alaska Native Tribal Governments

This table is not intended to be exhaustive but rather provides a guide for readers regarding entities likely to be affected by the NSPS action with respect to new sources. Other types of entities not listed in the table could also be affected by the NSPS action. To determine whether your entity is affected by any of the NSPS action, you should carefully examine the applicability criteria found in the final NSPS rule. If you have questions regarding the applicability of the NSPS rule to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section, your State air pollution control agency with delegated authority for NSPS, or your EPA Regional Office.

The issuance of the CAA section 111(d) EG in March 2024 did not directly impose binding requirements on existing sources, but instead established requirements applicable to states in developing their plans. While the presumptive standard determined by the EPA is the starting point for a state's standards of performance in its state plan, a state may choose to take into account remaining useful life and other factors in applying a standard of performance to a particular source, consistent with the CAA, the EPA's implementing regulations, and the final EG. The EG codified in 40 CFR part 60, subpart OOOOc, applies to States in the development, submittal, and implementation of State plans to establish performance standards to reduce emissions of GHGs from designated facilities that are existing sources on or before December 6, 2022. Under the Tribal

Authority Rule, eligible Tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a State.[16] Tribes may, but are not required to, seek approval for treatment in a manner similar to a State to develop Tribal implementation plans (TIPs) implementing the EG codified in 40 CFR part 60, subpart OOOOc. The Tribal Authority Rule authorizes Tribes to develop and implement their own air quality programs, or portions thereof, under the CAA. However, it does not require Tribes to develop a CAA program. Tribes may implement programs that are most relevant to their air quality needs. If a Tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country.[17] A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves a TIP applicable to those facilities.

B. Availability of This Document and Other Related Information

In addition to being available in the docket, at Docket ID No. EPA-HQ-OAR-2025-0163 located at *https://www.regulations.gov,* an electronic copy of this action is available on the Internet at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations*. A brief summary of this proposed rule may be found at *www.regulations.gov*, Docket ID No. EPA-HQ-OAR-2025-0163. Following publication in the *Federal Register*, the EPA will post the *Federal Register* version of the proposal and key technical documents at this same website.

A memorandum showing the edits that would be necessary to incorporate the changes to 40 CFR part, 60 subparts KKK, OOOO, OOOOa, OOOOb and OOOOc proposed in this action is available in the docket (Docket ID No. EPA-HQ-OAR-2025-

[16] *See* 40 CFR part 49, subpart A.

[17] *See* the EPA's website, https://www.epa.gov/tribal/tribes-approved-treatment-state-tas, for information on those Tribes that have treatment as a State for specific environmental regulatory programs, administrative functions, and grant programs.

0163). Following signature by the Administrator, the EPA also will post a copy of this document to *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations*.

C. Purpose of this Regulatory Action

On March 8, 2024, the EPA finalized NSPS for GHG and VOC emissions from new, modified, and reconstructed sources in this source category, codified in 40 CFR 60, subpart OOOOb (NSPS OOOOb) as well as EG for GHG emissions from existing sources in this source category, codified in 401 CFR 60, subpart OOOOc (EG OOOOc).

Prior to the March 2024 Final Rule, NSPS Subparts for this source category underwent multiple rounds of major policy revisions, technical amendments, and congressional actions. For example, NSPS OOOO (2012) applied only to VOC and sulfur dioxide emissions from new, modified, and reconstructed sources mainly in the upstream oil and gas sector. Although methane wasn't directly regulated, many upstream controls that targeted VOCs—like green completions, tank vapor control, and low-bleed pneumatics—also reduced methane as a co-benefit ("co-control"). In 2016, NSPS OOOOa added methane as a regulated pollutant and expanded coverage to include the midstream, adding requirements for transmission and storage, and additional source types (e.g., leak detection and repair (LDAR) at well sites and compressor stations, pneumatic pumps, compressors, hydraulically fractured oil wells). In 2020, EPA issued a rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review," September 14, 2020 (2020 Policy Rule), which removed the transmission and storage segment from the NSPS OOOO and OOOOa, rescinding VOC and methane emissions standards for that segment, and rescinded methane emissions standards for the production and processing segments. However, a joint congressional resolution disapproved the 2020 Policy Rule.

More recently, in 2024, NSPS OOOOb clarified the scope and coverage for addressing liquids unloading and certain intermittent emissions and added more stringent standards and methods, such as zero-emitting pneumatics, limits on routine flaring of associated gas at new oil wells, stronger LDAR with advanced detection options, tighter compressor requirements, and a super-emitter response program.

After publication of the March 2024 Final Rule, the EPA received, and continued to receive, multiple petitions for reconsideration.[18] Additionally, following Executive Orders 14154 (Unleashing American Energy), 14156 (Declaring a National Energy Emergency), and Executive Order 14192 (Unleashing Prosperity through Deregulation), the EPA announced plans for deregulatory actions intended, among other things, to unleash American energy and advance national energy policy goals.[19] Against the backdrop of these Executive Orders, the EPA Administrator publicly announced reconsideration of the regulations in 40 CFR part 60, subparts OOOOb and OOOOc, in the March 2024 Final Rule. [20]As explained in further detail below, as a result of the EPA's thorough examination of the March 2024 Final Rule, the Agency has identified several aspects of the March 2024 Final Rule that merit proposed substantive regulatory changes.

In this proposed rule, the EPA proposes targeted amendments to the NSPS and EG for Existing Sources for the Crude Oil and Natural Gas Source Category, partially in response to issues raised in petitions to reconsider the March 2024 Final Rule. While the purpose of this rulemaking is not intended to respond to all petitioner requests, the EPA addresses several petitioner requests in this rulemaking. If a petitioner request is not

---

[18] *See* Docket No. EPA-HQ-OAR-2025-0163 for petitions for reconsideration received.
[19] EPA Press Release: EPA Launches Biggest Deregulatory Action in U.S. History. https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history. March 12, 2025.
[20] EPA Press Release: Trump EPA Announces OOOO b/c Reconsideration of Biden-Harris Rules Strangling American Energy Producers. https://www.epa.gov/newsreleases/trump-epa-announces-oooo-bc-reconsideration-biden-harris-rules-strangling-american. March 12, 2025.

addressed in this rulemaking, that does not mean that EPA will not address the petitioner request in the future.

D. Statutory Background and Authority

CAA section 111 authorizes the EPA to list and regulate categories of stationary sources that the Administrator, "in his judgment," finds that the source category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[21] The listing of a source category triggers an obligation to promulgate "standards of performance" for new sources and, under limited circumstances, to prescribe regulations under which States submit plans that establish standards of performance for existing sources.[22] This provision, along with agencies' authority to reconsider prior regulations, provides the EPA's statutory authority for this proposed action.[23]

CAA section 111(b)(1)(A) authorizes the Administrator to publish, and from time-to-time revise, a list of categories of stationary sources that the Administrator, "in his judgment," finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Once the EPA lists a source category under CAA section 111(b)(1)(A), the EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for "new sources" in the source category. These standards are referred to as NSPS. The NSPS are national requirements that apply directly to new sources within the relevant source category.

Congress intended the NSPS to work together with the geography-based national ambient air quality standards (NAAQS) program in CAA sections 107-110. Similar to national emission standards for hazardous air pollutants (NESHAPs) that limit emissions

---

[21] 42 U.S.C. 7411(b)(1)(A).
[22] 42 U.S.C. 7411(b), (d).
[23] *See FDA v. Wages & White Lion Invs., LLC*, 604 U.S. 542, 568 (2025); *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 517-18 (2009); *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 41-42 (1983); *see also Clean Air Council v. Pruitt*, 862 F.3d 1, 8 (D.C. Cir. 2017) ("Agencies obviously have broad discretion to reconsider a regulation at any time.")

of hazardous air pollutants (HAPs) listed and regulated under CAA section 112, NSPS under CAA section 111 apply to a new source regardless of whether the area in which the new source is located is subject to NAAQS-related limitations and requirements. Accordingly, CAA section 111(a)(2) defines a "new source" as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section, which will be applicable to such source." CAA section 111(a)(4) further defines "modification" as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." While this provision treats modified sources as new sources, the EPA's regulations also treat a source that undergoes "reconstruction," by substantially replacing its components, as a new source.[24]

CAA section 111(a)(1) defines "standard of performance" as "a standard for emissions of air pollutants" that must be promulgated or revised in a specified manner. When the EPA establishes or revises a performance standard, CAA section 111(a)(1) provides that such standard must "reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." Thus, the term "standard of performance" as used in CAA section 111 makes clear that the foundation for the regulatory requirements for the source category is the EPA's determination of the BSER that is "adequately demonstrated" for emissions of the relevant air pollutants.[25] The EPA has discretion in determining the BSER,

[24] 40 CFR 60.15.
[25] *West Virginia v. EPA*, 597 U.S. 697, 709 (2022).

and has historically followed a "technology-based approach" that focuses on "measures that improve the pollution performance of individual sources," such as "add-on controls."[26]

To determine the BSER, the EPA first identifies the "system[s] of emission reduction" that are "adequately demonstrated" and then determines the "best" of those adequately demonstrated systems, "taking into account" factors including "cost," "nonair quality health and environmental impact," and "energy requirements." After determining the BSER, the EPA derives from that system an "achievable" "degree of emission limitation." A standard of performance is "achievable" if a technology can reasonably be projected to be available to an individual source at the time it is constructed so as to allow it to meet the standard.[27] The EPA must then, under CAA section 111(b)(1)(B), promulgate "standard[s] for emissions"—the NSPS—that reflect that level of stringency. The EPA may determine that different sets of sources have different characteristics relevant for determining the BSER for emissions of the relevant air pollutants and may subcategorize sources accordingly.[28]

To qualify as the BSER, the system of emission reduction must be "adequately demonstrated" as "the Administrator determines."[29] The plain text of CAA section 111(a)(1), and in particular the terms "adequately" and "the Administrator determines," confers upon the EPA the discretion to identify the appropriate system, including making scientific and technological determinations and considering a broad range of policy considerations.[30] The D.C. Circuit has stated that the EPA may weigh the various factors identified in the statute and caselaw to determine the "best" system and has emphasized that the EPA has significant discretion in weighing the factors (cost, health and

---

[26] *See id*. at 727 (quoting an EPA rule).
[27] Sierra Club v. Costle, 657 F.2d 298, 364 n.276 (D.C. Cir. 1981).
[28] 42 U.S.C. 7411(b)(2).
[29] 42 U.S.C. 7411(a)(1).
[30] *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 786 (D.C. Cir. 1976); *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 434 (D.C. Cir. 1973).

environmental impact, and energy requirements).[31] The EPA has broad discretion in determining which adequately demonstrated system of emission reduction is the "best." The D.C. Circuit has explained that "section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS"[32] and emphasized that "[t]he text gives the EPA broad discretion to weigh different factors in setting the standard," including the amount of emission reductions, the cost of the controls, and the nonair quality environmental impacts and energy requirements.[33]

CAA section 111(a)(1) requires the EPA to account for "the cost of achieving [the emission] reduction" in determining the adequately demonstrated BSER. Although the CAA does not describe how the EPA should account for costs to affected sources, the D.C. Circuit has formulated the cost standard in various ways, including by stating on the upper bound that the EPA may not adopt a standard that the cost of which would be "excessive" or "unreasonable."[34] The EPA has discretion in considering cost under CAA section 111(a), both in determining the appropriate level of costs and in balancing costs with other BSER factors.[35] The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance.[36] Regarding energy impacts, based on the D.C. Circuit's interpretations of CAA section 111, this factor may also include the impact, if any, of the air pollution controls on the energy supply for a

---

[31] *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them.").
[32] *Sierra Club v. Costle*, 657 F.2d 298, 319 (D.C. Cir. 1981).
[33] *Id.* at 321; *see also New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992).
[34] *Sierra Club*, 657 F.2d at 343; *id.* at 383 (affirming a standard that was achievable and not "unreasonably costly"); *see* 79 FR 1430, 1464 (January 8, 2014); *Lignite Energy Council*, 198 F.3d at 933 (costs may not be "exorbitant"); *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975) (noting with approval the EPA's conclusion that "where the costs of meeting standards greater than the industry could bear and survive, such standards could not be implemented by the industry regardless of technological feasibility").
[35] *Sierra Club*, 657 F.2d at 343.
[36] *See Essex Chem. Corp.*, 486 F.2d at 440; *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 387-88 (D.C. Cir. 1973); *Sierra Club*, 657 F.2d at 313.

particular area or nationwide.[37] Furthermore, the EPA has considered under this statutory factor whether possible controls would create risks to the reliability of the national electricity system.[38]

The EPA has generally used CAA section 111 to establish NSPS for emissions of specified air pollutants from new sources within a category. In the rare instances in which the new stationary source standards concern air pollutants that are not regulated under the NAAQS program pursuant to CAA sections 108-110, or the NESHAP program pursuant to CAA section 112, the statute provides a separate authority for addressing emissions of such air pollutants from existing sources in the source category.[39] CAA section 111(a)(6) defines an "existing source" as "any stationary source other than a new source."

In contrast to the national regime for new sources under CAA section 111(b), CAA section 111(d) establishes a framework of "cooperative federalism for the regulation of existing sources."[40] CAA section 111(d)(1) provides that when air pollutants covered by an NSPS for a source category are not already encompassed within the NAAQS program or NESHAP program, the EPA "shall prescribe regulations which shall establish a procedure similar to that provided by" CAA section 110 "under which each State shall submit to the Administrator" a plan for addressing emissions of such air pollutants by existing sources within such source category.[41] Reference to CAA section 110 incorporates the statute's provision for State submission and EPA review of state implementation plans (SIPs) that provide for the implementation, maintenance, and

---

[37] *See Sierra Club*, 657 F.2d at 327-28 (quoting 44 FR 33580, 33583-84 (June 11, 1979)); 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club*, 657 F.2d at 351).
[38] *See* 89 FR 39886 (May 9, 2024).
[39] 42 U.S.C. 7411(d)(1)(A)(i)-(ii); *see West Virginia*, 597 U.S. at 710 ("Section 111(d) thus 'operates as a gap-filler,' empowering EPA to regulate harmful emissions not already controlled under the Agency's other authorities.…Reflecting the ancillary nature of Section 111(d), EPA has used it only a handful of times since the enactment of the statute in 1970.").
[40] *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 931 (D.C. Cir. 2021), *rev'd in part sub nom. West Virginia*, 597 U.S. 697.
[41] 42 U.S.C. 7411(d)(1). CAA section 111(a)(6) defines an "existing source" as "any stationary source other than a new source." 42 U.S.C. 7411(a)(6).

enforcement of the NAAQS for the areas within such State.[42] In a comparable manner, State plans required by the regulations authorized in CAA section 111(d) must "establis[h] standards of performance for any existing stationary source" for the air pollutant at issue and "provid[e] for the implementation and enforcement of such standards of performance."

In the relatively few instances in which the EPA applies this provision, the Agency generally promulgates "emission guidelines" that identify the BSER and the degree of emission limitation achievable through the application of the BSER. (represented in EG OOOOc via presumptive standards in a model rule). The EPA's regulations then require States to establish standards of performance for emissions of the air pollutant at issue by covered sources that reflect that level of stringency. States need not compel regulated sources to adopt the particular components of the BSER itself (or the model rule or presumptive standards); rather, States have discretion in designing the policies and rules used to achieve the degree of emission limitation required by the EPA's emission guidelines. The statute requires the EPA's regulations to permit a State, "in applying a standard of performance to any particular source," to "take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[43]

Once the EPA approves a State's plan, the provisions in the plan become federally enforceable in the same manner as the provisions of an approved SIP under the CAA.[44] If a State elects not to submit a plan or submits a plan that the EPA does not find "satisfactory," the Agency is authorized to promulgate a plan that establishes Federal standards of performance for the state's existing sources.[45] In establishing Federal

[42] 42 U.S.C. 7410.
[43] 42 U.S.C. 7411(d)(1).
[44] 42 U.S.C. 7411(d)(2)(B).
[45] 42 U.S.C. 7411(d)(2)(A).

standards of performance for existing sources under these circumstances, the EPA must "take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."[46]

E. Regulatory History and Background of NSPS and EG for the Crude Oil and Natural Gas Source Category

The EPA has regulated VOC emissions from the Crude Oil and Natural Gas source category since 1985 when the EPA promulgated NSPS for the Crude Oil and Natural Gas source category.[47] That rule addressed VOC emissions from equipment leaks at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985, the EPA promulgated additional NSPS for the source category to regulate sulfur dioxide (SO_2) emissions from onshore natural gas processing plants (40 CFR part 60, subpart LLL).[48] In 2012, the Agency expanded requirements applicable to this source category by adding VOC standards for several oil and natural gas related operations emission sources not covered by 40 CFR part 60, subparts KKK and LLL, including natural gas well completions, centrifugal and reciprocating compressors, certain natural gas operated pneumatic controllers in the production and processing segments of the industry, and storage vessels in the production, processing, and transmission and storage segments.

For the first time in 2016, the Agency established requirements for certain equipment, processes, and operations across the Oil and Natural Gas Industry, including in the production, processing, and transmission and storage segments to address both GHG emissions (in the form of methane) in response to global climate change concerns, and VOCs.[49]

---

[46] 42 U.S.C. 7411(d)(2).
[47] 50 FR 26122 (June 24, 1985).
[48] 50 FR 40158 (October 1, 1985)
[49] 81 FR 35832 (June 3, 2016).

In September 2020, the EPA published two final rules to amend 2012 NSPS OOOO and 2016 NSPS OOOOa. The first is titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review.''[50] Commonly referred to as the 2020 Policy Rule, it first rescinded the regulations applicable to the transmission and storage segment on the basis that the 1979 listing limited the source category to the production and processing segments and that the transmission and storage segment is not "sufficiently related" to the production and processing segments, and therefore cannot be part of the same source category.[51] In addition, the 2020 Policy Rule rescinded methane requirements for the industry's production and processing segments on two separate bases. The first was that such standards are redundant to VOC standards for these segments.[52] The second was that the rule interpreted CAA section 111 to require, or at least authorize the Administrator to require, a pollutant specific "significant contribution finding" as a prerequisite to a NSPS for a pollutant, and to require that such finding be supported by some identified standard or established set of criteria for determining which contributions are "significant."[53] The rule went on to conclude that the alternative significant contribution finding that the EPA made in the 2016 Rule for GHG emissions was flawed because it accounted for emissions from the transmission and storage segment and because it was not supported by criteria or a threshold.[54, 55]

---

[50] 85 FR 57018 (September 14, 2020)
[51] See 85 FR 57027, 57029 (September 14, 2020).
[52] 85 FR at 57030 (September 14, 2020)
[53] 85 FR at 57034 (September 14, 2020).
[54] 85 FR 57038 (September 14, 2020).
[55] Following the promulgation of the 2020 Policy Rule, the EPA promulgated a final rule that identified a standard or criteria for determining which contributions are ''significant,'' which the D.C. Circuit vacated and remanded at the Agency's request following a change in administration. ''Pollutant-Specific Significant Contribution Finding for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories.''86 FR 2542 (January 13, 2021), vacated by *California* v. *EPA*, No. 21–1035 (D.C. Cir.) (Order, April 5, 2021, Doc. #1893155).

Published on September 15, 2020, the second of the two rules is titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration."[56] Commonly referred to as the 2020 Technical Rule, this second rule made further amendments to the 2016 NSPS OOOOa following the 2020 Policy Rule to eliminate or reduce certain monitoring obligations and to address a range of issues in response to administrative petitions for reconsideration and other technical and implementation issues brought to the EPA's attention since the 2016 NSPS OOOOa rulemaking. Specifically, the 2020 Technical Rule exempted low production well sites from fugitives monitoring (previously required semiannually), required semiannual monitoring at gathering and boosting compressor stations (previously quarterly), streamlined recordkeeping and reporting requirements, allowed compliance with certain equivalent State requirements as an alternative to NSPS fugitive requirements, streamlined the application process to request the use of new technologies to monitor for fugitive emissions, addressed storage tank batteries for applicability determination purposes and finalized several technical corrections. Because the 2020 Technical Rule was issued the day after the EPA's rescission of methane regulations in the 2020 Policy Rule, the amendments made in the 2020 Technical Rule applied only to the requirements to regulate VOC emissions from this source category. The 2020 Policy Rule amended 40 CFR part 60, subparts OOOO and OOOOa, as finalized in 2016. The 2020 Technical Rule amended the 40 CFR part 60, subpart OOOOa, as amended by the 2020 Policy Rule. The joint resolution disapproving the 2020 Policy Rule did not include or address the 2020 Technical Rule.

On November 15, 2021, the EPA published a proposed rule ("November 2021 Proposal") aimed at reducing GHG and VOC emissions from parts of the oil and natural

[56] 85 FR 57398 (September 15, 2020).

gas industry,[57] specifically the Crude Oil and Natural Gas source category.[58, 59] In the November 2021 Proposal, the EPA proposed new and updated standards of performance under CAA section 111(b) for GHGs (in the form of methane limitations) and VOC emissions from new, modified, and reconstructed sources (affected facilities) in this source category, as well as revisions to standards of performance for GHGs and VOC emissions already codified at 40 CFR part 60, subparts OOOO and OOOOa. The November 2021 Proposal also proposed EG under CAA section 111(d) for GHGs emissions (in the form of methane limitations) from existing sources (designated facilities).[60] The EPA also proposed several related actions in the November 2021 Proposal to address issues related to congressional disapproval of the 2020 Policy Rule under the Congressional Review Act in 2021. Lastly, in the November 2021 Proposal, the EPA proposed a protocol for OGI under the general provisions of 40 CFR part 60.

On December 6, 2022, the EPA published a supplemental proposed rule ("December 2022 Supplemental Proposal") that was composed of two main additions.[61] First, the EPA proposed further updates to NSPS OOOOb standards compared to those proposed in the November 2021 Proposal under CAA section 111(b) for GHGs (in the form of methane limitations) and VOC emissions from new, modified, and reconstructed facilities. Second, the EPA proposed further updates to the presumptive standards

---

[57] The EPA characterizes the oil and natural gas industry operations as being generally composed of four segments: (1) Extraction and production of crude oil and natural gas ("oil and natural gas production"), (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution. 89 FR 16841.

[58] *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*; Proposed Rule, 86 FR 63110 (November 15, 2021).

[59] The EPA defines the Crude Oil and Natural Gas source category to mean: (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station, commonly referred to as the "city-gate." 89 FR 16848.

[60] The term "designated facility" is defined as "any existing facility…which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility." 40 CFR 60.21a(b).

[61] *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*; Supplemental Notice of Proposed Rulemaking, 87 FR 74702 (December 6, 2022).

compared to those proposed for EG OOOOc in the November 2021 Proposal as part of the CAA section 111(d) EG for GHG emissions (in the form of methane limitations) from designated facilities. For purposes of EG OOOOc, the EPA also proposed implementation requirements for State plans developed to limit GHG pollution (in the form of methane limitations) from designated facilities in the Crude Oil and Natural Gas source category under CAA section 111(d).

On March 8, 2024, the EPA published the March 2024 Final Rule with multiple separate actions intended to reduce GHG and VOC emissions from the Crude Oil and Natural Gas source category.[62] First, the EPA finalized NSPS OOOOb regulating GHG (in the form of a limitation on emissions of methane) and VOC emissions for the Crude Oil and Natural Gas source category pursuant to CAA section 111(b). The NSPS codified in 40 CFR part 60, subpart OOOOb, are directly applicable to affected facilities that begin construction, reconstruction, or modification after December 6, 2022. Second, the EPA finalized the EG in OOOOc to limit GHG emissions. The EG codified in 40 CFR part 60, subpart OOOOc, applies to States in the development, submittal, and implementation of State plans to establish performance standards to reduce emissions of GHGs from designated facilities that are existing sources on or before December 6, 2022. Third, the EPA finalized several related actions (including final amendments to NSPS OOOOa stemming from congressional disapproval of the 2020 Policy Rule under the Congressional Review Act in 2021. Fourth, the EPA finalized a protocol under the General Provisions for OGI. The March 2024 Final Rule became effective on May 7, 2024, 60 days after publication in the *Federal Register*.

On August 1, 2024, the EPA published an IFR that made minor and non-substantive corrections to the March 2024 Final Rule in order to correct identified

[62] 89 FR 16820 (March 8, 2024).

inadvertent errors.[63] After publication of the March 2024 Final Rule, the EPA identified, through its own internal reassessment of the regulatory text, as well as through communications with stakeholders and the Office of the Federal Register, erroneous cross-references and typographical errors within the regulatory text. Through those same processes, the EPA also identified the need for some minor wording changes to clarify erroneous language (or, in some cases, erroneous omissions) in the regulatory text, and to ensure that the regulatory text aligns with the descriptions of the relevant provisions in the March 2024 Final Rule preamble and other parts of the regulation(s).

Further, after the publication of the March 2024 Final Rule, the EPA received multiple petitions for reconsideration.[64] On May 6, 2024, the EPA notified certain petitioners and the public that reconsideration had been granted on two narrow and discrete aspects of the March 2024 Final Rule: The temporary flaring provisions for associated gas in certain situations; and the vent gas NHV continuous monitoring requirements an alternative performance test (sampling demonstration) option for flares and enclosed combustion devices.[65] On January 15, 2025, the EPA proposed amendments for this Reconsideration and finalized amendments for this Reconsideration on April 9, 2026.[66, 67]

On July 31, 2025, the EPA issued an IFR that extended deadlines for certain provisions related to control devices, equipment leaks, storage vessels, process controllers, and covers and CVS in the NSPS OOOOb.[68] The EPA also extended the date for future implementation of the Super Emitter Program. Finally, the EPA extended the State plan submittal deadline in the EG OOOOc. On December 3, 2025, the EPA promulgated a final rule reaffirming the extensions established in the July 2025 IFR,

---

[63] 89 FR 62872 (August 1, 2024).
[64] *See* Docket No. EPA-HQ-OAR-2025-0163 for petitions for reconsideration received.
[65] *See* Docket No. EPA-HQ-OAR-2025-0163 for May 6, 2024, letter granting reconsideration.
[66] 90 FR 3743 (January 15, 2025).
[67] 91 FR 18056 (April 9, 2026).
[68] 90 FR 35966 (July 31, 2025).

which extended several compliance deadlines in the NSPS OOOOb and EG OOOOc.[69] In addition to reaffirming the extensions in the July 2025 IFR, the EPA further extended the deadline for the NHV continuous monitoring requirements and for the alternative performance test (sampling demonstration) option for flares and enclosed combustion devices and also extended the compliance deadline related to the initial annual reporting deadline.

This proposal is based on a record-focused reevaluation of certain determinations made in the March 2024 Final Rule. The EPA is proposing this action to provide near-term relief from certain regulatory requirements it now believes are predicated on erroneous BSER determinations, are not achievable, and/or are otherwise unreasonable. Addressing these issues in the near term is necessary to provide much needed clarity to new sources regulated under NSPS OOOOb, and to existing sources that will be subject to state plans under EG OOOOc, given the compliance deadlines and implementation schedules set in the March 2024 Final Rule, as subsequently extended.

The EPA acknowledges that stakeholders have also raised concerns about the Agency's underlying statutory authority to regulate GHG emissions from the Oil and Natural Gas source category under CAA section 111. In a separate and ongoing rulemaking for a distinct source category, the Agency is addressing statutory authority issues associated with its regulation of GHG emissions from fossil fuel-fired power plants under CAA section 111.[70] That rulemaking raises issues with respect to the scope of the Agency's authority under CAA section 111 but does not encompass or address NSPS or

---

[69] 90 FR 55671 (December 3, 2025).

[70] *See* 91 FR 59002 (September 17, 2026); 90 FR 25752 (June 17, 2025). The EPA recently finalized a record-focused reevaluation and repeal of certain BSER determinations and associated standards for fossil fuel-fired power plants based on the alternative proposal presented in the June 2025 proposed rule. *See* 91 FR 58954 (September 17, 2026). The EPA has not yet taken final action on the primary proposal in the June 2025 proposal rule and intends to consider the statutory authority issues raised in that aspect of the proposed rule together with statutory authority issues raised in the Agency's recent supplemental proposal in a forthcoming final action addressing the Agency's authority to regulate GHG emissions from the fossil fuel-fired power plant source category.

EG for the Crude Oil and Natural Gas source category, which operate in a distinct manner, have their own regulatory history, and involve different and additional considerations. Pending completion of the separate rulemaking addressing the EPA's statutory authority with respect to GHG emissions from the fossil fuel-fired power plant source category, the Agency would then address in a future rulemaking, as appropriate, the extent to which the conclusions in such action with respect to the Agency's statutory authority under CAA section 111 require revisions to the oil and gas regulations at 40 CFR part 60, subparts OOOOa, OOOOb and OOOOc.

III. Summary and Rationale of Proposed Amendments to NSPS OOOOb and EG OOOOc

Sections III.A through III.K of this preamble present the background, the summary of proposed changes, and rationale for proposed amendments to the March 2024 Final Rule.

A. Super Emitter Program

As part of the March 2024 Final Rule, the EPA established a novel form of work-practice standard and compliance assurance mechanism known as the Super Emitter Program, which relies on third-party entities certified by the Agency to detect "very large emissions events"[71] using Agency-approved technologies and submit notifications to EPA personnel. The EPA transmits the third-party notification to relevant owners and operators, thereby triggering an obligation to investigate and to take any necessary corrective actions required under applicable standards. The EPA finalized this program as part of the 40 CFR part 60 NSPS subparts OOOO, OOOOa, and OOOOb and as part of the presumptive requirements applicable to state plans under EG OOOOc, meaning that States are expected to establish super emitter programs analogous to the EPA's. Upon

[71] 89 FR 16825 (March 8, 2024).

reconsideration, the EPA no longer believes that the Super Emitter Program is well-grounded in policy and law and proposes to rescind the third-party certification, notification, and other related provisions in NSPS OOOO, OOOOa, and OOOOb and EG OOOOc.

In Section III.A.1 of this preamble, the EPA explains its initial conception of the program in the December 2022 Supplemental Proposal, comments received on this initial conception, and changes made to the program by the Agency in the March 2024 Final Rule. In Section III.A.2, the EPA explains the multiple potential bases for the proposed rescission of the Super Emitter Program. First, the EPA proposes to rescind the Super Emitter Program on policy grounds, including because the program has failed to meet the expectations the Agency had when it finalized the program in March 2024 and is unnecessary and ineffective. Second, the EPA also proposes to rescind the Super Emitter Program for legal reasons. While the EPA solicits comment on this proposal within this section, table 34 in section VII also summarizes all solicitations for comment for convenience.

1. Background

In the December 2022 Supplemental Proposal, the EPA sought public comment on a novel program intended "to trigger swift mitigation of super-emitter emissions events when they are identified through credible information provided by regulatory authorities or approved qualified third-party sources."[72] The EPA explained that it believed additional action was needed to address "super-emitter emissions events" citing one study finding "that the top five percent of sources contribute over 50 percent of the total emissions" from the source category, although it also acknowledged that results

[72] 87 FR 74706 (December 6, 2022); *id.* at 74706 n.5 (noting that the November 2021 Proposal "solicited comment on the use of information collected by communities and others to address large emissions events").

"vary by basin."[73] This program, referred to at the time as the "super-emitter response program," adopted the concept of "Super-Emitters"—sources for which detected emissions are 100 kilograms per hour (kg/hr) or greater—and proposed a BSER of "[r]oot cause analysis and corrective action following notification of super-emitter emissions event."[74] The EPA believed that the proposed requirements in the November 2021 Proposal and December 2022 Supplemental Proposal, "when implemented correctly, would result in reducing the number of super-emitter emissions events," but further proposed the "super emitter response program as a backstop to address the large contribution of super-emitters" to sector emissions. The EPA proposed two statutory bases for the program: first, that "super-emitters" are "a separate and distinct source of emissions" (and therefore a "designated facility"); and second, that the program "constitutes work practice standards for certain sources and compliance assurance mechanisms for other sources."[75]

The proposed "super emitter response program" generated significant public comment. As relevant here, certain commenters argued that the EPA lacked statutory authority to treat super-emitter events as an "affected facility" subject to standards separate and apart from affected facilities subject, on their own terms, to either the NSPS OOOO, OOOOa, and OOOOb or EG OOOOc.[76] Commenters raised concerns that this first-of-its-kind program would create regulatory obligations based on monitoring conducted by unaffiliated third parties, that the EPA had not clearly explained an adequate legal basis for the proposed program, and that the EPA had not explained how

---

[73] 87 FR 74746 (December 6, 2022). Specifically, the EPA relied upon a March 2022 aerial survey of methane emissions in the New Mexico Permian Basin. *See id.* 74746 n.99 (citing Yuanlei Chen et al*.,* "Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey," *Environmental Science and Technology,* Vol. 56, No. 7 (March 2022)).
[74] 87 FR 74708, 74711 (December 6, 2022).
[75] 87 FR 74712 n.9, 74752-54 (December 6, 2022).
[76] API Comments on NSPS OOOOb and EG OOOOc 2022 Supplemental Proposal. February 13, 2023. EPA-HQ-OAR-2021-0317-2428. pg 98; and AXPC Comments on the 2022 Supplemental Proposal. February 13, 2023. EPA-HQ-OAR-2021-0317-2326. pg. 28.

the program was consistent with the statute's specific provision for citizen enforcement in CAA section 304.[77] Commenters also argued that the EPA had not justified the 100 kg/hr threshold or explained how that threshold would work in practice given the short duration of super-emitter events and attribution difficulties.[78]

The EPA finalized the program, with revisions, as the Super Emitter Program in the March 2024 Final Rule. The Agency reaffirmed its view that the program would be an additional tool to address super-emitter events, which it found may "contribute almost 50 percent of the methane emissions in the oil and gas sector."[79] The Super Emitter Program was thus designed to serve as a backstop and a complement to other requirements of the NSPS OOOO, OOOOa, OOOOb, and EG OOOOc regulatory program to address large methane super-emitter events by directing operator attention to potential problems and to provide feedback to the EPA about the effectiveness of other regulatory requirements. The EPA defined a super-emitter event in 40 CFR part 60 subparts OOOO, OOOOa, OOOOb and EG OOOOc as "any emissions event that is located at or near an oil and natural gas facility (*e.g.*, individual well site, centralized production facility, natural gas processing plant, or compressor station) and that is detected using remote detection methods and has a quantified emission rate of 100 [kg/hr] of methane or greater."[80] In response to public comments, the EPA clarified that its statutory authority for the program was CAA section 114(a), which authorizes the Agency to require "'any person who owns or operates any emission source' (except mobile sources) to provide information necessary for purposes of carrying out the CAA

---

[77] API Comments on NSPS OOOOb and EG OOOOc Supplemental Proposal. February 13, 2023. EPA-HQ-OAR-2021-0317-2428. pg 97; Texas Oil & Gas Association (TXOGA). (2022). "Comments on New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review; Proposed Rule." January, 31, 2022. Pgs. 32-33; and TXOGA Comments of the 2022 Supplemental Proposal. EPA-HQ-OAR-2021-0317-2202. pg. 10.
[78] API Comments on NSPS OOOOb and EG OOOOc Supplemental Proposal. February 13, 2023. EPA-HQ-OAR-2021-0317-2428. pg 99.
[79] 89 FR 16977 (March 8, 2024).
[80] 40 CFR 60.5371, 60.5371a, 60.5371b, 60.5388c.

and its authority to regulate sources under CAA section 111."[81] The EPA further clarified that it would not treat super-emitter events as a distinct "affected facility" but was instead finalizing that the Super Emitter Program is "an additional work practice standard … for fugitive emissions at well sites, centralized production facilities and compressor stations" and as "an additional compliance measure" for "affected facilities" subject to NSPS OOOO, OOOOa, OOOOb, and EG OOOOc.[82]

The EPA made changes to the Super Emitter Program from proposal in response to commenter objections about the role of unaffiliated third parties. Where an identified super-emitter event is attributable to a source regulated under CAA section 111 (NSPS OOOO, OOOOa, or OOOOb, or a state or Federal plan implementing EG OOOOc), the owner or operator is responsible for taking action in response to such notifications in accordance with the applicable regulation. Rather than authorizing certified third parties to send notifications to potential sources directly, the final regulations instead route notifications through the EPA in the first instance. Under 40 CFR 60.5398b(d), the EPA approves the remote-sensing technologies that may be used to identify relevant emissions events, and, consistent with the implementing regulations, may certify and de-certify third party notifiers. Certified third party notifiers may submit information to the EPA that they have collected about potential super-emitter events using EPA-approved remote-sensing technology in the form of a notification that is timely submitted and contains certain specified information on the methane release.[83] The EPA then reviews the submission, and if it determines that the submission is complete and does not contain information that it finds to be inaccurate to a reasonable degree of certainty, the EPA will provide the notification to the owner or operator of the relevant facility and make the notification publicly available on an EPA website, without owner or operator

[81] 89 FR 16877 (March 8, 2024) (quoting 42 U.S.C. 7414(a)).
[82] *Id.*; *see also id.* at 16877-78.
[83] *See* 40 CFR 60.5371b.

attribution.[84] Under these provisions, owners and operators of facilities who receive notifications from the EPA who own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification, are required to initiate an investigation of any identified potential large methane emissions events at their site, report to the EPA the results of the investigation, and, if necessary, repair any leaks covered by certain requirements. Owners and operators of facilities who receive notifications from the EPA but who do not own or operate an oil and natural gas facility within 50 meters from the latitude and longitude provided in the notification, would report this to the EPA and no further action is required.[85] The EPA then posts the reports from the owners and operators on the same EPA website, including owner or operator attributions that were confirmed by the report.[86]

Subsequent to the March 2024 Final Rule, several reconsideration petitioners continued to raise concerns about the Super Emitter Program. The EPA has received few requests for third party or technology certification, and as explained further below, now agrees with concerns raised during the prior rulemaking that the short duration of such events and established threshold render the program difficult to implement and ineffective at proactively addressing such events. In addition to those concerns, the EPA has experienced unanticipated difficulties and concerns in implementing this new program. To address those concerns, the EPA included in the 2025 IFR an extension of the date for future implementation of the Super Emitter Program until January 22, 2027. In a final action published on December 3, 2025, the EPA considered public comments on the extensions for the Super Emitter Program and reaffirmed the extensions.[87]

2. Summary of Proposed Rescission and Rationales

---

[84] *Id.*; s*ee also* 40 CFR 60.5371, 60.5371a, and 60.5388c.
[85] *See, e.g.*, 40 CFR 60.5371(a)(1), 60.5371a(a)(1), 60.5371b(d)(1), and 60.5388c(a)(1).
[86] *See, e.g.*, 40 CFR 60.5371b.
[87] 90 FR 55671 (December 3, 2025).

The EPA is proposing to rescind the Super Emitter Program on several alternative policy and legal bases. First, the EPA now proposes that this novel program rests on insufficient evidence of the nature and duration of super-emitter events, defined as emissions of 100 kg/hr or greater, and that the same concerns that led the Agency to decline to treat "super emitters" as a distinct "affected source" call into question the conceptual basis and need for the program in the first instance. Second, the EPA further proposes that the program is not necessary and provides limited additional value in light of the other requirements applicable to affected sources under NSPS OOOO, OOOOa, OOOOb, and EG OOOOc. Third, the EPA proposes that the Super Emitter Program is not effective and is overly broad as designed. Fourth, the EPA proposes that the statutory authority bases finalized in the March 2024 Final Rule are inadequate to maintain the program. Specifically, as explained below, the EPA has concerns that the program features an inappropriate role for third parties, does not properly function as a work practice standard, and does not properly function as a compliance measure.

If finalized, the proposed rescission would remove provisions related to the Super Emitter Program, including for certification and decertification of third parties, certification and decertification of third-party monitoring technologies, and a source's obligations to respond in the event of a notification received pursuant to the Super Emitter Program, from 40 CFR part 60, subparts OOOO, OOOOa, OOOOb, and OOOOc.

The EPA proposes that additional information and further study are required to evaluate the underlying premise of the Super Emitter Program, that is, the assertion that "super-emitter events" (defined as emissions of 100 kg/hr or greater) from a select few sources are responsible for the majority of source-category emissions. In the March 2024 Final Rule, and specifically in the December 2022 Supplemental Proposal, the EPA believed that "the top five percent of sources contribute to over 50 percent of the total

emissions" from the source category because of super-emitter events.[88] For this conclusion, the Agency relied on a single study consisting of 2018-2020 aerial surveys of the New Mexico Permian Basin that acknowledged its results departed from those in previous studies and did not endeavor to differentiate among the regulatory status of emission sources or potential causes for the emissions. While informative, the novel analytical approach and results of this study had not been thoroughly vetted at the time of the December 2022 Supplemental Proposal, and the EPA did not revisit the question of the study's quality and utility in the March 2024 Final Rule. Indeed, the Agency acknowledged at the time that results vary by basin and involve a number of different potential causes and explanations depending on the nature and regulatory status of the potential source(s).[89] At the time of the March 2024 Final Rule, the EPA did not have adequate information on the prevalence, nature, duration, and cause of large emission events, without which the program cannot effectively further legitimate policy ends, and thus, the EPA proposes to rescind the Super Emitter Program. While the Agency is aware of some additional information that has become available on this topic since the March 2024 Final Rule, the Agency proposes to conclude that information indicates that the Super Emitter Program is overly broad as designed, as explained below, which is a separate reason for its proposed rescission. The Agency specifically seeks comment providing additional studies and information bearing on super-emitter events and corresponding strategies to address them, including whether the EPA should treat them separately as a regulatory manner in the first instance and, if so, whether and which threshold the EPA should use to separately consider such events. (Question III.1a)

Separately, the EPA no longer believes that the Super Emitter Program is necessary in light of the emission-limitation, monitoring, and mitigation requirements

[88] 87 FR 74746-47 (December 6, 2022).
[89] *Id.*

applicable to affected sources. As described in the record for the March 2024 Final Rule, the program was finalized as an additional work practice standard under NSPS OOOOb (and presumptive standard under EG OOOOc), and as an additional compliance assurance measure for other NSPS OOOOb affected facilities, NSPS OOOO and OOOOa affected facilities, and designated facilities under EG OOOOc. The Agency asserted at the time that the program could be a helpful supplement to requirements already applicable to affected facilities because super-emitter events are unpredictable and may not be detected immediately, and thus the Agency believed that providing timely notifications of them to operators could assist in addressing these events. [90] However, the EPA also concluded that the NSPS requirements and EG presumptive standards included in the March 2024 Final Rule would prevent large emission events (*e.g.*, design and operation requirements for flares) or detect and mitigate most of these large emissions events (*e.g.*, through regular monitoring for fugitive emissions)[91] and did not explain why the Super Emitter Program was necessary as a work-practice standard or compliance assurance mechanism for affected facilities already required to identify and correct aberrant emissions events.

Even considering the amendments proposed in this proposed rule, the EPA continues to believe that other requirements in the NSPS OOOOb and the EG OOOOc will be more than sufficient to prevent, detect, and mitigate most large emission events that would be within the scope of the Super Emitter Program. Those requirements include, for example, zero-emissions standards for process controllers at high production sites and design and operation requirements for flares, combined with regular monitoring for fugitive emissions, process upsets on tanks, and malfunctioning controllers. For example, many of the persistent super-emitter events identified in recent studies are from

[90] 87 FR 74748 (December 6, 2022).
[91] 87 FR 74747 (December 6, 2022).

flares and tank systems[92, 93] and the other compliance assurance requirements in the March 2024 Final Rule address several issues that may lead to these types of large emission events. These include compliance assurance requirements for flares and enclosed combustors that include a requirement for a continuous burning pilot flame that must be confirmed through monthly visual emissions testing or the continuous use of video surveillance cameras.[94] Real-time monitoring or monthly testing is expected to be sufficient to detect malfunctioning flares and support compliance with the applicable requirements, making the possible detection of such emissions by a third-party unnecessary from a compliance assurance perspective. As these examples illustrate, provisions in the March 2024 Final Rule are expected to prevent many such events and provide timely and actionable information on events that would be within the scope of the Super Emitter Program, as well as adequately supporting operators to identify such events.

Along with these provisions, the Alternative Test Method (ATM) program is expected to further support the identification of super-emitter events. Under that program, owners and operators have the option to use EPA-approved advanced methane detection and measurement systems to complete the required monitoring. There are currently 18 approved alternative technologies that include periodic airborne remote sensing surveys that can detect super-emitter events and lower-level emissions with improved accuracy and source specificity compared to most satellite techniques.[95] Importantly, these survey approaches provide actionable emission event data directly to the operator, greatly

---

[92] Cusworth D.H. et al. (2026). Duration of super-emitting oil and gas methane sources. Nat Commun. 2026 Jan 24;17(1):2011. doi: 10.1038/s41467-026-68804-7. PMID: 41580397; PMCID: PMC12936207. https://pubmed.ncbi.nlm.nih.gov/41580397/

[100] Cusworth, D.H. et al. (2021). Intermittency of Large Methane Emitters in the Permian Basin. *Environ. Sci. Technol. Lett.* 13 July 2021; 8 (7): 567–573. https://doi.org/10.1021/acs.estlett.1c00173https://doi.org/10.1021/acs.estlett.1c00173

[94] The EPA is not proposing to amend these requirements in this proposed rule.

[95] Information on EPA-approved alternative technologies can be found at; https://www.epa.gov/emc/oil-and-gas-alternative-test-methods

reducing lag time associated with EPA notification under the current Super Emitter Program. In addition to periodic monitoring options, emerging semi-continuous monitoring approaches utilizing 24/7 onsite sensing techniques may be able to provide rapid detections of high emitter events yielding enhanced diagnostic capability for operators. Because monitoring under the ATM program is site specific, the emission information delivered is directly relevant to the affected source categories. With monthly, bimonthly, or quarterly monitoring requirements (depending on technology sensitivity), the ATM program provides an effective check for super-emitter events. Based on the ATM program application rate, the EPA anticipates increased participation in the program over time, which can support the timely identification of super-emitter events.

In addition, the EPA no longer believes, given experience with implementation of the program and the limited additional information in the scientific literature, that the Super Emitter Program is effective in addressing the events the Agency previously feared would not be adequately captured or addressed by other requirements due to implementation issues and the overly broad nature of its design. As noted in the 2025 IFR, the EPA experienced unanticipated difficulties and concerns in implementing the Super Emitter Program. In the 2025 IFR, the EPA explained that the third-party notifier is not required to provide attribution of who owns or operates a site. In practice this has meant the EPA needed to identify the owner/operator before it can provide them with the notification, reducing the ability of the EPA to provide timely notification of these events to the owner/operator. Additional Super Emitter Program implementation issues have impacted the overall anticipated effectiveness of the program. For example, the Agency expected that the program would generate sufficient interest from multiple third-party notifiers and that data collected using the EPA-approved remote sensing technologies (*e.g.*, satellites) would lead to expeditious and effective mitigation of super-emitter events by owners and operators. As stated in the March 2024 Final Rule, in response to

comments, the EPA emphasized that the Super Emitter Program would only authorize third parties to use remote sensing technologies, not technologies that would require close access to such facilities. The EPA specifically identified satellites and aircraft as technologies that would play a fundamental role in the ATM program. At the time of the March 2024 Final Rule publication, several satellites capable of detecting methane were already in operation and additional satellites, including commercial and non-profit satellites were anticipated to be launched. The Agency expected that the availability of these systems would contribute to providing the broad coverage essential to the effectiveness of the ATM program as a compliance assurance tool. The EPA anticipated that the participation of third parties with a range of remote sensing technologies would strengthen the ATM program's ability to identify large emission events and thereby support compliance with NSPS OOOO, OOOOa, OOOOb and the EG OOOOc presumptive standards. However, the EPA only received three technology applications from remote sensing companies for use in the Super Emitter Program, since the program began accepting applications in March 2024.[96] Additionally only one entity has requested and become a certified third party under the Super Emitter Program.[97] With only one third party certified and no other entities requesting third party certification, the Program is not expected to achieve the coverage originally envisioned and thus, would not function as the effective compliance assurance tool.

In addition, with respect to the program's scope, the EPA notes that the Super Emitter Program, as designed, is overly broad, mostly capturing permissible events where no action is required or other short-term events that have already been resolved and thus, would not be effective in addressing events the Agency previously feared would not be adequately captured or addressed by other requirements. In the March 2024 Final Rule,

[96] Third-Party Certifications. https://www.epa.gov/emc/third-party-certifications
[97] https://www.epa.gov/system/files/documents/2025-01/matm001-carbon-mapper-aerial-survey.pdf.

the EPA finalized requirements that the notification must be supplied to the EPA within 15 days after the detection event in order to provide actionable information to owners or operators.[98] However, early program implementation experience demonstrated that, in most cases where the EPA issued a notification under the Super Emitter Program (six out of seven total notifications sent), the owner or operator received the notification after the event had ended. This aligns with a recent study, which indicates that most super-emitter events persist only for short periods, typically on the scale of hours, and are often attributable to routine process or maintenance events.[99] Given the inherent lag between the occurrence of a large emission event, the detection and attribution process, and the operator's receipt of a notification, many notifications from the Super Emitter Program would be expected to arrive after the event has already been resolved. Although at the time of the March 2024 Final Rule, the EPA understood that many large emission events are intermittent events,[100] the Agency now expects that in the majority of cases, the notifications will pertain to these types of events instead of focusing on events that the EPA was previously concerned would not be mitigated by the other provisions in the NSPS OOOO, OOOOa, OOOOb, OOOOc and the emission guidelines. Additionally, the delay between event identification and notification, resulting in notifications that arrive well after the event has ended, can create additional practical challenges for operators attempting to determine the cause of the event identified. Based on these factors together with the minimal third-party participation, the EPA proposes to conclude that the Super Emitter Program, as designed, is not effective. The EPA's proposal regarding the program's lack of effectiveness alters the EPA's understanding of the significance of the burden on owners/operators due to requirements to respond to notifications about

---

[98] 89 FR 16920 (March 8, 2024)
[99] Cusworth, D.H., et al. (2026). Duration of super-emitting oil and gas methane sources. Published online: January 24, 2026. Nat Commun. 2026 Jan 24;17(1):2011. doi: 10.1038/s41467-026-68804-7. PMID: 41580397; PMCID: PMC12936207. https://pubmed.ncbi.nlm.nih.gov/41580397/
[100] 89 FR 16904, 16920 (March 8, 2024)

permissible activities. If the Program cannot reliably distinguish true super emitter events from permissible releases or routine maintenance activities, operators may be required to use resources to respond to notifications for which no corrective action is required, such as gas well liquids unloading events.

For these reasons, the EPA proposes to conclude that the Super Emitter Program is not necessary to retain and does not function effectively as a compliance assurance tool. To the extent that the Administrator believes additional information is required to help assure compliance with, or identify potential violations of, requirements under the CAA and its implementing regulations, or otherwise seeks to obtain additional information on super-emitter events, the EPA may rely on other information collection or compliance assurance tools, such as CAA section 114 information collection requests under the authority expressly provided under the CAA. Further, anyone who wishes to submit information to the EPA about methane releases remains free to do so, even without the mechanism of the Super Emitter Program.

The EPA further proposes, as a separate potential basis for repeal, that portions of the Super Emitter Program lack an adequate legal basis under the CAA. At the very least, the EPA did not fully articulate a clear legal basis for all portions of the program in the March 2024 Final Rule. The EPA explained its legal authority for establishing the program in this way:

> [T]he EPA's authority to require sources (regardless of whether those sources are regulated under CAA section 111) to investigate potential sources of super-emitter events and report to the EPA is CAA section 114. The EPA's authority to require regulated sources to repair or otherwise address the cause of the super-emitter event is CAA section 111. In particular, for sources regulated under CAA section 111, the Super Emitter Program will serve as: (1) an additional work practice standard under NSPS OOOOb (and presumptive standard under EG OOOOc) for fugitive emissions at well sites, centralized production facilities and compressor stations, and as (2) an additional compliance assurance measure for other NSPS OOOOb affected facilities, NSPS OOOO and OOOOa affected facilities, and designated facilities under EG OOOOc.[101]

[101] 89 FR 16877.

Despite this broad assertion of authority, certain regulatory provisions at the heart of the program do not appear to be authorized by either CAA section 111 or 114.

First, CAA section 114 is comprised of a few different, but interlocking, elements. CAA section 114(a)(1) specifies that the EPA "may require any person who owns or operates any emission source, who manufactures emission control equipment or process equipment, who the Administrator believes may have information necessary for the purposes set forth in this subsection, or who is subject to any requirement of this chapter," (except for manufacturers subject to certain title II requirements, who are subject to CAA section 208), to produce and provide certain information. These are the groups of "person[s]" from whom the EPA can collect information under CAA section 114. Further, CAA section 302(e) defines "person" to include "an individual, corporation, partnership, association, State, municipality, political subdivision of a State, and any agency, department, or instrumentality of the United States and any officer, agent, or employee thereof."

Second, CAA section 114 specifies that the EPA may require "any person," in one of the groups described above, to "establish and maintain such records… make such reports… install, use, and maintain such monitoring equipment… sample such emissions… keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical… submit compliance certifications… and… provide such other information as the Administrator may reasonably require."[102] Third, with respect to the timing, or frequency, of data collection, CAA section 114(a)(1) specifies that the EPA may require this information "on a one-time, periodic or continuous basis." And fourth, CAA section 114(a) specifies that the EPA may collect information in accordance with the parameters explained above for the

[102] 42 U.S.C. 7414(a)(1)(A)–(G).

purposes of: (i) developing or assisting in the development of any implementation plan under CAA sections 110 or 111(d), or any emission standard under CAA sections 111 or 112 or any regulation under CAA section 129; (ii) determining if any person is in violation of any such standard or any requirement of an implementation plan; or (iii) "carrying out any provision" of the CAA (with the exception of certain provisions under title II of the CAA).

When describing the Super Emitter Program, the first several "major elements" of the program that the EPA listed do not appear to fit within the framework laid out by CAA section 114.[103] These elements include (a) qualifications for third-party notifiers, (b) third-party notifier certification, and (c) notifications of super-emitter events (which includes a description of self-imposed EPA regulatory obligations). For purposes of NSPS OOOOb, these elements can be found in the regulations at 40 CFR 60.5371b(a), (b), and (c), respectively. As previously noted, the March 2024 Final Rule also required States to establish comparable programs.

While all components of the Super Emitter Program were designed to work together, the first two elements are closely related. The first element of the program includes the regulations regarding qualifications for third-party notifiers, which state that "[a]n entity may apply…for approval as a third-party notifier."[104] The second element is a lengthy regulatory provision detailing the certification, and de-certification, process for third-party notifiers, and states that "[a]n entity…may apply to be certified as a third-party notifier."[105] Neither of the regulatory provisions for these program elements appear to fit within the ambit of CAA section 114 because both provisions involve voluntary actions. No entity is required to become, or apply to become, a certified third-party notifier. While CAA section 114 allows the EPA to require certain information from

[103] 89 FR 16879-80.
[104] 40 CFR 60.5371b(a).
[105] *Id.* 60.5371b(b).

certain entities under certain conditions, it does not speak to establishing criteria and procedures for the certification, and de-certification, of entities who might *voluntarily* choose to provide information to the EPA. CAA section 114 states that the EPA "Administrator may require" certain entities to complete enumerated tasks and provide certain information, but these provisions do not require anyone to do anything; they merely list criteria and a process to become "certified" to submit information to the EPA if an entity so desires. This voluntary certification process is not contemplated by CAA section 114. As such, these regulations do not appear to fit within the scope of EPA's authority under CAA section 114. Nor do they appear to justify requiring States to establish comparable programs. To be clear, the Super Emitter Program did not change the ability of any person to submit any information they would like to the EPA at any time outside the auspices of the program, and no such certification or particular qualifications are required for such submissions.

Further, the record for the March 2024 Final Rule provides no explanation of how these provisions derive authority from CAA section 114. The closest explanation in the March 2024 Final Rule states that "[i]t is the EPA's long-standing position that 'information will be considered to have been provided . . . under section 114 of the Act . . . if its submission could have been required under section 114. . . .'"[106] But this statement relates to whether the EPA could require the submission of information on a super-emitter event from a third party, not whether CAA section 114 provides authority to establish criteria and processes regarding the voluntary submission of information.

Likewise, 40 CFR 60.5371b(c) does not appear to fit within EPA's authority under CAA section 114. Most relevant here, that provision binds the EPA to take certain actions triggered by the submission of a notification to the Agency from a certified third party. For example, it requires that "[t]he EPA will review the submitted notifications"

[106] 89 FR 16916 (quoting 40 CFR 2.301(b)(2)).

and that "EPA will assign the notification" a report number.[107] Similarly, the introductory text in 40 CFR 60.5371b imposes obligations on the EPA by stating that the agency "shall" review notifications received from certified third parties, assign the notification an identification number, and post information on an EPA webpage. CAA section 114 does not appear to contemplate EPA authority to promulgate a regulation or establish procedures that obligate the agency to take certain steps upon action from parties outside the EPA. Thus, these provisions appear to be outside the scope of EPA's authority under CAA section 114.

In addition to CAA section 114, in the March 2024 Final Rule, the EPA stated that the legal authority for the Super Emitter Program also derived from CAA section 111 in two respects: as an additional work practice standard and as an additional compliance assurance measure. However, the same regulatory provisions discussed above do not appear to fit within either category under CAA section 111. First, the EPA stated that it had "incorporated the Super Emitter Program, in particular the requirement to repair fugitive emissions components that are sources of super-emitter events, as a part of the BSER and therefore work practice standards for fugitive emissions components affected/designated facilities under NSPS OOOOb/EG OOOOc."[108] The EPA's discussion of this issue in the March 2024 Final Rule is limited and does not explicitly take the position that third-party certification, criteria for certification, or EPA's self-imposed regulatory obligations are themselves part of the "best system of emission reduction" for an affected source. Put another way, the regulations at 40 CFR 60.5371b(a)-(c), which establish the process for certifying third-party notifiers, do not seem to flow from the EPA's standard-setting authority in CAA section 111 as none of these processes appear to be part of the "standard of performance" as defined by CAA

[107] 40 CFR 60.5371b(c).
[108] 89 FR 16878 (March 8, 2024).

section 111(a)(1). Again, these processes are all voluntary in the sense that no entity is required to apply to the EPA to become a certified third-party notifier, and no certified third party is required to send the EPA any notifications under the Super Emitter Program. The March 2024 Final Rule contains no explanation of how the EPA's standard-setting authority could be the source of authority for these voluntary processes.

The EPA acknowledges that "[e]missions from certain fugitive emissions components can be significant (as one example, a stuck-open thief hatch) and can remain undetected until the next scheduled periodic monitoring."[109] However, we now propose to conclude that the Super Emitter Program is not essential to addressing those emissions (*i.e.*, it is not necessary to utilize the program as an additional work practice standard) because there are already mechanisms in the regulations to address such emissions when they become known to owners and operators of affected sources. For example, 40 CFR 60.5397b(h) requires the repair of "each identified source of fugitive emissions" regardless of when the source of the fugitive emissions is identified. In addition, 40 CFR 60.5370b(b) requires that owners and operators "[a]t all times… maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions."[110]

Moreover, CAA section 111 does not provide legal authority to establish the Super Emitter Program's certification procedures as an additional compliance assurance measure. In the March 2024 Final Rule, the EPA asserted that the Super Emitter Program would serve as a compliance assurance measure for sources that are not fugitive emissions components affected/designated facilities under NSPS OOOOb/EG OOOOc. The EPA reasoned that, although design, operational, monitoring, recordkeeping, and reporting requirements under other applicable sources of law already obligated such

---

[109] *Id.*
[110] *See also* 40 CFR 60.11(d).

sources to identify and correct emissions events, super-emitter events "are unpredictable" and "can occur between routine inspections and release significant emissions in a short span of time."[111] The EPA then concluded that the Super Emitter Program could "serve as an additional source of monitoring data to inform and alert owners and operators" to check for compliance with applicable Federal or State requirements.[112] However, each standard within the March 2024 Final Rule already has its own set of compliance assurance mechanisms to ensure compliance with the applicable standards. Further, if a source owner or operator becomes aware that they might be operating out of compliance, it is in their interest to investigate and take corrective action, if needed. As previously noted, the processes and criteria for certifying third-party notifiers do not themselves ensure compliance with any standard, so CAA section 111 does not appear to provide authority for 40 CFR 60.5371b(a)-(c).

Finally, the EPA proposes that the Super Emitter Program was not contemplated by the citizen-enforcement provision in CAA section 304—the provision of the statute (in addition to public-participation requirements) in which Congress addressed the role of citizens in implementation of the CAA. Notifications submitted by third parties pursuant to the Super Emitter Program are sent to the EPA in the first instance, where they undergo an initial EPA review, and are then transmitted by the EPA to relevant owners and operators. However, the EPA is concerned that the third-party certification and notification procedures could improperly elevate certain unaffiliated third parties over others and confer special status that Congress did not contemplate in any provision of the CAA. Under CAA section 304, citizens may bring actions on their own behalf alleging any violation of applicable standards, including those in NSPS OOOO, OOOOa, OOOOb, or EG OOOOc, to the extent those standards have been implemented and are

---

[111] *Id.*
[112] *Id.*

federally enforceable. In authorizing such actions, Congress provided a number of constraints and guardrails, including a requirement to provide 60-day advance notice to the EPA prior to commencing a citizen suit and a venue provision specifying that citizen suits may only be brought in federal district court.[113] By nature of being brought in Federal district court, such matters are subject to generally applicable evidentiary rules and standards for adjudicating such allegations. None of these provisions contemplate endowing particular entities with the status of certified monitors for purposes of ensuring compliance, as the Super Emitter Program does. The EPA proposes that the CAA's provisions for citizen involvement in enforcement are the appropriate avenue for citizen participation in such matters. The EPA now believes that third-party certification could have an unintended influence on enforcement actions, including with respect to a district court's review of a citizen action brought by a certified third-party. That is, the EPA is concerned that status as a certified third-party could inaccurately and improperly suggest that a citizen action has been endorsed by the Agency, implicitly or otherwise. In this way, the Super Emitter Program risks empowering unaffiliated third parties to exercise an enhanced enforcement role that the EPA did not intend to establish in finalizing the Super Emitter Program and appears to lack a statutory basis.

The same reasoning explained above extends to all regulations where the EPA included provisions from the Super Emitter Program, such as provisions at 40 CFR 60.5371, 40 CFR 60.5371a, 40 CFR 60.5371b, and 40 CFR 60.5388c.

Accordingly, for the reasons described above, the EPA proposes to repeal the Super Emitter Program. The Super Emitter Program includes requirements under NSPS OOOO, OOOOa, OOOOb and EG OOOOc. As such, the EPA specifically proposes to remove the Super Emitter Program provisions at 40 CFR 60.5371, 40 CFR 60.5371a, 40 CFR 60.5371b, and 40 CFR 60.5388c. The EPA also proposes to remove references to

[113] *See* 42 U.S.C. 7604(a)(1), (b), (c).

these provisions at 40 CFR 60.5398b(d), and 60.5420b(b)(14); and 40 CFR 60.5420c(b)(14); and in the definition of "[a]verage aggregate detection threshold" in 40 CFR 60.5430b and 40 CFR 60.5430c. Lastly, the EPA proposes to remove reference to the Super Emitter Program in table 1 to subpart OOOOc of 40 CFR part 60. The EPA solicits comment on this proposal (Question III.1a), including any comments related to the policy merits of the Super Emitter Program and to the EPA's legal bases for the Super Emitter Program.

B. Liquids Unloading

1. Background

Under the March 2024 Final Rule, both the NSPS OOOOb and EG OOOOc require each affected and designated gas well facility that unloads liquids to employ techniques (*e.g.*, manual unloading steps taken to unload liquids) or technology(ies) (*e.g.*, plunger lift systems, surface jet pumps, velocity strings) that minimize or eliminate venting of emissions during liquids unloading events. As an alternative, owners or operators may comply with the GHG and VOC standards by routing vented emissions to a control device that reduces methane and VOC emissions (methane only for designated facilities) from each gas well liquids unloading event by 95.0 percent.

For unloading technologies or techniques that could result in venting to the atmosphere, the March 2024 Final Rule requires owners or operators to follow certain work practices. The March 2024 Final Rule requires that owners or operators employ and document best management practices to minimize venting of methane and VOC emissions for each gas well liquids unloading operation. Specifically, owners or operators of affected and designated gas well facilities that undergo liquids unloading events must develop, maintain, and follow a best management practice plan to minimize venting of methane and VOC emissions (methane only for designated facilities) to the maximum extent possible from each gas well liquids unloading operation. This best management

practice plan must meet the following minimum criteria: (1) include steps that create a differential pressure to minimize the need to vent a well to unload liquids; (2) include steps to reduce wellbore pressure as much as possible prior to opening the well to the atmosphere; (3) unload liquids through the separator where feasible; and (4) close all wellhead vents to the atmosphere and return the well to production as soon as practicable. The standards are the same for the NSPS and the EG.

Where liquids unloading events are conducted using a technology or technique that eliminates venting to the atmosphere, the March 2024 Final Rule requires owners and operators to report the identification of the well along with the non-venting technology or technique used in their annual report. If more than one non-venting method is used, the March 2024 Final Rule requires that owners and operators maintain records of all the differing non-venting liquids unloading methods used at the well affected/designated facility.

When unplanned venting occurs from these wells during a compliance period, an owner or operator is required to follow their best management practices plan for such events and comply with the associated recordkeeping and reporting requirements for those events. The March 2024 Final Rule requires owners and operators to maintain records for the number of unplanned events where emissions are vented to the atmosphere during a liquids unloading operation. The March 2024 Final Rule requires owners and operators to provide the above recordkeeping information to the EPA in their annual report.

2. Additional Background and Summary of Proposed Changes and Rationale

Petitioners raised two issues for reconsideration on the March 2024 Final Rule liquids unloading requirements.[114, 115] First, petitioners disagreed with the EPA's promulgated reporting and recordkeeping requirements for liquids unloading events for non-emitting equipment or activities. Second, petitioners argued that the alternative compliance option for GHG and VOC reduction standards - allowing an owner or operator to route emissions to a control device via a CVS - imposes inappropriate ongoing compliance assurance requirements when applied to normally intermittent liquids unloading activities. Sections III.B.2.a and III.B.2.b of this preamble provide additional background, a summary of proposed changes, and rationale for proposed changes for both of these issues.

a. Recordkeeping and Reporting Requirements for Non-Emitting Operations

Background. Petitioners asserted that the presence of emissions is inherent in the definition of standard of performance and that a source without emissions cannot be subject to such a standard of performance.[116] Petitioners also stated that the EPA itself recognized its inability to regulate these non-venting events when it "streamlined recordkeeping and reporting requirements" based on concerns raised during the comment period for the March 2024 Final Rule.[117] Specifically, the petitioner quoted the EPA's Response to Comments for the March 2024 Final Rule as stating that the Agency agreed that "requiring an owner or operator to comply with some of the proposed recordkeeping and reporting requirements in instances where an unloading event does not result in venting to the atmosphere would impose a burden without any added benefit

---

[114] API & AXPC (2024a). Re: Provisions in EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review." Creating Immediate Compliance and Implementation Issues. April 5, 2024.
[115] API & AXPC (2024b). Re: Request for Administrative Reconsideration of EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review" May 6, 2024. pgs. 33-34.
[116] API & AXPC (2024b). Re: Request for Administrative Reconsideration of EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review" May 6, 2024. pgs. 33-34.
[117] 89 FR 16956 (March 8, 2024).

environmentally . . ."[118] Petitioners argued that based on these reasons, the EPA should remove all recordkeeping and reporting requirements associated with non-venting activities and equipment.

Summary of Proposed Changes and Rationale. In promulgating the March 2024 Final Rule, the EPA considered commenters' concerns and the examples provided regarding the burden associated with the liquids unloading operations' recordkeeping and reporting requirements proposed in 2022. In the March 2024 Final Rule, the EPA streamlined recordkeeping and reporting requirements in some instances where an unloading event does not result in venting to the atmosphere and where such requirements would impose a burden without providing any environmental benefit (*e.g.*, requiring operators to track and report the number of liquids unloading events that occurred when implementing a non-venting liquids unloading technology or technique). Where liquids unloading events are conducted using a technology/technique that eliminates venting to the atmosphere, the March 2024 Final Rule requires owners and operators to report the identification of the well along with the non-venting technology or technique used in their annual report, while continuing to comply with the applicable recordkeeping requirements for those events. Where unplanned venting occurs from these wells during a compliance period, an owner or operator is required to follow their best management practices plan for such events and comply with the associated recordkeeping and reporting requirements for those events.

The EPA proposes to further eliminate the reporting requirements for non-venting liquids unloading well site events, while maintaining the recordkeeping requirements for these events in both the NSPS OOOOb and EG OOOOc due to the continued possibility

[118] U.S. EPA. (2023b). Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule. *See* Response I-12-33.

of an unplanned venting event. The EPA proposes changes to 40 CFR 60.5376b(a)(1) and 60.5420b(c)(2)(i) of NSPS OOOOb, and 40 CFR 60.5390c(a)(1) and 60.5420c(c)(1)(i) of EG OOOOc. Specifically, the EPA proposes that the NSPS OOOOb and EG OOOOc continue to require that owners and operators maintain records of the identification of each well (*i.e*., U.S. Well ID or U.S. Well ID associated with the well affected facility) that conducts a gas well liquids unloading operation during the reporting period without venting of methane and/or VOC emissions and the non-venting gas well liquids unloading method used. These records, which EPA understands would already be retained as part of normal site operations records/documentation, do not constitute a burdensome requirement. The EPA solicits comment on this proposal. (Question III.2a)

The EPA is also soliciting comment on repealing part or all of the recordkeeping and reporting requirements for liquids unloading in NSPS OOOOb, and the corresponding presumptive requirements in EG OOOOc. The Agency's ICR associated with the March 2024 Final Rule anticipated that the recordkeeping and reporting burdens associated with liquids unloading would increase significantly over the first three years of implementation. The EPA seeks comment on whether those projected costs have materialized, and if so, which provisions are the most burdensome and whether the costs may warrant further revisions in relation to the purposes of the requirements. (Question III.2b)

b. Control Device Compliance Requirements

Background. Petitioners stated that while they generally support the work practice procedures finalized in 40 CFR 60.5376b, they do not support the covers, closed vent and control device compliance assurance requirements at 40 CFR 60.5376b(g), which are associated with the alternative compliance option of routing vented emissions to a control device.[119] While the petitioners do not oppose including the alternative compliance

[119] API & AXPC. (2024a).

option, they assert that the associated ongoing compliance assurance requirements are inappropriate. They explain that, when implementing the work practice procedures to reduce emissions from well liquid unloading activities as specified in 40 CFR 60.5376b(b) through (f), operators will review the characteristics of the well at the time of the event. If certain conditions (*e.g.*, operator safety, equipment malfunctions) are present, an operator may need to deviate from a planned option for minimizing emissions and instead route gas to a temporary flare to minimize emissions and further reduce the amount of gas that would be vented by 95.0 percent. Petitioners noted that, given the short-term nature of liquids unloading events, the ongoing compliance assurance related to both a CVS and control device would be inappropriate since many of the activities would be forced to occur when liquids unloading activities are not even occurring (*e.g.*, CVS inspections). They contended that it would also be untenable to schedule and manage these activities during unloading events given their variable and short duration. Petitioners recommended that the EPA authorize the use of a temporary flare or portable control device to handle emissions from liquids unloading. Specifically, they suggested that, due to the temporary nature of these activities, the control device compliance requirements should mimic those utilized for well completions affected facilities, *i.e.*, a requirement to operate with a reliable continuous pilot flame during the liquid unloading activity. Petitioners noted that a temporary control device is typically used when the permanent control device is down for maintenance (*e.g.*, during a gas plant turnaround) or to reduce emissions from intermittent activities (*e.g.*, liquids unloading where feasible). In general, the petitioners stated that the March 2024 Final Rule does not specifically address temporary control devices, and as such, temporary control devices would presumably have to meet what they argue are untenable monitoring and performance testing requirements required under the rule for these control devices. Therefore, the petitioners urged the EPA to revise the March 2024 Final Rule to clearly exempt

temporary control devices from the monitoring and performance testing requirements required under the rule for these control devices.

Summary of Proposed Changes and Rationale. For liquids unloading operations, the initial and supplemental proposals for the March 2024 Final Rule did not include an option to route emissions to a flare/control device. The March 2024 Final Rule introduced an additional means of complying with the GHG and VOC standards by reducing methane and VOC emissions from each gas well liquids unloading event by 95.0 percent by routing emissions to a control device via a CVS. This option was added in response to comments requesting that routing to a control device be allowed, noting that the emissions reduction that would be achieved could be greater than or equal to those achieved through the implementation of best management practices (BMPs). The EPA acknowledges the practical implications of requiring the same control device compliance assurance requirements that were developed for control devices where emissions are routed to a permanent control device to also apply where emissions are routed to a temporary control device. For the same reasons specified by the petitioners, the EPA proposes to determine that it is warranted to develop different control device and compliance provisions that acknowledge the differences between permanent and temporary control devices. As such, the EPA proposes to allow routing of vented gas to a temporary control device during liquids unloading operations with streamlined compliance assurance requirements. *See* section III.H.1.e (Temporary Control Devices and Backup Control Devices) of this preamble for a detailed discussion on the EPA's proposed compliance provisions for temporary control devices for use during intermittent liquids unloading events.

C. Process Controllers

1. Background

Under the March 2024 Final Rule, the NSPS OOOOb final standards and EG OOOOc final presumptive standards contain requirements for each process controller affected or designated facility. These rules define process controller affected and designated facilities as the collection of natural gas-driven process controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. The definitions of affected and designated facilities exclude natural gas-driven process controllers that function exclusively as emergency shutdown devices as well as process controllers not driven by natural gas, so neither the NSPS nor the EG applies to these types of controllers. The NSPS standards and the EG presumptive standards require process controller affected or designated facilities to have zero methane and VOC emissions to the atmosphere, except for affected or designated process controllers located in Alaska at a site without electrical power. For process controller affected or designated facilities located at Alaska sites that do not have access to electrical power, an owner or operator may either route process controller emissions through a CVS to a control device that reduces emissions by 95.0 percent, or they may use intermittent vent or low-bleed process controllers (*i.e.,* those that have a bleed rate less than or equal to 6 standard cubic feet per hour (scfh)) so long as they perform periodic monitoring of their intermittent controllers to ensure those controllers are not emitting to the atmosphere during idle periods.

To address concerns about new sources' ability to obtain the equipment necessary to demonstrate compliance with the final standard of zero emissions immediately upon the effective date of the final rule, the March 2024 Final Rule NSPS allowed up to 1 year from the effective date of the final rule (*i.e.*, May 7, 2025) to come into full compliance with the final NSPS standard of zero emissions. Until that date of compliance, owners and operators must demonstrate compliance with an interim standard which mirrored the

requirements for sites in Alaska that do not have access to electrical power.[120] To address continuing concerns about the supply chain and the ability of new sources to obtain the necessary equipment to comply with the process controller requirements by May 7, 2025, the EPA issued an IFR and request for comment on July 31, 2025 to revise the compliance date for the zero emissions standards.[121] The EPA then responded to comments on the IFR and issued a final rule.[122] The NSPS compliance date for the zero emissions standard for process controllers is now January 22, 2027, and the interim standard continues to apply to process controller affected facilities (*i.e.*, the same standard applicable to sites in Alaska without access to electricity) until that date.[123]

For EG OOOOc, which included presumptive standards for process controllers, the March 2024 Final Rule included a State plan submittal deadline of 24 months after publication of the final EG OOOOc (*i.e.*, March 9, 2026). To provide more time for States to develop their State plans, the July 2025 IFR extended the State plan submittal deadline to January 22, 2027. *See* section II.E of this preamble for additional details regarding the IFR.

Reconsideration petitioners raised several issues regarding the March 2024 Final Rule process controller requirements that they requested the EPA reconsider. One issue regards cost effectiveness of the presumptive standard for some applications, with petitioners asserting that the zero emissions standard is not cost effective for existing process controllers used in high-pressure systems at transmission and storage compressor stations. Another issue regards the definition of modification for process controllers, for which petitioners assert that the EPA should clarify that a modification of affected or designated process controller facilities only occurs when there is both an increase in

---

[120] 89 FR 16929, 16930 (March 8, 2024).
[121] 90 FR 35966 (July 31, 2025).
[122] The December 2025 Final Rule responded to the comments and reaffirmed the conclusions and the regulatory amendments made in the July 2025 IFR. 90 FR 55671 (December 3, 2025).
[123] 90 FR 35973, 35974 (July 31, 2025).

emissions and one or more process controllers is added to the affected or designated facility. Sections III.C.2.a and III.C.2.b of this preamble provide additional background, a summary of proposed changes, and the rationale for the proposed changes. Petitioners also raised issues regarding process controllers at marginal well sites and process controllers on temporary equipment. Finally, petitioners also raised concerns regarding reporting burdens centered around process controller monitoring and recordkeeping. Sections III.K.1.f and III.H.1.e of this preamble address these issues.

2. Additional Background and Summary of Proposed Changes and Rationale

a. Process controllers on high-pressure systems at transmission and storage compressor stations

Background. Petitioners provided information regarding the cost of process controllers used in high-pressure systems at transmission compressor stations, which shows that the retrofit cost for existing facilities to come into compliance with the zero-emissions process controller standard for high-pressure systems is over 400 times higher than that analyzed by the EPA for the March 2024 Final Rule. [124] EPA estimated a single-pollutant cost effectiveness value of $1,924/ton of methane for retrofitting an existing facility with compressed air in the Small Transmission and Storage Model Plant analysis in the March 2024 Final Rule.[125] For comparison, three companies estimated a cost effectiveness of $860,714, $2,887,686, and $3,417,977 per ton of methane reduced, respectively, to replace valve actuators at existing high pressure transmission and storage stations they were operating.[126] Petitioners explained that the amount of compressed air

---

[124] Interstate Natural Gas Association of America (INGAA). (2024a). Petition. Letter to Michael S. Regan from INGAA. Re: Petition for Reconsideration of Final Rule or, in the Alternative, for New Rulemaking in "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: for Reconsideration. (Non-Confidential Version). May 15, 2024.

[125] 89 FR 16820 (March 8, 2024).

[126] Interstate Natural Gas Association of America (INGAA). (2024a). Petition. Letter to Michael S. Regan from INGAA. Re: Petition for Reconsideration of Final Rule or, in the Alternative, for New Rulemaking in "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: for Reconsideration. (Non-Confidential Version). May 15, 2024.

needed to actuate high-pressure process controllers, which the petitioners characterized as requiring a pressure of 100 pounds per square inch gauge (psig) or greater, requires more expensive process controller equipment and facility infrastructure than that included in the EPA's BSER analysis for the March 2024 Final Rule. Petitioners noted that the EPA's analysis focused on upstream processes, data, and equipment, and these elements are not the same for many process controller applications in the transmission and storage segment. Petitioners asserted that the replacement of the process controllers, and in particular, the valve actuators that would be required to meet the zero emissions standard for these high-pressure applications is much more expensive than that included in the EPA's analysis for the cost of replacing process controllers. Petitioners also stated that due to reliability and safety concerns, the conversion of these process controllers and their actuators would be to instrument air-powered devices rather than electrically-powered or self-contained devices. Petitioners noted that this is because pneumatic actuators are typically faster than electric alternatives, which is essential for quick process adjustments at the compressor.

Petitioners provided data from three companies estimating the cost effectiveness of replacing natural gas-powered process controllers and actuators with compressed air-powered process controllers and actuators at facilities that have electricity at the site. These values ranged from $860,714 to $3,417,977 per ton of methane emissions reduced, which are 440 and 1,750 times higher than the EPA's estimate for the March 2024 Final Rule of $1,951 per ton of methane reduced from large transmission and storage facilities that have electricity at the site.[127] Based on these estimates, petitioners argue it is not cost effective to replace existing natural gas-powered process controllers and actuators in these high pressure applications with compressed air-powered process controllers and actuators.

[127] INGAA (2024a).

Summary of Proposed Changes and Rationale. The EPA proposes to amend the standards for modified and reconstructed facilities under NSPS OOOOb and the presumptive standards in the EG OOOOc model rule for process controllers at compressor stations, as defined in 40 CFR 60.5430b and 40 CFR 60.5430c that require an actuation pressure greater than 100 psig. Like other process controllers, natural gas-driven process controllers at natural gas compressor stations that require an actuation pressure greater than 100 psig and that function exclusively as emergency shutdown devices are not included in the affected or designated facility. This is also true for controllers not driven by natural gas. Put another way, the revisions that the EPA is proposing here do not impact the regulatory exclusion for emergency shutdown devices and for controllers not driven by natural gas. The EPA proposes to create a new subcategory which includes new NSPS requirements (for modified and reconstructed sources), and new presumptive standards, for these high-pressure process controllers, which are based on the revised BSER analysis and on the conclusion that retrofitting to zero-emissions controllers is not technically feasible or cost effective. Under the proposed requirements, an owner or operator may either route process controller emissions through a CVS to a control device that reduces emissions by 95.0 percent, or they may use low-bleed natural gas-powered process controllers (*i.e.*, those that have a natural gas bleed rate less than or equal to 6 scfh) in combination with intermittent vent process controllers so long as the owner/operator periodically monitors the intermittent controllers to ensure they are not emitting to the atmosphere during idle periods.

The EPA considered the petitioners' concerns and the information provided regarding the costs and emission reductions associated with the process controller requirements at facilities with process controllers that are on high-pressure systems at transmission compressor stations. The EPA evaluated the data provided by the petitioners and contacted vendors regarding the costs of process controllers and actuators for high-

pressure systems at these sites. The EPA agrees that the equipment costs are higher than those considered in the 2024 BSER analysis, as the Agency did not have sufficient information available at that time to anticipate the need for different process controller equipment for high-pressure systems at transmission compressor stations. The EPA revised the analysis performed for the March 2024 Final Rule on cost effectiveness of zero-emitting process controllers for existing, modified and reconstructed sources to include the new information for process controllers on high pressure systems at transmission compressor stations.[128] The nature of these high pressure systems limits the technical feasibility of routing emissions from these controllers to a process, control, or sales line and also limits the use of self-contained process controllers. These facilities need to use fast-acting process controllers and actuators. Electric process controllers are not fast enough. Controllers driven by compressed air are fast enough; they are technically feasible, but their costs are very high. The EPA evaluated the costs and emissions reductions of replacing natural gas-powered process controllers with process controllers driven by compressed air. The EPA estimates that to replace natural gas-driven process controllers on high pressure systems with process controllers driven by compressed air at compressor stations, the capital costs would be $2.4 million, annualized capital costs would be $263,300, and emissions would be reduced by 0.2 tons per year (tpy) of VOC and 8.0 tpy of methane, resulting in a cost of $10.9 million per ton of VOC emissions reduced and $33,100 per ton of methane emissions reduced.[129] The EPA proposes to determine that these updated values are not cost effective. Based on this determination, along with the knowledge that only this subset of controllers faces these higher equipment and operating costs, the EPA proposes to determine that a different

---

[128] Technical Memorandum to Docket ID EPA-HQ-OAR-2021-0317. *Revised Analysis for Process Controllers and Pumps for Reconsideration of New Source Performance Standards 40 CFR 60, Subpart OOOOb and Emissions Guidelines 40 CFR 60, Subpart OOOOc*. August 28, 2026.

[129] This and additional information regarding the revised analysis conducted for process controllers may be found in the TSD for this proposal, which is available in the docket for this action.

standard (and presumptive standard) for process controllers on high pressure systems would be warranted (a standard other than the zero emission standard) and evaluated other emissions control options. These options are explained below.

The EPA evaluated the use of alternative control options to zero-emitting process controllers in NSPS OOOOb and EG OOOOc. The only emissions control option identified as technologically feasible and cost effective was the requirement in the NSPS OOOOb and EG OOOOc for sites in Alaska that do not have access to electrical power. To evaluate the costs of this option for process controllers on high-pressure systems at transmission compressor stations, the EPA assumed that sites would choose to use low-bleed or intermittent. Consistent with the distribution of controller types documented in the March 2024 Final Rule, where the Agency determined that intermittent-vent controllers represent the predominant controller type in the field (as reflected in the one-to-three ratio of low bleed to intermittent vent used in the model plant analysis), it was assumed that all controllers were of the intermittent type, and that the process controllers would be monitored quarterly with OGI to ensure they are operating properly.[130] The EPA estimates that annual costs associated with this option would be $300, and emissions would be reduced by 0.15 tpy of VOC and 5.4 tpy of methane, resulting in a cost of $2,000 per ton of VOC emissions reduced and $55 per ton of methane emissions reduced from a representative affected facility (*i.e.*, transmission compressor station). The EPA proposes to determine that these values are cost effective and proposes these requirements (and this presumptive standard) for process controllers on high pressure systems at compressor stations for modified and reconstructed facilities under NSPS OOOOb and for the presumptive standards in the EG OOOOc model rule. The EPA solicits comment on this proposal. (Question III.3a)

[130] 89 FR 16924.

Based on the information provided by petitioners, it is the EPA's understanding that only the retrofit costs for existing sources to come into compliance with a zero emissions standard are prohibitive. It is the EPA's understanding that when new facilities are being planned and constructed, it is possible for zero emissions process controllers to be incorporated into the facility design at a cost that is similar to the cost of including natural gas-driven process controllers, such that it is cost effective to include zero-emissions process controllers on high pressure systems at natural gas compressor stations. However, if these facilities were built with process controllers that use natural gas and are then required to replace those process controllers with zero emitting equipment, essentially doubling the cost of this already expensive equipment, it could be cost prohibitive and therefore unreasonable considering the relatively small amount of emissions reduction that would be achieved.

Accordingly, the EPA is proposing a different standard only for existing sources that would be required to retrofit equipment to comply with the NSPS OOOOb standards (*i.e.*, modified and reconstructed facilities) and the EG OOOOc presumptive standards but is not proposing an alternative or different standard for newly constructed facilities (*i.e.*, for sources subject to NSPS OOOOb that were not previously existing sources that then modified or reconstructed). Based on the above understanding, the EPA does not believe that this proposed change would allow, or result in, new facilities that are planned and constructed with zero emissions process controllers to revert to natural-gas driven process controllers. As a function of permitting and cost, the Agency does not believe that new facilities designed with zero emissions process controllers would have the incentive or ability to make such a change by modifying or retrofitting, nor is that result intended by this proposed change. The EPA is soliciting comment on this aspect of the proposal, including whether additional or alternative standards or subcategories for

sources subject to NSPS OOOOb are merited and whether the EPA's premise regarding cost equivalency in the design and initial planning phases is accurate. (Question III.3b)

The EPA is also soliciting comment on the actuation pressure which best categorizes these high-pressure systems and whether additional subcategories are merited. Industry representatives have suggested using 100 psig as a general guideline for the level of pressure at which different types of process controllers, and actuators in particular, become more costly than the equipment needed for lower pressure levels. However, the EPA is interested in any information that may suggest that another or additional pressure levels would be better suited to delineate the subcategory or further subcategories. (Question III.3c)

b. Modification criteria for process controllers

Background. Petitioners requested that the EPA clarify that a modification for process controllers occurs only when there is both an increase in emissions and one or more controllers are added to the facility. Petitioners recounted that the EPA changed the definition of affected facility for process controllers from a single process controller to the collection of all the process controllers at a well site in NSPS OOOOb. Petitioners also recounted that in NSPS OOOOb, the EPA changed the modification criteria to state, "[f]or the purposes of § 60.5390b, in addition to the definition in § 60.14, a modification occurs when the number of natural gas-driven process controllers in the affected facility is increased by one or more." According to the petitioners, the regulatory language seems to indicate that process controllers would be considered modified only if there is an increase in emissions and the number of natural gas-driven process controllers is increased by one or more, but in the March 2024 Final Rule preamble, the EPA focused only on the number of increased controllers, implying that an increase in process controllers automatically increases emissions from the affected facility. According to the petitioners, there are many actions that can take place at the time a new controller is

added to offset its emissions, such as when a new controller replaces an existing controller with the same or with higher emissions or when new controller emissions are offset by the removal of other controllers or adjustments in their operations. The petitioner reported that these concepts have long been a part of facility operations management to limit the need for additional permitting.

Summary of Comment Solicitation. The EPA acknowledges the petitioners' request for clarification and is soliciting comment on whether revisions to the current modification determination language in 40 CFR 60.5365b(d)(1) for process controllers are warranted. The EPA maintains that increasing the total number of natural gas-driven process controllers at a facility generally increases the emissions of natural gas, methane, and VOC to the atmosphere by the nature of the equipment, which bleeds gas continuously and/or emits gas during actuation events, emits gas during malfunctions of the equipment, or emits gas through leaks in the equipment or from connections to CVSs. Adding one more natural gas-emitting process controller to an existing set of natural gas-emitting process controllers is therefore generally expected to result in increased emissions. The intent and purpose of this provision was to simplify modification determinations by eliminating the need for owners/operators to determine emissions before and after a change in a process controller affected facility and to reduce the burden on permitting authorities reviewing that modification determination. That said, the EPA also recognizes that by statute, an increase in emissions is a necessary condition to a modification determination. The EPA also notes that the number of process controllers in the affected facility does not increase when a new natural gas-driven process controller replaces an existing one, or when the addition of a process controller is offset by the removal of one or more existing process controllers. The petitioner suggests that, in some cases, operational adjustments to other controllers could offset the emissions of the new controller. The EPA is soliciting additional information on the relative change in

emissions when these process controller replacement events occur and the frequency with which they occur. The EPA also requests comment on whether the existing modification determination language appropriately captures changes resulting in emissions increases, or whether adjustments to the current criteria are needed to reflect industry practices, such as clarifying what constitutes net increases in emissions from the source. (Question III.3d)

The EPA recognizes that other issues raised in reconsideration petitions[131] on the March 2024 Final Rule related to process controllers affected and designated facilities are of interest to stakeholders. The EPA is still evaluating some of those other issues. One of those issues, for example, suggests that the EPA reevaluate the cost-effectiveness of process controllers, especially for existing source retrofits and consider alternative options for compliance. Petitioners specifically suggest that the EPA consider for both NSPS OOOOb and EG OOOOc that routing emissions from process controllers to a control device should be allowed as an option for compliance. Furthermore, petitioners suggest that the EPA consider further subcategorization for existing sites that do not have access to electricity or have a de minimis number of process controllers.

The EPA is soliciting comment from stakeholders and the public on these and other specific issues related to process controller affected and designated facilities. Specifically, the EPA solicits comment on whether it would be appropriate to consider broader flexibility for process controllers as the petitioners suggest. The EPA asks for additional information and data related to cost and technical feasibility of retrofits, routing to new or existing control devices, and challenges related to electricity access. The EPA also requests comment on recordkeeping, retention, and reporting requirements related to process controllers and whether it is appropriate to repeal the zero emission

[131] API (2025). Re: Request for Administrative Reconsideration of EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities" - NSPS OOOObc. September 12, 2025.

standard for process controllers under NSPS OOOOb and EG OOOOc based on information suggesting that the Agency's prior cost and emission-reduction projections were erroneous as relevant to the BSER determinations and resulting standards for such requirements. (Question III.3e)

D. Pumps

1. Background

Under the March 2024 Final Rule, the NSPS OOOOb final standards and EG OOOOc final presumptive standards contain requirements for each pump affected or designated facility, which is the collection of natural gas-driven pumps at a well site, centralized production facility, onshore natural gas processing plant, or compressor station. Pumps that are in operation less than 90 days per calendar year or that are not natural gas-driven are not included in the definition of affected or designated facility. For pump affected or designated facilities located at a site that has access to electrical power and for those without access to electrical power that have three or more natural gas-driven diaphragm pumps, the pump affected facility must have zero methane and VOC emissions to the atmosphere. For each pump affected or designated facility located at a site that does not have access to electrical power and that also has fewer than three natural gas-driven diaphragm pumps, emissions must be controlled if a control device is otherwise onsite.

Section III.D.2 of this preamble provides additional background, summary of proposed changes, and rationale for proposed changes.

2. Additional Background and Summary of Proposed Changes and Rationale

Background. Petitioners asserted that the EPA failed to justify NSPS OOOOb standards and EG OOOOc presumptive standards of zero emissions for existing natural gas-driven pumps that are already in compliance with NSPS OOOOa, which requires certain natural gas-driven diaphragm pumps to be routed to a control device or process

that achieves an emissions reduction of at least 95.0 percent.[132] Petitioners requested that the EPA's model rule and presumptive standards in EG OOOOc and the standards in OOOOb (for modified and reconstructed facilities) allow these existing pumps that are already reducing emissions by 95 percent to continue to comply with NSPS OOOOa instead of having to convert to the zero emissions standard (100 percent control as opposed to 95 percent control). Petitioners implied that the EPA did not adequately consider the incremental cost effectiveness of requiring existing diaphragm pumps subject to NSPS OOOOa (and already achieving 95 percent control) to achieve zero emissions.

Summary of Proposed Changes and Rationale. The EPA proposes to amend the standards for modified and reconstructed sources under NSPS OOOOb and the presumptive standards in the EG OOOOc model rule for pumps. The proposed amendments include an alternative emissions standard of 95.0 percent control for individual pumps within a pump designated (or affected) facility that were already routing emissions through a CVS to a control device achieving 95.0 percent or greater control of emissions on the effective date of the March 2024 Final Rule (*i.e.*, December 6, 2022). These pumps that are already reducing their emissions by at least 95 percent would not be required to achieve zero emissions (100 percent reduction of emissions), where zero-emitting pumps would be the otherwise applicable standard (*i.e.*, sites with access to electricity or sites without access to electricity that have three or more diaphragm pumps). The modified/reconstructed standards under NSPS OOOOb and the presumptive standards under EG OOOOc for any other pumps in the pump designated facility (meaning those whose emissions were not already reduced by 95.0 percent) would remain those finalized in the March 2024 Final Rule. This proposed alternative standard would apply to any pumps at an affected pump facility or designated facility that

[132] API-AXPC (2024b).

were already routing emissions through a CVS to a control device achieving 95.0 percent or greater control of emissions on the effective date of the March 2024 Final Rule, regardless of whether or not those pumps were previously required by NSPS OOOOa to achieve 95.0 percent emissions reductions.

The EPA considered the petitioner's concerns and evaluated the incremental cost effectiveness of moving from 95.0 percent emissions control to zero emissions (*i.e.*, 100 percent emissions control). For sites that have access to power from the electrical grid, the options for achieving zero emissions that were included in this analysis were the use of a compressed air system to power existing pneumatic pumps and the replacement of existing natural gas-powered pneumatic pumps with electrical pumps. For sites that do not have access to power from the electrical grid, the analysis included the option to replace existing natural gas-powered pneumatic pumps with electrical pumps powered by on-site solar panels. These options were the most cost effective means of achieving zero emissions that were analyzed for the March 2024 Final Rule. In the analysis, the EPA evaluated the difference in costs and the difference in emissions between the 95.0 percent emissions control scenario and the 100 percent emissions control scenario. As the systems required for 95.0 percent emissions control already exist and operate, and there is no overlap in equipment used between these systems and the systems that would be used for the zero emissions options analyzed, the EPA assumed that the difference in costs equate to the full costs of the zero emissions system. The difference in emissions would be 5 percent of the total emissions (*i.e.*, the difference between 95.0 percent and 100 percent control). A summary of the results of this analysis is shown in table 3. The cost effectiveness values shown in table 3 are based on the estimated total annual costs of each zero-emissions pump option and the emissions reductions associated with going from 95.0 percent to 100 percent emissions control. Further information regarding the

analysis conducted for pumps may be found in a technical memorandum, available in the docket for this proposed rule.[133]

Table 3. Summary of Cost effectiveness Analysis of Pump Incremental Emissions Reductions

Location type and number of pumps at site	Incremental Cost effectiveness ($/tpy)	
	VOC	Methane
Electric pumps (grid powered) - production segment:		
One diaphragm	$33,049	$9,188
Two diaphragm	$33,049	$9,188
Three diaphragm	$33,049	$9,188
Four diaphragm	$33,049	$9,188
Electric pumps (grid powered) - transmission and storage segment:		
One diaphragm	$253,902	$7,033
Two diaphragm	$253,902	$7,033
Three diaphragm	$253,902	$7,033
Four diaphragm	$253,902	$7,033
Electric pumps (solar powered) - production segment:		
One diaphragm	$37,388	$10,394
Two diaphragm	$37,388	$10,394
Three diaphragm	$37,388	$10,394
Four diaphragm	$37,388	$10,394
Electric pumps (solar powered) - transmission and storage segment:		
One diaphragm	$287,234	$7,956
Two diaphragm	$287,234	$7,956
Three diaphragm	$287,234	$7,956
Four diaphragm	$287,234	$7,956
Compressed air-driven pumps - production segment:		
One diaphragm	$327,556	$91,061
Two diaphragm	$163,778	$45,530
Three diaphragm	$109,185	$30,354
Four diaphragm	$81,889	$22,765
Compressed air-driven pumps - transmission and storage segment:		
One diaphragm	$2,516,449	$69,699
Two diaphragm	$1,258,224	$34,850
Three diaphragm	$838,816	$23,233
Four diaphragm	$629,112	$17,425

[133] Technical Memorandum to Docket ID EPA-HQ-OAR-2021-0317. *Revised Analysis for Process Controllers and Pumps for Reconsideration of New Source Performance Standards 40 CFR 60, Subpart OOOOb and Emissions Guidelines 40 CFR 60, Subpart OOOOc*. August 28, 2026.

As seen in table 3, the estimated incremental cost effectiveness to achieve 100 percent emissions control for both VOC and methane are above the values considered to be reasonable by the EPA. Specifically, the lowest cost effectiveness values of all these options for emissions reductions are estimated to be $7,033 per ton of methane reduced and $33,049 per ton of VOC reduced. Both of these values are above what the EPA has historically considered to be cost reasonable when determining the BSER for VOCs and methane under CAA section 111.[134] As there is no cost effective control option that can achieve the incremental emissions reductions from 95.0 percent to 100 percent reduction, the EPA proposes to determine that the NSPS standard for modified and reconstructed sources and the EG presumptive standard should allow owners and operators of sources with pumps already controlled by 95.0 percent to continue to use and maintain those controls rather than undertake costly capital improvement projects to switch to emissions controls that result in only 5 more percentage points emissions reductions than achieved with the use of the controlled pumps. Therefore, the EPA proposes to include an alternative standard for modified and reconstructed facilities under NSPS OOOOb and the presumptive standards in EG OOOOc to take into account the updated BSER analysis that properly considers the incremental costs of converting to zero emissions for individual pumps within a designed pump facility that are routed through a CVS to a control device achieving 95.0 percent or greater control of emissions. This alternative standard would require these pumps to achieve 95.0 percent or greater control of emissions as well as meet the compliance requirements for CVSs and control devices in NSPS OOOOb and EG OOOOc.

---

[134] Cost reasonableness for BSER purposes under CAA section 111 is generally discussed in the March 2024 Final Rule, 89 FR 16864, although the values expressed in that rule would now be higher based on 2024 dollars. By way of example, the EPA determined in that 2024 rulemaking that cost effectiveness values of up to $5,540/ton of VOC reduction were reasonable at that time. By way of another example, EPA noted in the November 2021 Proposal that the EPA previously determined that methane cost effectiveness values in the 2016 NSPS OOOOa of $2,185/ton of methane reduction represented reasonable costs.

While the petitioner specifically requested this emissions control level for pumps that were required to reduce emissions by 95.0 percent under NSPS OOOOa, the EPA is proposing to determine that this alternative standard should also be available to other pumps that had emissions controlled by 95.0 percent on or before December 6, 2022. There is no difference in the incremental cost effectiveness of going from 95.0 percent to 100 percent emissions control between those pumps achieving 95.0 percent control due to NSPS OOOOa requirements and those that were achieving 95.0 percent emissions control for other reasons, such as State or local requirements. Therefore, the EPA proposes to include this alternative standard for all such existing pumps in NSPS OOOOb (for modified or reconstructed sources) and EG OOOOc.

E. Fugitive Emissions

1. Background

Under the March 2024 Final Rule, NSPS OOOOb includes standards for fugitive emissions components affected facilities and EG OOOOc includes presumptive standards for fugitive emissions components designated facilities. As described in the preamble to the March 2024 Final Rule, each fugitive emissions components affected facility and each fugitive emissions components designated facility includes the collection of fugitive emissions components at a well site, centralized production facility, or a compressor station.[135] As defined at 40 CFR 60.5430b and 60.5430c, fugitive emissions include an indication of emissions observed from a fugitive emissions component using audible, visual, and olfactory (AVO), an indication of visible emissions observed from a fugitive emissions component using an OGI instrument, or an instrument reading of 500 parts per million by volume (ppmv) or greater from a fugitive emissions component using EPA Method 21 of appendix A-7 to 40 CFR part 60 (EPA Method 21). 40 CFR 60.5430b defines a fugitive emissions component as any component that has the potential to emit

[135] 89 FR 16871 (March 8, 2024).

fugitive emissions of methane or VOCs at a well site, centralized production facility, or compressor station. These devices include valves (including separator dump valves), connectors, pressure relief devices, open-ended lines, flanges, covers and CVSs not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping. Similarly, the EG OOOOc, 40 CFR 60.5430c contains comparable definitions for fugitive emission components, defined as any component that has the potential to emit fugitive emissions of methane at a well site, centralized production facility, or compressor station. This includes but is not limited to valves (including separator dump valves), connectors, pressure relief devices, open-ended lines, flanges, covers and CVSs not subject to 40 CFR 60.5411c, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5396c, compressors, instruments, meters, and yard piping.

For the NSPS OOOOb, owners and operators of affected facilities that contain fugitive emission components follow 40 CFR 60.5397b. Owners and operators of fugitive emission components at affected facilities must develop and follow the fugitive emissions monitoring plan for the site consistent with 40 CFR 60.5397b(b), conduct initial and ongoing fugitive emission monitoring surveys as provided in 40 CFR 60.5397b(f)-(g), repair any source of fugitive emissions that have been identified as provided in 40 CFR 60.5397b(h), and follow the proper recordkeeping and reporting procedures as specified in 40 CFR 60.5397b(k). In general terms, after the initial survey, this provision requires monitoring and repair for the five subcategories of well sites and compressor stations as follows:

- Single wellhead only well sites: Quarterly monitoring using AVO or any other detection method (*e.g.*, EPA Method 21, etc.).
- Multi-wellhead only well sites: Semiannual OGI (or EPA Method 21) monitoring and quarterly monitoring using AVO or any other method.

- Well sites or centralized production facilities with specified major production and processing equipment: Quarterly OGI (or EPA Method 21) monitoring and bimonthly monitoring using AVO or any other detection method.
- Small well sites: Quarterly monitoring using AVO or any other detection method.
- Compressor stations: Quarterly OGI (or EPA Method 21) and monthly monitoring using AVO or any other detection method.

The third subcategory includes well sites and centralized production facilities that have: (1) One or more controlled storage vessels or tank batteries; (2) one or more control devices; (3) one or more natural gas-driven process controllers or pumps; or (4) two or more pieces of major production or processing equipment not listed in items (1)–(3).[136]

Major production and processing equipment as defined in 40 CFR 60.5430b means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, control devices, natural gas-driven process controllers, natural gas-driven pumps, and storage vessels or tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

For the fourth category of small well sites, 40 CFR 60.5430b defines a small well site, for purposes of the fugitive emissions standards in 40 CFR 60.5397b and 40 CFR 60.5398b, as a site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. Small well sites cannot include any controlled storage vessels (or controlled tank batteries), control devices, natural gas-driven process controllers, or natural gas-driven pumps. The presumptive standards for EG OOOOc contain similar provisions for fugitive emissions components designated facilities under 40 CFR 60.5397c.

The March 2024 Final Rule requirements at 40 CFR 60.5397b(c)(2) and 40 CFR

[136] 40 CFR 60.5397b(g)(1)(iv)(A)-(D).

60.5397c(c)(2) do not specifically state that a combination of fugitive emissions monitoring techniques can be used to comply with the requirements, and reconsideration petitioners on the March 2024 Final Rule interpret the term "technique" (singular) used in 40 CFR 60.5397b(c)(2) and 40 CFR 60.5397c(c)(2) to mean that only one technique can be utilized in order to comply with the requirements.[137] Reconsideration petitioners expressed concerns with the clarity of the current rule on this point. *See* section III.E.2.a of this preamble for detailed descriptions of these concerns.

The March 2024 Final Rule also includes provisions for difficult-to-monitor and unsafe-to-monitor fugitive emissions components surveyed using EPA Method 21.[138] *See* 40 CFR 60.5397b(g)(2) and (3). No similar provisions exist for difficult- and unsafe-to-monitor fugitive emissions components monitored by other methods, such as AVO inspections. Reconsideration petitioners requested that the EPA clarify and add, as needed, provisions for AVO inspections like those provided for EPA Method 21. *See* section III.E.2.a of this preamble for discussion on EPA Method 21 specific provisions for AVO inspections.

The March 2024 Final Rule provides criteria at 40 CFR 60.5365b(i)(2) to determine, for the purposes of the fugitive emissions components, if a modification of a centralized production facility has occurred. The EPA received requests to revise the current modification criteria related to centralized production, with petitioners arguing that the criteria are inappropriate as these facilities often receive production from offsite wells operated by different entities, and the operator of the centralized production facility may be unaware of offsite activities that could trigger a modification. *See* section III.E.2.c of this preamble for discussion on modification criteria for centralized production facilities.

---

[137] 89 FR 16871-16872 (March 8, 2024).
[138] 40 CFR 60.5397b(g)(2) and (3).

Under the March 2024 Final Rule, the fugitive emissions monitoring requirements apply until the site completes the well closure requirements. These requirements include submission of a well closure plan that includes permanent plugging of all the wells at the site and submitting a well closure report.[139] Owners and operators need to submit the well closure plan within 30 days of the cessation of production from all wells located at the site.[140] The well closure plan must include a description of the steps necessary to close all the wells at the site, including permanently plugging those wells; a description of the financial requirements and disclosure of financial assurance to complete closure; and details on the schedule for completing all activities in the well closure plan.[141] Owners and operators are also required to submit a notification of intent to close the well site 60 days prior to starting well closure activities. 40 CFR 60.5397b(l)(2). A final OGI survey is required of the well site after completing the activities in the well closure plan, with requirements to take steps to eliminate emissions and resurvey the source if any emissions are imaged by the OGI instrument, and there are associated recordkeeping and reporting requirements. 40 CFR 60.5397b(l)(3)-(4). Reconsideration petitioners requested that the EPA revise the requirement to notify the Agency prior to well closure. *See* section III.E.2.d of this preamble for discussion on the well closure requirements.

2. Additional Background and Summary of Proposed Changes and Rationale

Reconsideration petitioners requested that the EPA reconsider certain issues related to the March 2024 Final Rule fugitive emissions monitoring requirements.[142] This section describes those requests raised in petitions for reconsideration that are relevant to this proposal.

---

[139] 40 CFR 60.5397b(g), 40 CFR 60.5397b(l).
[140] 40 CFR 60.5397b(l)(1).
[141] 40 CFR 60.5397b(l)(1).
[142] API-AXPC (2024b)..

Petitioners requested that the EPA allow operators to develop flexible, fit-for-purpose monitoring plans that use multiple detection technologies during each periodic survey. Petitioners also requested that the EPA add provisions for AVO surveys of difficult-to-monitor and unsafe-to-monitor fugitive emissions components. *See* section III.E.2.a of this preamble for further discussion on both of these issues.

In addition, petitioners asserted that the definition of a fugitive emissions component should reference certain provisions from NSPS OOOO and NSPS OOOOa in addition to the provisions already referenced from NSPS OOOOb. *See* section III.E.2.b of this preamble for further discussion of this issue, including petitioners' specific recommendations.

Furthermore, petitioners claimed that the modification criteria for fugitive emissions components affected facilities finalized in the March 2024 Final Rule are inappropriate for certain centralized production facilities in the gathering and boosting segment.[143] *See* section III.E.2.c of this preamble for further discussion of this issue.

Additionally, petitioners asserted that the timing components of the well closure notification requirements in the March 2024 Final Rule could impact an operators' ability to timely close the well. *See* section III.E.2.d of this preamble for further discussion of this issue.

a. Fugitive Emissions Monitoring Detection Technologies

Background. Petitioners requested that the EPA clarify that operators may use AVO, OGI, and/or EPA Method 21 as part of flexible, fit-for-purpose fugitive emissions monitoring plans. According to petitioners, the March 2024 Final Rule fails to clarify whether facilities can use multiple monitoring technologies or whether they need to use a single technology or method to demonstrate compliance. Petitioners also requested extensions of difficult-to-monitor and unsafe-to-monitor provisions for fugitive emissions

[143] API-AXPC (2024b).. pgs. 22-23.

monitoring surveys conducted using EPA Method 21 to fugitive emissions monitoring surveys performed using AVO.

Summary of Proposed Changes and Rationale. The EPA proposes to revise 40 CFR 60.5397b(c)(2) and 40 CFR 60.5397c(c)(2) of the regulatory text in NSPS OOOOb and EG OOOOc to refer to "technique(s)" (rather than "technique," in the singular) to clarify that owners and operators have the option to use multiple survey techniques to comply with requirements based on the appropriate component monitoring survey method used. The Agency notes that 40 CFR 60.5397b(c)(2) and 40 CFR 60.5397c(c)(2) already include the phrase "and/or", suggesting multiple techniques could be used. The EPA notes that several individual techniques can be used to determine fugitive emissions on their own, so using multiple techniques together can also meet the requirements of these provisions, as long as that use is otherwise consistent with the relevant regulatory requirements. As such, this proposed revision clarifies the EPA's original intent to allow usage of multiple monitoring methods rather than restrict owners and operators to a single method.

The NSPS OOOOb and EG OOOOc currently include difficult-to-monitor and unsafe-to-monitor provisions in 40 CFR 60.5397b(g)(2) and (3), and in 40 CFR 60.5397c(g)(2) and (3), when facilities use EPA Method 21 to conduct fugitive emissions monitoring surveys. Considering the petitioners' request in this regard, the EPA acknowledges their concern that conducting AVO inspections shares similar monitoring challenges to conducting monitoring using EPA Method 21 in terms of potential difficulties or safety concerns when completing the inspection. As with EPA Method 21 inspections, the operator must visually see components to conduct an AVO inspection, and this may require the use of a lift or may require access to potentially unsafe locations. While the EPA expects fewer components would meet the definition of difficult-to-monitor and unsafe-to-monitor during an AVO inspection given that AVO does not have

the same direct proximity requirements as EPA Method 21, the EPA recognizes the petitioners' concern that AVO inspections could pose similar difficulty and safety issues as those encountered when monitoring is conducted with EPA Method 21. Thus, the EPA proposes to amend 40 CFR 60.5397b(g)(2) and (3) and 40 CFR 60.5397c(g)(2) and (3) to include difficult- and unsafe-to-monitor provisions for AVO inspections that parallel those in the current rules for monitoring with EPA Method 21. The EPA solicits comment on this proposal. (Question III.4a)

In addition, for purposes of setting fugitive emissions monitoring requirements, the EPA seeks comment (including data and detailed information) on how often fugitive emissions are found at different types of sites, the approximate volume of gas emitted during a typical fugitive emissions event at each type of site, estimates regarding the approximate length of time that fugitive events last at these sites, and the cost of conducting fugitive emissions monitoring (e.g., capital costs, variable costs, changes to business practices, safety implications of conducting the fugitives monitoring, and any other relevant costs) . (Question III.4b)

The EPA is also soliciting comment on the cost effectiveness and cost reasonableness of monitoring requirements for fugitive emissions generally. The EPA is specifically requesting information on the appropriate frequency, type of monitoring technology, equivalent monitoring technologies for various equipment types, and other relevant information that may improve EPA's cost effectiveness and cost reasonableness analyses, allowing the EPA to better target of emission reductions and EPA also seeks comment whether the fugitive emissions monitoring requirements in the March 2024 Final Rule are necessary considering this information. The EPA also seeks comment on whether further distinctions or subcategorizations may be needed to appropriately target meaningful emissions reductions in a cost reasonable manner, including potential exemptions of certain subcategories. (Question III.4c)

b. Definition of Fugitive Emissions Component

Background. Reconsideration petitioners requested that the EPA revise the definition of fugitive emissions component in the NSPS OOOOb to include references to the relevant provisions of NSPS OOOO and NSPS OOOOa as it does for NSPS OOOOb, such that this definition would exclude covers and CVSs and thief hatches and other openings on a storage vessel, regulated under NSPS OOOO, NSPS OOOOa, or NSPS OOOOb, not just NSPS OOOOb. By way of a practical example, if the definition of fugitive emissions component excludes a thief hatch on an NSPS OOOOb applicable tank, fugitive surveys would not be required to include the thief hatch in the fugitive emissions survey conducted under 40 CFR 60.5397b. In this example, the EPA notes that this suggested change would not leave the thief hatch unregulated (*i.e.*, owners and operators would not be excluded from having to close an improperly opened thief hatch). In this case, the closed vent system and cover requirements of 40 CFR 60.5416b would require inspections (and closing) of the thief hatch, which take place on the same schedule as inspections conducted for fugitives monitoring.

Summary of Proposed Changes and Rationale. The EPA proposes to revise the definition of fugitive emissions component in NSPS OOOOb to include certain references to requirements under the NSPS OOOO and NSPS OOOOa, such that the fugitive emissions component definitions in NSPS OOOOb better align with the fugitive emissions component definition in NSPS OOOO and NSPS OOOOa. In particular, the proposed revisions would exclude thief hatches and other openings on a storage vessel, and covers and CVS components regulated under NSPS OOOO, NSPS OOOOa, or NSPS OOOOb from the definition of fugitive emissions component in NSPS OOOOb, not just those regulated under NSPS OOOOb.

The definition of a fugitive emissions component in 40 CFR 60.5430b currently reads:

> *Fugitive emissions component* means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, such as valves (including separator dump valves), connectors, pressure relief devices, open-ended lines, flanges, covers and CVSs not subject to [section] 60.5411b, thief hatches or other openings on a storage vessel not subject to [section] 60.5395b, compressors, instruments, meters, and yard piping.

The EPA proposes to revise the definition of a fugitive emissions component in 40 CFR 60.5430b to include exclusions from the definition for emission sources subject to other requirements under the rules, such that it would read as follows:

> *Fugitive emissions component* means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, such as valves (including separator dump valves), connectors, pressure relief devices, open-ended lines, flanges, covers and CVSs not subject to [sections] 60.5411, 60.5411a, or 60.5411b, thief hatches or other openings on a storage vessel not subject to [sections] 60.5395, 60.5395a, or 60.5395b, compressors, instruments, meters, and yard piping.

The CVS subject to 40 CFR 60.5411, 60.5411a, or 60.5411b and thief hatches or other openings on a storage vessel subject to 40 CFR 60.5395, 60.5395a, or 60.5395b include specific monitoring requirements such that these sources would be reasonably excluded from the definition of fugitive emissions component. In NSPS OOOOa, CVS subject to 40 CFR 60.5411 or 60.5411a, and thief hatches or other openings on a storage vessel subject to 40 CFR 60.5395 or 60.5395a are excluded from the definition of fugitive emissions component. Specifically, the EPA is proposing to include in NSPS OOOOb parallel exclusions from the definition of fugitive emissions component to maintain consistency across the NSPS OOOO family of rules. These proposed changes would align with the fugitive emissions component definition for emission sources regulated under different provisions in the NSPS OOOO family of rules and reflect the EPA's longstanding position that "devices that vent as part of normal operations are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission."[144]

[144] 89 FR 17043 (March 8, 2024).

The EPA also considered whether to include a parallel change to EG OOOOc in this proposal. To clarify, the EPA is not proposing to include references to NSPS OOOO, NSPS OOOOa or NSPS OOOOb in 40 CFR 60.5430c because the Agency expects sources subject to NSPS OOOO and NSPS OOOOa would be existing sources subject to EG OOOOc so that the exclusion for CVS and storage vessels subject to EG OOOOc is sufficient. The EPA also notes that for facilities with sources subject to NSPS OOOOb, the fugitive emission standards in NSPS OOOOb would apply rather than EG OOOOc, so an exclusion for CVS and storage vessels subject to NSPS OOOOb is not needed. Accordingly, this proposal does not include revisions to add references to NSPS OOOO, NSPS OOOOa or NSPS OOOOb in 40 CFR 60.5430c.

The EPA solicits comment on this proposal. (Question III.4d)

c. Modification Criteria for Centralized Production Facilities

Background. Reconsideration petitioners claimed that certain modification criteria (40 CFR 60.5365b(i)(2)) finalized in the March 2024 Final Rule for fugitive emissions components affected facilities are inappropriate for certain centralized production facilities that receive production from offsite wells because the centralized production facility operator may not know when an action is occurring at an offsite well that would trigger a modification at the centralized production facility.[145]

Petitioners asserted that, under the definition the EPA finalized for a centralized production facility in the March 2024 Final Rule, the operator of the centralized production facility may not be the same entity as the operator of the offsite wells that flow to that centralized production facility.[146] For this reason, the petitioners asserted that

[145] API-AXPC (2024b). pgs.22-24.

[146] See 40 CFR 60.5430b. "Centralized production facility means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized

the centralized production facility operator may be unaware of an action occurring at an offsite well that could trigger a modification at the centralized production facility, thus making the requirements finalized in 40 CFR 60.5365b(i)(2) untenable. Related to ownership of the wells versus ownership of the centralized production facility, the petitioners referenced the Response to Public Comments on the November 2021 Proposal and the December 2022 Supplemental Proposed Rule where the EPA stated:

> Regarding the comments that a centralized production facility may be owned by a different company than the well sites, this is not EPA's understanding of these sites. As discussed in the November 2021 Proposal, the centralized production facility definition was created, in part, to address the scope of fugitive emissions standards at well sites. The EPA described that these facilities are a type of well site; therefore, it is not the EPA's understanding for them to have a different owner. If the liquids have undergone custody transfer, then the operations described are no longer in the producing operations and would be a natural gas processing plant or a compressor station, depending on the scope of operations present at the site. The commenter did not provide rationale why this understanding is not correct.[147]

Petitioners claimed that, in the above response, the EPA correctly acknowledged that some centralized production facilities (as defined in NSPS OOOOb and EG OOOOc) may have also met the definition of well site under NSPS OOOOa. However, the petitioners stated that the EPA failed to acknowledge that the crude oil and natural gas source category is defined in 40 CFR 60.5430, 60.5430a and 60.5430b as:

> (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and
>
> (2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

---

production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

[147] U.S. EPA. (2023b). Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule (86 FR 63110, November 15, 2021; 87 FR 74702, December 6, 2022). *See* Response II-4-2.

Petitioners indicated that this definition of crude oil production includes operators in both the production segment and the gathering and boosting segment because both segments are upstream of a crude oil transmission pipeline or other forms of transportation. Petitioners stated that gathering and boosting operators may operate a centralized production facility and not operate the wells flowing to the centralized production facility. Petitioners also claimed that while transfer of ownership of the produced oil (or other hydrocarbon liquids) occurs, this transfer is different from the point of custody transfer to the crude oil transmission pipeline, or any other forms of transportation stated in the definition of the source category or as defined 40 CFR 60.5430b.[148]

Petitioners also stated that centralized production facilities are designed to collect and gather a maximum throughput capacity, meaning they are built to gather liquids from one or more well sites (similar to how a compressor station is built to gather natural gas from one or more well sites) and designed to continually operate at this capacity.

Summary of Proposed Changes and Rationale. The EPA acknowledges the petitioners' concerns regarding the March 2024 Final Rule modification criteria for centralized production facilities as related to fugitive emissions requirements. The Agency considered whether it is appropriate to propose changes based on the concerns raised relating to the modification criteria in 40 CFR 60.5365b(i)(2) and the receipt of liquids from offsite wells and has decided to propose the following amendments: First, the EPA proposes to amend the definitions of "well site" and "centralized production facility" to clarify the difference between a well site and a centralized production facility with respect to the receipt of liquids from one or more offsite natural gas or oil production wells. The EPA proposes to amend the definition for centralized production

[148] Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

facility to clarify that centralized production facilities may include one or more onsite wells. The EPA also proposes to amend the definition for well site to further clarify that a surface site that also receives liquids from one or more offsite natural gas or oil production wells is a centralized production facility, not a well site. Second, the EPA also proposes to amend the modification criteria in 40 CFR 60.5365b(i)(2) to describe the activities that would be classified as a modification at a centralized production facility for purposes of 40 CFR 60.5397b and 60.5398b. In addition to the currently codified instances where a new well is drilled at the existing centralized production facility or a well at an existing centralized production facility is hydraulically fractured or refractured, the EPA proposes that the following activities also would be classified as a modification: a) the existing centralized production facility receives additional fluids from an offsite well which cumulatively exceed the throughput prior to the receipt of additional fluids. Throughput prior to the receipt of additional fluids is throughput established in a legally and practicably enforceable (LPE) limit in an operating permit or other requirement established under a Federal, state, local, or Tribal authority; or projected maximum average daily throughput, which is determined using a generally acceptable engineering model (*e.g.*, volumetric condensate rates from the tank battery based on the maximum gas throughput capacity of each producing facility); b) the existing centralized production facility replaces or modifies one or more storage vessels such that the cumulative storage capacity of the existing centralized production facility increases; or c) one or more pieces of major production or processing equipment are added to the centralized production facility. In proposing changes to 40 CFR 60.5365b(i)(2), the EPA also proposes to delete the current modification criteria at 40 CFR 60.5365b(i)(2)(ii) and (iii) which state that a modification to centralized production facility occurs, in relevant part, if a well sending production to an existing centralized production facility is modified or a well site subject to 40 CFR 60.5397b or 60.5398b removes all major production and processing

equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility. The rationale for these changes is discussed below. The Agency notes that these revisions do not impact the modification criteria that apply to a well site under 40 CFR 60.5365b(i)(1). Wells that are located offsite, *i.e.*, wells that are not at the same surface site as the centralized production facility, are subject to those modification criteria, and if any of the activities specified in 40 CFR 60.5365b(i)(1)(i) through (iii) occur at those well sites, a modification to the well site would occur.

In the October 2018 Proposal to amend NSPS OOOOa, the EPA explained that emissions increases (for determining when a modification at a well site for the purposes of fugitive emissions occurs) result from two actions: the addition of processing equipment (and attendant fugitive emissions components) and increases in production rates.[149] The EPA explained that increased production will "generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components)."[150] The EPA also explained that additional fugitive emissions can also result from installation of additional equipment.[151] The EPA has not altered this understanding in subsequent rulemakings and continues to conclude that these two activities lead to emissions increases. In implementing these criteria for centralized production facilities in NSPS OOOOb and establishing the current modification criteria at 40 CFR 60.5365(i)(2), the EPA finalized criteria reflecting the same principle: that the addition of processing equipment (and attendant fugitive emissions components) and/or increases in production occur when a new well is drilled at an existing centralized production facility, a well at an existing centralized production facility is hydraulically

[149] 83 FR 52073 (October 15, 2018).
[150] 81 FR 35881 (June 3, 2016).
[151] 83 FR 52073 (October 15, 2018).

fractured or refractured, or a well sending production to an existing centralized production facility is modified by one of these actions (*i.e.*, adding a well or hydraulically fracturing or refracturing a well), or when a well site removes all major production and processing equipment and sends production to an existing centralized production facility. As part of today's action, the EPA is considering whether to revise the criteria for these modifications in NSPS OOOOb so that they reflect activities under the control of the operator of the centralized production facility, but still capture emissions increases resulting from the addition of processing equipment (and attendant fugitive emissions components) and/or increases in production.

First, the EPA reviewed our prior response to comment cited by the petitioners above, given information provided by the petitioners that the operator of a centralized production facility may not be the same entity as the well operator, which could result in the centralized production facility operator being unaware of activities occurring at an offsite well. [152] As discussed in the November 2021 Proposed Rule, the EPA structured the definition of centralized production facility to address, in relevant part, the scope of fugitive emissions standards for these types of facilities.[153] The EPA stated that "[o]ur intent is to limit the oil and gas production segment up to the point of custody transfer to an oil and natural gas mainline pipeline (including transmission pipelines) or a natural gas processing plant. Therefore, the collection of fugitive emissions components within this boundary are a part of the well site."[154] While proposing a separate definition for "centralized production facility" in the November 2021 Proposed Rule for the purposes of NSPS OOOOb, the EPA stated that "[t]he EPA continues to define these facilities as a

---

[152] U.S. EPA (2023b). Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule (86 FR 63110, November 15, 2021; 87 FR 74702, December 6, 2022). *See* Response II-4-2.
[153] 86 FR 63183 (November 15, 2021).
[154] 86 FR 63183 (November 15, 2021). Citing from the RTC to NSPS OOOOa. *See* U.S. EPA. (2016). EPA's Responses to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. May 2016. (page 4-194).

type of well site."[155] In the final definition of "centralized production facility" at 40 CFR 60.5430b, the EPA did not include "custody transfer" as a criterion to determine the boundary of the centralized production facility. Instead, the EPA stated by definition at 40 CFR 60.5430b and 60.5430c that centralized production facilities "are part of the producing operations." The EPA continues to maintain that view of centralized production facilities and is not proposing to change it in this action. In reviewing the prior RTC, where the EPA concluded that the centralized production facility and the wells sites producing to the centralized production facility had the same owner, and considering this updated analysis of the record, the EPA clarifies in this proposal that storage vessels and equipment at a single surface site which conduct the types of operations described in the definition of centralized production facility are a centralized production facility, regardless of ownership relative to the well sites producing hydrocarbons to the facility, provided they are located upstream of the natural gas processing plant or crude oil pipeline breakout station. For purposes of the fugitive emissions standards, these facilities remain part of the producing operations and are subject to the same fugitive emissions standards as well sites (rather than those applicable to compressor station facilities). This includes centralized production facilities owned by midstream companies (*e.g.*, gathering and boosting operators) in both the oil and natural gas sectors. In reviewing the RTC for the March 2024 Final Rule, the EPA also noted that the Agency had intended to make edits to the definitions of "centralized production facility" and "well site" in 40 CFR 60.5430b to clarify how these terms relate to one another and to avoid potential confusion arising from the potential overlap between them.[156] In particular, the RTC indicates that the Agency intended to clarify in the definition of centralized production facility that

[155] 86 FR 63183 (November 15, 2021).
[156] U.S. EPA. (2023b). Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule (86 FR 63110, November 15, 2021; 87 FR 74702, December 6, 2022). *See* Response II-4-15.

such a facility also may include one or more onsite wells, and to clarify in the definition of well site that if a site receives liquids from one or more offsite natural gas or oil production wells, it would fall within the definition of a centralized production facility (rather than a well site). Because those additions described in the prior RTC were not included in the relevant provisions of 40 CFR 60.5430b, the EPA is proposing to add them in this proposal.

Second, based on the EPA's review of the reconsideration petitions, the EPA now acknowledges that the operator of an offsite well may not be the same entity as the operator of the centralized production facility that gathers materials from offsite natural gas and oil production wells. Accordingly, the EPA is proposing to remove the modification criteria currently at 40 CFR 60.5365b(i)(2)(ii), which tie modification of a centralized production facility to a modification at an offsite well, because the operator of the centralized production facility may not be the same as the operator of the offsite well sending production to the centralized production facility. However, recognizing that modifications at offsite well sites can increase production sent to a centralized production facility and increase emissions, the EPA is proposing to add modification criteria for centralized production facilities that are tied to increased throughput from an offsite well. These proposed criteria differ from the current criteria (which require the owner or operator of the centralized production facility to know when a modification occurs at an offsite well), but the EPA believes the proposed criteria will still capture situations in which an emissions increase at the centralized production facility occurs due to increases in production that result from modifications at an offsite well. Specifically, the EPA is proposing that increases in throughput that cumulatively exceed the LPE limit on throughput or the projected maximum average daily throughput established for the centralized tank battery (*i.e.*, "design capacity") would qualify as a modification of the

centralized production facility.[157] The EPA is choosing throughput as a proxy for production because these two measures are closely related. An increase in production at the well site is manifested as throughput increases to a tank battery located at a centralized production facility. Production and throughput can be linked using generally accepted engineering models such as condensate rates derived from gas throughput. Throughput to the tank battery is already tracked, and various methods are available for measuring it. For tank batteries, the LPE limit on throughput is established in operating permits or in other Federal, state, local or Tribal requirements.

In developing these proposed modification criteria, the EPA reviewed how the Agency has previously addressed emissions increases related to production increases (manifested as throughput increases at tank batteries) in midstream operations that receive gas or liquids from other operations not owned or operated by the same entity, such as tank batteries at compressor stations. The EPA believes that examination of this information is relevant for modifications at centralized production facilities for the purposes of fugitive emissions components because the issues are similar: an operation receives liquids from other operations beyond their control. In the September 2020 Final Rule, the EPA explained its rationale for why different applicability criteria were appropriate for tank batteries in the midstream operations that are designed to receive liquids from multiple well sites over a longer period of time.[158] The EPA carried this rationale forward in the March 2024 Final Rule, for tank batteries located in the midstream operations, to require operators of those tanks to determine the potential for emissions using throughput established in a LPE permit or the projected maximum

[157] As discussed in section III.E. "Storage Vessels" the EPA is proposing changes for how throughput is determined for centralized production facilities to allow for the use of a LPE limit on throughput or the projected maximum average daily throughput.

[158] 85 FR 57404 (September 15, 2020). The discussion of the applicability and modification criteria for tank batteries germane for understanding how the EPA previously developed projected maximum average daily throughput determinations for the purpose of determining if an emissions increase based on throughput occurred.

average daily throughput.[159] Similarly, in the March 2024 Final Rule, the EPA finalized separate modification criteria for existing tank batteries located in the midstream operations at 40 CFR 60.5365b(e)(3)(ii)(D) which allows the increase in throughput to be compared to the same LPE limit on throughput or the projected maximum average daily throughput used in 40 CFR 60.5365b(e)(2)(iii). The EPA stated that such provisions should address the receipt of liquids from upstream production facilities owned by third parties.[160] The EPA now understands from the petitioners that, similar to compressor stations, centralized production facilities often are "overbuilt" to accommodate future production received from multiple well sites, and that while they can typically accommodate increases in throughput up to forecasted production used in the design, in some instances they are not in control of the offsite actions which increase that throughput. For this reason, the EPA now believes that the same rationale as the EPA used for midstream tank batteries also applies to tank batteries at centralized production facilities, which base their design on planned growth coming online over time to account for future growth, often beyond their control. Thus, for throughput changes brought on by actions (*e.g.*, drilling a new well or fracturing or refracturing a well) at offsite well sites feeding the centralized production facility, while the EPA previously thought that tracking those actions at the offsite wells would be a straightforward method to determine if production to the centralized production facility increased (without tracking throughput), the EPA now proposes that a more appropriate approach is to determine whether a production increase would result in an increase in emissions above the previously estimated emissions based on throughput increases beyond design capacity.

The EPA believes that using increases beyond a centralized production facility's design capacity appropriately captures emissions increases resulting from production-

[159] 40 CFR 60.5365b(e)(2)(iii).
[160] 89 FR 16982 (March 8, 2024).

related changes in the method of operation of the stationary source, consistent with the definition of "modification" in CAA section 111(a)(4).[161] This is because a centralized production facility is designed to accommodate the receipt of gases and liquids up to its permitted or design capacity. Under the proposed change, the EPA would not consider production increases that can be accommodated under the permitted or design capacity to constitute a change in the method of operation. Thus, the Agency is proposing that such increases would not trigger a modification, as that term is defined under CAA section 111(a)(4), unless accompanied by a physical change, such as adding a tank, adding additional major production equipment, or otherwise increasing capacity.[162]

In contrast, increases in production above the throughput established in an LPE limit or the design maximum average daily throughput, would be considered changes to the method of operation. Such increases are expected to cause emissions increases from fugitive emission components due to higher pressures, longer duration of flow, or more frequent flow events.[163] As discussed earlier in this preamble, the EPA has already established a procedure for determining when these increases occur, using the throughput that forms the basis for determining the potential for emissions and that is established in an LPE permit or the projected maximum average daily throughput. In this proposal, the EPA would use a parallel procedure as one method of determining whether a modification has occurred at a centralized production facility.

Third, the March 2024 Final Rule modification criteria at 40 CFR 60.5365b(i)(2)(iii) also address a production increase that occurs when an offsite well site becomes a wellhead only site and sends its production to an existing centralized

---

[161] As noted earlier in this preamble, under CAA section 111(a)(4) of the "term 'modification' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. 7411(a)(4).

[162] Modifications occurring from these actions are discussed later in this preamble.

[163] 83 FR 52073 (October 15, 2018). See discussion how increases in production rates causes an increase in molar flow rates and resulting increases in emissions from fugitive components.

production facility. The EPA proposes to delete this action from those modification criteria because, if the EPA finalizes the proposed change related to increases to throughput described above, that approach would already appropriately capture increases in throughput that occur when a well site transitions to a wellhead only site and sends its offsite production to the centralized production facility. As these changes in throughput would be measured against the proposed increase from the design capacity, retaining this standalone modification criterion would be redundant.

Fourth, there also are potential "hardware" changes at the centralized production facility that the EPA proposes to reflect in the modification criteria because they could result in an increase in fugitive emissions. These include the replacement or modification of one or more storage vessels such that the cumulative storage capacity is increased, as these changes could increase throughput beyond design capacity and thus would be considered modifications for the same reasons as discussed above. Other hardware changes that result in additional fugitive emissions include the addition of one or more pieces of "major production and processing equipment" (with attendant additional fugitive emissions components). Because emissions increases are associated with the addition of fugitive emissions components, the Agency is proposing that they would be considered modifications, even if they are not associated with an increase in throughput above design capacity. Further, the EPA recognizes that the addition of a new onsite well (with attendant fugitive emissions components) or the fracturing or refracturing of onsite wells are within the control of the operator of the centralized production facility and may also result in the addition of fugitive emissions components and thus lead to emissions increases. Accordingly, these are included in the proposed modification criteria as well.

The EPA believes that the proposed revisions to the modification provisions would continue to capture all instances in which emissions at a centralized production facility increase. However, these revisions would base that determination on actions

occurring at the centralized production facility itself. The EPA believes that the proposed revisions would appropriately focus the modification criteria on actions under the control of, or within the knowledge of, the operator of the centralized production facility rather than on actions occurring at offsite wells for which the operator may not have control or knowledge. The proposed changes are still expected to appropriately identify when there is an increase in VOC and methane emissions a) based on an increase in volumetric throughput above the design capacity to the centralized production facility; or b) when there are additional fugitive emissions components added, but the proposed changes do focus on information known by or actions under control of the centralized production facility.

The EPA solicits comment on this proposal. (Question III.4e)

d. Well Closure Requirements

Background. In the December 2022 Supplemental Proposal, the EPA proposed requirements for well closure plans, including a requirement that the operator must submit a notification to the EPA 60 days before beginning well closure activities.[164] The EPA did not receive comment on the 60-day notification timeline and finalized this requirement as proposed. Reconsideration petitioners claimed that the timing components of the EPA's well closure plan notifications could impact an operators' ability to timely close the well.[165] Petitioners explained that while many well closure activities are known in advance, in some instances, the opportunity may present itself without significant advance notice.

Summary of Proposed Changes and Rationale. The EPA acknowledges the petitioners' concerns that the requirement to submit a notification prior to the start of well closure activities could prevent the facility from permanently plugging the well in a

[164] 87 FR 74736 (December 6, 2022).
[165] API-AXPC (2024b). pgs. 23-24.

timely manner, for instance, if they had to delay commencement of well closure activities to meet the 60 day advance notice requirement. Based on these concerns, the EPA proposes to amend the well closure provisions at 40 CFR 60.5397b(l)(2) and 60.5397c(l)(2), and 40 CFR 60.5420b(a)(4)(ii) and 60.5420c(a)(3)(ii) to allow facilities the option to submit a notification after the well closure is complete. Specifically, the EPA proposes that the owner/operator can submit the notification of intent to close 60 days before beginning well closure activities, as currently required, or may alternatively have the option of submitting a notification of closure within, but not later than, 30 days after completing the final OGI survey, or resurvey, if applicable, conducted in accordance with 40 CFR 60.5397b(l)(3) or 60.5397c(l)(3). Operators that undertake well closure activities must submit the notification in accordance with 40 CFR 60.5420b(a)(4) or 60.5420c(a)(3), which requires that the notification includes contact information for the owner or operator; the United States Well Number; and the latitude and longitude coordinates for each well at the well site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983. In situations where the owner/operator elects to submit a notification of closure rather than a notification of intent to close, the EPA proposes that the notification of closure must also include an explanation of why a notification of intent to close could not be submitted 60 days before beginning well closure activities (*e.g.*, an explanation of why the notification requirement would have led to a delay in well closure activities). The proposed change provides additional flexibility in the submission of the notification of the well closure progress to ameliorate concerns that notification requirements could delay well closures. The EPA encourages owners/operators to conduct required well closure activities as expeditiously as possible to reduce the risk of continued emissions from unplugged idle wells.[166] The EPA believes that the proposed amendment incentivizes timely, well-

[166] 87 FR 74736 (December 6, 2022). See discussion of "Well Closure Plans."

executed closures without creating procedural barriers or subjecting operators to potential non-compliance, if the 60 day time frame for submitting a notice of intent to close cannot be met. The EPA further believes that submitting a notification of closure within 30 days after the final OGI survey or resurvey, if applicable, would not interfere with the schedule for the well closure activities themselves.

The EPA solicits comment on this proposal. (Question III.4f)

F. Storage Vessels

1. Background

NSPS OOOOb contains requirements for a storage vessel affected facility, defined as a tank battery that has the potential for VOC emissions equal to or greater than 6 tpy or methane emissions equal to or greater than 20 tpy. The 20 tpy methane threshold for applicability also applies to a tank battery under the EG OOOOc. A tank battery, according to at 40 CFR 60.5430b and 60.5430c, is "a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if only one storage vessel is present." Storage vessel affected facilities under NSPS OOOOb and designated facilities under EG OOOOc must determine their applicability (*i.e.*, the potential for VOC or methane emissions) and may include LPE limits in the determination. When determining the potential for VOC or methane emissions, operators of storage vessels not subject to LPE limits may exclude any vapor from that storage vessel which is recovered and routed to a process through a vapor recovery unit (VRU) operated in accordance with the cover and CVS requirements.

Under the March 2024 Final Rule, the applicability thresholds for tank batteries located at well sites and centralized production facilities are determined within 30 days of startup of production, or within 30 days after one of the actions described below relating to modifications. The applicability thresholds for tank batteries not located at a well site or centralized production facility (*e.g.*, tank batteries at onshore natural gas processing

plants) are determined prior to startup, or within 30 days of one of the actions described below relating to modifications, using throughput as determined by an LPE limit on throughput or the projected maximum average daily throughput.[167] The March 2024 Final Rule also established "modification" criteria to determine when an existing tank battery becomes subject to NSPS OOOOb. Under the March 2024 Final Rule, a "modification" of a tank battery occurs when: (1) a storage vessel is added to an existing tank battery; (2) one or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases; or (3) throughput to the tank battery increases, and the potential for VOC or methane emissions meets or exceeds the applicability thresholds of 6 tpy VOC or 20 tpy methane, respectively.[168]

The EPA is proposing changes to this definition of modification at 40 CFR 60.5365b(e)(3)(ii) based on our evaluation of petitioner concerns related to centralized production facilities. Petitioners claim that a centralized production facility operator may not know when an action is occurring at an offsite well that would trigger modification at the centralized production facility.[169] Petitioners raised a similar issue regarding modifications for the purposes of fugitive emissions components at centralized production facilities, which are discussed in Section III.E.2.c of this preamble ("Modification Criteria for [Fugitive Emissions at] Centralized Production Facilities"). In that section, the EPA examines the record relating to actions that trigger modifications at centralized production facilities. The discussion and rationale provided in that section, specific to actions which increase throughput, are relevant to tank batteries at centralized production facilities for the purpose of applying the modification criteria to tank batteries and are not repeated here. In parallel to proposing revisions to the modification criteria for tank batteries at a centralized production facility, the EPA also proposes

[167] 40 CFR 60.5365b(e)(2)(ii) and (iii) and 60.5386c(e)(2)(ii) and (iii).
[168] 40 CFR 60.5365b(e)(3)(ii).
[169] API-AXPC (2024b).

corresponding changes to the determination of the potential to emit for tank batteries at centralized production facilities. The proposed revisions would allow operators to base the potential for emissions on either the throughput as determined by an LPE or the projected maximum average daily throughput as specified in 40 CFR 60.5365b(e)(2)(iii). This approach would replace the current requirement to use the maximum average daily throughput to the tank battery measured over a 30-day period of production as specified in 40 CFR 60.5365b(e)(2)(ii). This proposed revision will make the determination of the potential for emissions consistent with the methodology provided for compressor stations and onshore natural gas processing plants, which recognizes that these types of facilities are built for planned growth (with additional receipt of fluids over time) and therefore the first 30 days of production does not accurately reflect the potential for emissions.

The EPA recognizes that other issues raised in reconsideration petitions on the March 2024 Final Rule related to storage vessel affected facilities are of interest to stakeholders. The EPA is still evaluating some of those other issues. One of those issues, for example, relates to the application of LPE limit criteria when determining the potential to emit VOC or methane from storage vessels when determining the applicability of NSPS OOOOb or EG OOOOc standards. While the EPA is not proposing any specific changes related to the application of LPE limit criteria in this action, the EPA is soliciting comment from stakeholders and the public on this specific issue. Depending on the comments the Agency receives, the EPA may take further action at an appropriate time, and relatedly, solicits further comment on whether the 2024 LPE criteria should be repealed along with supporting reasons for doing so. (Question III.5a)

Section III.F.3 of this preamble provides additional background on the application of LPE limit criteria when determining storage vessel applicability to standards and our solicitation of comment related to petitioner concerns on this issue. Aside from the definition of modification and the use of LPE for applicability, all other issues related to

the storage vessel provisions in the March 2024 Final Rule are out of scope for this proposal. The EPA may propose further changes to the storage vessel provisions in the future, but this action is limited to the two identified issues for storage vessels: modification of storage vessels at centralized production facilities and LPE for storage tanks (including tank batteries, individual tanks, tanks at centralized production facilities and tanks at individual well sites).

2. Application of the Definition of Modification to Centralized Production Facilities – Additional Background and Summary of Proposed Changes and Rationale

Background. Petitioners stated that the storage vessel modification provision as it relates to centralized production facilities is overbroad and inconsistent with the CAA. They challenge the conclusion that each of the specified events of 40 CFR 60.5365b(e)(3)(ii)(C) and (D) [increase in fluids received for well sites and centralized production facilities and non-well-site facilities, respectively] constitute a physical or operational change in the method of operation and cause an increase in emissions.[170,171] Petitioners also noted that they previously commented on the November 2021 Proposal arguing that not all of the specified events in paragraphs 40 CFR 60.5365b(e)(3)(ii)(A) through (D) constitute a physical change to the storage vessel. Within this comment on the November 2021 Proposal petitioners claim that these events are not operational changes because tanks and tank batteries in the sector are designed and operated to accommodate a wide range of conditions to reflect the varying and constantly changing operations they serve. Further, the petitioners stated that changes in throughput do not

[170] American Petroleum Institute (API) (2023). Letter to Michael S. Regan, EPA Administrator. RE: Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Including Appendix K and Social Cost of Greenhouse Gases. February 13, 2023.

[171] GPA Midstream Association (GPA) (2024). Petition. Letter to Michael S. Regan, EPA Administrator, et al. from GPA Midstream Association. Re: Petition for Reconsideration and Request for Stay of Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. May 2, 2024.

necessarily cause an increase in emissions under the EPA's long-established principles for determining emissions increases under CAA section 111.

For these reasons, one of the petitioners[172] contends that the EPA has underestimated the number of storage vessels that will be considered modified under the March 2024 Final Rule and has created significant and unfair compliance problems for operators. By way of example, they stated that midstream operators could potentially find themselves out of compliance on the March 2024 Final Rule's effective date as nearly all vessels have received additional volumes of fluids from upstream facilities since December 7, 2022.[173]

As noted in section III.F.1. of this preamble, the issues raised by petitioners related to the modification criteria as they apply to storage vessels at centralized production facilities are similar to concerns expressed regarding the March 2024 Final Rule modification criteria for centralized production facilities and its consequences for triggering a modification under the new source fugitive emissions requirements. Please also refer to section III.E.2.c of this preamble for a discussion of those related issues.

Summary of Proposed Changes and Rationale. In our December 2022 Supplemental Proposal preamble[174] and March 2024 Final Rule preamble[175] response to comments, the EPA specified events of 40 CFR 60.5365b(e)(3)(ii)(A) through (D) constitute a physical or operational change in the method of operation that result in an increase in emissions. The EPA also reiterated that the events noted in 40 CFR 60.5365b(e)(3)(ii)(A) through (D) trigger re-assessment of whether emissions from the

---

[172] GPA Midstream Association (GPA) (2024). Petition. Letter to Michael S. Regan, EPA Administrator, et al. from GPA Midstream Association. Re: Petition for Reconsideration and Request for Stay of Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. May 2, 2024.

[173] As noted in section II.E of this preamble, the EPA issued an IFR in July 2025, which extended the compliance deadline for these and certain other provisions. The IFR extended the modification provisions in 40 CFR 60.5365b(e)(3)(ii)(C) and (D) to January 22, 2027.

[174] 87 FR 74800, 74803 (December 6, 2022).

[175] 89 FR 16979, 16983 (March 8, 2024).

tank battery exceed one of the potential to emit (PTE) thresholds in 40 CFR 60.5365b(e)(1)(i) or (ii). If the additional throughput resulting from one of the events in 40 CFR 60.5365b(e)(3)(ii)(A) through (D) does not cause an exceedance of the potential for emissions thresholds, then a modification has not occurred.

Under the March 2024 Final Rule at 40 CFR 60.5365b(e)(3)(ii)(C), a modification occurs at an existing production facility or centralized production facility when a new well is added or a well which supplies liquid to the tank battery is fractured or re-fractured and the VOC or PTE threshold is met or exceeded. In the March 2024 Final Rule preamble[176] the EPA explained that "modifications" resulting from the receipt of additional throughput do not apply to tank batteries located at compressor stations or natural gas processing plants that have no control over the receipt of fluids from upstream production facilities owned by third parties. The requirements of this provision (40 CFR 60.5365b(e)(3)(ii)(D)) apply as long as the design capacity of the tank battery accounts for the additional throughput generated from one of these actions, such that the permit has already accounted for the emissions increase from the tank battery.

As discussed in detail in Section III.E.2.c ("Modification Criteria for [Fugitive Emissions at] Centralized Production Facilities") of this preamble, the EPA re-examined the record relating to throughput increases at centralized production facilities resulting from actions at an offsite well. In short, the EPA recognizes that the design of centralized production facilities allows for processing of fluids from numerous wells, some of which are off-site and beyond the control of the operator of the centralized production facility. For this reason, related to applicability determinations for centralized production facilities at 40 CFR 60.5365b(e)(2), the EPA believes that design throughput or throughput under LPE limit is a better means of assessing the potential to emit (similar to midstream tank batteries at compressor stations or gas processing plants) than the maximum average

[176] 89 FR 16982, 16983 (March 8, 2024).

daily throughput during the first 30 days of production (or within 30 days after triggering the emission potential assessments after an action which could result in a modification). Therefore, consistent with the rationale in Section III.E.2.c of this preamble for the proposed amendments to the modification criteria for centralized production facilities in 40 CFR 60.5365b(i) to allow the use of throughput established via LPE limits or to allow the use of projected maximum average daily throughput, the EPA proposes to amend the modification provisions at 40 CFR 60.5365b(e)(3)(ii)(C), to delete the reference to centralized production facilities. The result of this proposed change would be that the provisions requiring emission potential assessment based on first 30 days of production and reassessment with the addition of production well or refracturing a well would only apply to tank batteries located at a well site and would not apply at a centralized production facility. The EPA also proposes to amend 40 CFR 60.5365b(e)(3)(ii)(D) to treat centralized production facilities the same as compressor stations and onshore natural gas processing plants for the purposes of determining if a modification has occurred. To enable these proposed changes, the EPA also proposes changes to the potential for VOC or methane emissions at 40 CFR 60.5365b(e)(2)(ii) and (iii) so that the same throughputs are used in the initial PTE determination as will be used in the modification determination. Specifically, the EPA proposes to amend 40 CFR 60.5365b(e)(2)(ii) to delete the reference to centralized production facilities, and to amend 40 CFR 60.5365b(e)(2)(iii) to add the reference to centralized production facilities. Thus, the Agency is proposing that for each tank battery not located at a well site, including each tank battery located at a centralized production facility, compressor station, or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the centralized production facility, compressor station, onshore natural gas processing plant, or other facility based on the throughput established via LPE limits or the projected maximum average daily throughput for the tank battery

and reassess the potential emissions if the actual throughput for the tank battery exceeds the throughput used in the initial assessment (or most recent assessment if a previous re-assessment occurred). The EPA proposes similar edits in EG OOOOc at 40 CFR 60.5386c(e)(2)(ii) and (iii), so the determination of potential for emissions at tank batteries at centralized production facilities matches those for tank batteries at compressor stations and natural gas processing plants rather than tank batteries at well sites.

The EPA believes that these proposed amendments provide clarity for the modification trigger across all midstream storage vessels. For midstream storage vessels, including storage vessels at centralized production facilities, operators would only trigger a re-assessment of the potential for emissions threshold if actual throughput exceeds the projected maximum average daily throughput (or the throughput established in an LPE limit) used in the most recent potential for emissions calculation. The EPA also acknowledged in the July 2025 IFR preamble that the modification provisions finalized in the March 2024 Final Rule contain a degree of vagueness that allows for far more midstream storage vessels to trigger modification than the EPA estimated.[177] The EPA did not anticipate that these provisions would affect as many sources as petitioners have asserted. The EPA expects this proposed revision to address petitioner concerns related to the number of storage vessel tank batteries at centralized production facilities that were considered "modified" under the March 2024 Final Rule. It also addresses petitioner concerns that changes in upstream operations unbeknownst to the midstream operator could cause a large number of sources to be deemed "modified" and potentially out of compliance. The EPA solicits comment on this proposal. (Question III.5b)

3. Legally and Practicable Enforceable Limit Criteria – Additional Background and Solicitation of Comment

[177] 90 FR 35975 (July 31, 2025) (July 2025 IFR).

Background. Under 40 CFR 60.5365b(e)(2) of the NSPS OOOOb final rule, individual storage tanks and tank batteries may take into account a LPE limit for VOCs and/or methane in a State permit, general permit, or permit-by-rule when determining a tank or tank battery's PTE for purposes of rule applicability. The March 2024 Final rule includes six criteria to determine what constitutes an LPE limit:

- A quantitative production limit and quantitative operational limit(s) for the equipment, or quantitative operational limits for the equipment;
- An averaging time period for the production limit, if a production-based limit is used, that is equal to or less than 30 days;
- Established parametric limits for the production and/or operational limit(s), and where a control device is used to achieve an operational limit, an initial compliance demonstration (*i.e.*, performance test) for the control device that establishes the parametric limits;
- Ongoing monitoring of the parametric limits that demonstrates continuous compliance with the production and/or operational limit(s);
- Recordkeeping by the owner or operator that demonstrates continuous compliance with the limit(s); and
- Periodic reporting that demonstrates continuous compliance.

One petitioner stated that while they agreed that unenforceable voluntary actions inadequately limit a storage vessel's PTE, they believe that the LPE limit criteria promulgated in the March 2024 Final Rule go well beyond the criteria necessary for enforceability, overly burden industry, and supplant State permitting authority.[178]

[178] Texas Oil & Gas Association (TXOGA). (2024). Petition. Letter to Michael S. Regan, EPA Administrator, from TXOGA. Request for Reconsideration of the EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review." May 2, 2024.

Petitioners also raised several concerns related to the LPE limit criteria included in the March 2024 Final Rule.[179] Petitioners noted that all NSPS OOOO rules prior to the March 2024 Final Rule allow operators to reduce the potential for emissions where a LPE limit applies and limits the storage vessel's maximum production or operating capacity. See 40 CFR 60.5365(e), 60.5365a(e)(1), 60.5365b(e)(2), 60.5386c(e)(2). Petitioners explained that an LPE limit may exist in an operating permit or other requirement established under a Federal, State, local, or Tribal authority. However, they stated that the NSPS OOOOb and EG OOOOc define what constitutes an LPE limit. Under this LPE limit definition in NSPS OOOOb and EG OOOOc, the petitioners claimed that few, if any, existing permits or regulatory requirements contain all of the necessary criteria. Petitioners asserted that the practical impact is that, until State and local agencies revise their regulations and/or permits, operators will not have LPE limits to reduce the potential for emissions, despite many of those storage vessels actually being subject to emissions control requirements. Consequently, the petitioners argued that many storage vessels will become subject to the NSPS OOOOb or EG OOOOc where the actual emissions are below the applicable VOC and/or methane emissions thresholds. Additionally, the petitioners asserted that, even if permits or regulations were subsequently revised to meet the new criteria, storage vessel affected facilities and designated facilities cannot use the revised permit or regulatory LPE limit to redetermine and avoid continued applicability because of the "once-in, always-in" provision at 40 CFR 60.5365b(e)(4) and 60.5386c(e)(3). According to the petitioners, this situation applies even where the LPE limit adds only an administrative LPE limit element like periodic reporting (*i.e.*, a requirement that does not impact source operations). Petitioners contend that as a result, the new Federal standards supersede State and local emission control requirements and

[179] API & AXPC (2024b); and TXOGA (2024).

negate the extensive resources expended by these agencies and stakeholders to develop and implement those requirements.

Petitioners also claimed that the March 2024 Final Rule fails to clarify that a VOC emissions limit may serve as a surrogate for methane emissions where VOC and methane exist in the emissions stream (*i.e.*, a reduction in VOC emissions results in functionally the same reduction in methane emissions).[180] While the petitioners acknowledged that this clarification would not solve all of the issues with the LPE limit definition, they suggested that it would address this one aspect of their concerns.

Petitioners also asserted that the LPE limit criteria conflicts with the regulatory standard for "maximum average daily throughput" and PTE calculation procedure under the rule.[181] Petitioners explained that the LPE limit criteria employs a less than 30-day averaging time period as opposed to the typical standard in air permitting of a rolling 12-month average. In response to petitioner concerns related to this issue, the EPA stated in the March 2024 Final Rule preamble that a 30-day averaging time period is necessary because, under the rule, a PTE determination must occur within the first 30 days of startup.[182] In other words, the petitioners contend that the EPA uses the rule's arbitrary 30-day deadline to calculate the PTE as reasoning despite the fact that a 12-month rolling average better represents a source's actual PTE and allows better consistency with air permitting standards.

Petitioners also expressed concerns regarding the LPE limit criteria finalized in the March 2024 Final Rule related to the reporting requirements and performance testing required to establish parametric limits.[183] Specifically, petitioners stated that the reporting requirements are an unnecessary enforcement tool if facilities need to maintain records

---

[180] TXOGA (2024).
[181] *Id*.
[182] 89 FR 16979 (March 8, 2024).
[183] TXOGA (2024); and API & AXPC (2024b).

and make them available upon request. Further, they argued that the LPE limit criteria is inappropriate for minor sources, such as storage tanks. In particular, they objected to requiring performance testing to establish parametric limits for a limit to qualify as an LPE limit, as well as the requirement for continuous compliance monitoring with those limits.

Summary of Comment Solicitation. The EPA continues to assess the petitioners' concerns related to the application of LPE limit, and the Agency solicits comment from stakeholders and the public on their suggested changes to address their concerns. Specifically, the EPA solicits comment on whether any of the following changes suggested by petitioners would lead to unmitigated emissions increases and/or loopholes or whether they could lead to similar emission outcomes as the current rule while being more workable in practice:

- Revise the LPE limit criteria in NSPS OOOOb and EG OOOOc to match the language used in NSPS OOOO and NSPS OOOOa. (Question III.5c)
- Maintain the LPE limit criteria included in the March 2024 Final Rule but clarify that a VOC emissions limit may serve as a surrogate for methane emissions where VOC and methane are present in the emissions stream. (Question III.5d)
- Revise the calculation required for the PTE to be a 12-month rolling average to be more consistent with air permitting standards, such as title V. (Question III.5e)
- Remove reporting requirement in 40 CFR 60.5365b(e)(2)(i)(F), but continue to require owners and operators to maintain records and make them available upon request. (Question III.5f)
- Remove the requirement in 40 CFR 60.5365b(e)(2)(i)(C) for performance testing to establish parametric limits and the associated requirements in 40

CFR 60.5365b(e)(2)(i)(D) to do continuous compliance monitoring of those parametric limits. (Question III.5g)

- Maintain the LPE limit criteria included in the March 2024 Final Rule but clarify that operators may use an LPE production limit that accounts for annual production decline in combination with an operational limit. (Question III.5h)

The EPA is also requesting comments on the real world impact of the current LPE requirements on storage vessel applicability determinations, including information: on (1) the number of storage vessels that could become subject to NSPS OOOOb or EG OOOOc solely because existing state permits or regulatory requirements do not include all six elements of the current LPE limit definition despite these vessels having actual emissions below the applicable VOC or methane thresholds; 2) the cost to operators and state agencies of revising existing permits and regulations to meet the current six element criteria; (3) whether existing state permitting programs achieve equivalent environmental outcomes to the federal LPE criteria without the specific elements at issue; (4) the timeline required for states to amend their permitting and regulatory programs to incorporate the current LPE limit criteria; and (5) whether, given the above, a full repeal of the March 2024 Final Rule LPE limit criteria may be merited. (Question III.5i)

4. Safety Concerns Related to Flaring Requirements at Shut-In Wells

The EPA recognizes that petitioners may have other issues with storage vessels beyond the ones indicated in section III.F.1 through III.F.3 of this preamble. For example, one petitioner[184] described concerns regarding the operation of control equipment during periods when a well site is shut-in. Specifically, the commenter discussed the operation of an ignition source (*i.e.*, continuously operated flares) for

[184] API (2025). Re: Request for Administrative Reconsideration of EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities" - NSPS OOOObc. September 12, 2025.

control of storage vessels. The petitioners raise concerns that during these events, there is potential for the flame to migrate from the flare to the storage vessels, due to the system operating at lower than typical operating pressures, which could result in a tank explosion.

The EPA acknowledges the potential risk but does not have the necessary information to fully address this petition. Therefore, we solicit comments on how often NSPS OOOOb storage vessel affected facilities are shut-in, the reasons for the shut-in, and the length of a typical shut-in. We solicit comment on information regarding explosions of an NSPS OOOOb storage vessel affected facility as well as any near misses. We also solicit comment on whether an owner or operator of a storage vessel affected facility should be exempt from operating a control device when a shut-in occurs and whether there are additional work practices that could be put in place to minimize emissions during these events (Questions III.5j-III.5k).

The EPA also solicits comment on the change in emission profile of a storage vessel affected facility after a shut-in and whether the shut-in emission profile is under 6 tpy of VOC or 20 tpy of methane. The EPA solicits comment on whether sites subject to a temporary shut-in could recalculate their PTE to determine the need for storage vessel control. Finally, the EPA solicits comment on whether sites subject to a temporary shut-in could be subject to an alternative standard (tons per day of VOC/tons per day of methane) to determine the need for storage vessel control (Questions III.5l-III.5n).

G. Covers and CVSs

1. Background

Under the March 2024 Final Rule, the NSPS OOOOb and EG OOOOc final standards include requirements for CVSs. CVSs route emissions from wells (*i.e.*, oil wells when routing associated gas to a control device), process controllers, pumps, centrifugal compressors, reciprocating compressors, and storage vessel affected and

designated facilities to a control device or to a process. In addition, NSPS OOOOb and EG OOOOc include cover requirements to ensure compliance with the standards for centrifugal compressors, reciprocating compressors, and storage vessel affected and designated facilities.

Under the March 2024 Final Rule, each CVS must be designed and operated to capture and route all gases, vapors, and fumes to a process or to a control device and comply with an emissions limit of no identifiable emissions (NIE). NIE "means, for the purposes of covers, CVSs, and self-contained natural gas-driven process controllers and as determined according to the provisions of 40 CFR 60.5416b[185], that no emissions are detected by AVO means when inspections are conducted by AVO; no emissions are imaged with an OGI camera when inspections are conducted with OGI; and equipment is operating with an instrument reading of less than 500 ppmv above background, as determined by EPA Method 21 of appendix A-7 to this part when inspections are conducted with EPA Method 21."[186]

Covers must form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel, over the centrifugal compressor wet seal fluid degassing system, or over the reciprocating compressor rod packing emissions collection system. Each cover opening must be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed, except during those times when it is necessary to use an opening, such as to inspect equipment or to remove material from the equipment.

The March 2024 Final Rule also includes initial and continuous compliance requirements with the NIE requirement through OGI or EPA Method 21 monitoring and AVO inspections conducted at the same frequency as the fugitives emissions monitoring

[185] The cite is 40 CFR 60.5416c for EG OOOOc.
[186] *See* 40 CFR 60.5430b and 60.5430c.

for the type of site where the CVS and cover are located.[187] The EPA stated in the March 2024 Final Rule that emissions detected by AVO, OGI, or EPA Method 21 constitute a deviation of the NIE requirement until a subsequent inspection determines that the CVS and cover operate with NIE.[188] The EPA also discussed, in the December 2022 Proposed Rule, that "[a]ny identified emissions would be a violation of this [NIE] emissions limit . . ."[189] Each CVS requires inspection to ensure that the CVS operates with NIE initially within 30 calendar days after startup of the affected facility routing emissions through the CVS and periodic inspections, thereafter.[190]

CVSs and covers require annual NSPS OOOOb and EG OOOOc reporting.[191] Required records include the date of the inspection, the method of inspection (*i.e.*, visual, AVO, OGI, or EPA Method 21), and identification of all defects and emissions found.[192] For each defect or emission found, the owner or operator must record the location, a description of the defect, the maximum concentration reading if EPA Method 21 is used, the date of detection, the date of each attempt to repair the defect or emission, the corrective action taken to repair the defect or emission, and the date of final repair of the defect or emission. If a repair is delayed, the owner or operator must record the reason for delay and the anticipated date of repair.

2. Additional Background and Summary of Proposed Changes and Rationale

Background. Petitioners asserted that the NIE requirement applicable to covers and CVSs lacks reasoning, pathways to reasonably meet requirements, and technical feasibility over the long-term.[193] Petitioners contended that fugitive leaks from covers and

---

[187] Alternatively, the owner or operator may demonstrate compliance using periodic screening or continuous monitoring requirements for advance methane detection technologies in 40 CFR 60.5398b or 60.5398c.
[188] *See* 40 CFR 60.5416b(b)(2) through (4) and 60.5416c(b)(2) through (4).
[189] 87 FR 74805 (December 6, 2022).
[190] *See* 40 CFR 60.5416b(a) and 60.5416c(a).
[191] *See* 40 CFR 60.5420b(b)(11) and 60.5420c(b)(10).
[192] *See* 40 CFR 60.5420b(c)(8) through (10) and 60.5420c(c)(7) through (9).
[193] API & AXPC (2024a); GPA (2024); TXOGA (2024); INGAA (2024b). Supplemental Letter to Petition for Reconsideration of Final Rule. October 15, 2024; and API & AXPC (2024b).

CVSs occur in the same way as fugitive leaks covered by the equipment leak provisions. Petitioners also stated that the EPA previously rejected the applicability of numeric emissions limitations to fugitive emissions components. Petitioners noted comments made on the December 2022 proposed rule arguing that the requirement to operate with NIE applies as a work practice standard. Petitioners asserted that they also raised concerns with the NIE requirement in the rulemaking process and contended that the EPA declined to address these concerns and did not discuss the consequences of imposing what they allege is a technically infeasible requirement. Petitioners asserted that the EPA's approach effectively creates per se rule violations and that the NIE requirement is contrary to determining the BSER because no single facility has "adequately demonstrated" the BSER.

Petitioners also asserted that an NIE requirement is impossible to meet in practice, because leaks inevitably occur due to normal wear and tear (*e.g.*, a rusty bolt causing a flange leak) and often occur through events that are not reasonably within the control of the operator. Petitioners asserted that as fugitive emissions occur over time, an LDAR program allows operators to address them promptly and responsibly. For this reason, petitioners stated that the rule should differentiate between leaks appropriately attributed to the operator (*e.g.*, forgetting to close a thief hatch) versus leaks that are truly fugitive in nature, and that a violation should not occur from routine fugitive emissions as long as the appropriate action is taken. Petitioners asserted that the EPA should determine that covers and CVSs are subject to a work practice standard, not a zero emissions standard. Petitioners also requested that the EPA determine that pumps and valves required to be operated with "no detectable emissions" (NDE) are subject to a work practice standard, not a zero-emission standard, under the alternative standards for process unit equipment affected facilities.[194]

---

[194] *See* 40 CFR 60.5401b.

In addition, petitioners requested that the EPA confirm that "deviations" are not necessarily "violations" and that a leak from a cover or CVS may represent a deviation but not necessarily a violation of the NIE requirement. The petitioner cited the 40 CFR part 71 title V permitting rules which provide that "[a] deviation is not always a violation."[195]

Finally, petitioners contended that the NIE requirement could have adverse emission effects because it disincentivizes the use of new detection methodologies and voluntary emissions detection efforts.

Summary of Proposed Changes and Rationale. The EPA now recognizes that even under the best scenarios, components on the CVS and cover are subject to wear and tear, and that some emissions may be beyond the control of the operator. The Agency therefore proposes that such emissions are addressed through routine monitoring and repair requirements, and that a detection of emissions does not constitute an immediate deviation, but the source instead will have the opportunity to repair.[196].For these reasons, the EPA believes that changes to the March 2024 Final Rule's requirements for covers and CVS can be made that would maintain robust design requirements, while allowing for flexibility in repairing emissions and defects related to normal wear and tear, without subjecting the source to immediate non-compliance.

The EPA proposes changes to 40 CFR 60.5411b and 60.5411c to create two-fold design and operational requirements for covers and CVSs. The first part of the requirement is the design requirement. The EPA proposes to remove the requirement at 40 CFR 60.5411b(a)(3) and (b)(4) and 60.5411c(a)(3) and (b)(4) that CVSs and covers are designed with NIE. The EPA proposes no changes to any other design requirements

---

[195] *See* 40 CFR 71.6(a)(3)(iii)(C).

[196] The requirement to record and report defects and emissions still would apply as well as the requirement to report and record each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

in 40 CFR 60.5411b and 40 CFR 60.5411c. Specifically, for CVSs, these design requirements that the EPA is not proposing to remove require per 40 CFR 60.5411b(c) and 60.5411c(c) that the CVS be "of sufficient design and capacity to ensure that all gases, vapors, and fumes from the affected facility are routed to the control device or process and that the control device or process is of sufficient design and capacity to accommodate all emissions from the affected facility" and require that a design certification is submitted. Similarly, for covers, the design requirements that the EPA is not proposing to remove are the requirements at 40 CFR 50.5411b(b)(1) and 60.5411c(b)(1) that the "cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid," the requirement at 40 CFR 60.5411b(b)(2) and 60.5411c(b)(2) that "each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed" (with some operational exceptions), and the requirement at 40 CFR 60.5411b(b)(3) and 60.5411c(b)(3) that "storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions".

The second part of the current regulatory standard includes the requirement to operate the CVS and cover with NIE. The EPA proposes no changes to this operational requirement in 40 CFR 60.5411b(a)(3) or 60.5411c(a)(3) and 60.5411b(b)(4) or 60.5411c(b)(4), for CVS and covers under NSPS OOOOb and EG OOOOc, respectively. The EPA does, however, propose changes to the initial and continuous cover and CVS inspection and monitoring requirements at 40 CFR 60.5416b and 60.5416c. First, the EPA proposes to add the phrase "and repair" to the inspection procedures of 40 CFR 60.5416b(a) and 60.5416c(a) in order to specify that the design and operational requirements are met through both inspections and repairs. In this same Preamble section,

the EPA proposes to specify that the inspections and repair procedures are used to demonstrate compliance with both design and operational requirements for the CVS or cover (changed from demonstrating that the CVS or cover operates with NIE).

The EPA also proposes changes to the NIE test methods and procedures in section 40 CFR 60.5416b(b) and 60.5416c(b). First, the EPA proposes new criteria which demonstrate compliance with the operational NIE requirements. Through these revisions, the EPA proposes that NIE would mean operating with no emissions or defects, or when emissions or defects are found, facilities make repairs within the required timeframes or meet the delay of repair provisions when applicable. Next, in the repair provisions of 40 CFR 60.5416b(b)(5) and 60.5416c(b)(5), the EPA proposes a timeframe for repair of 24 hours, without an option for delay of repair. If a source cannot repair the emissions or defect within 24 hours, to avoid recording such emissions as deviations, they must make repairs as soon as practicable, which includes making a first attempt at repair no later than 5 days of detecting the emissions or defect and the final repair made within 30 days of detecting the emissions or defect, or they may put the source of emissions or defect on delay of repair, if the conditions for delay of repair (*e.g.*, repair is technically infeasible without a shutdown) are met. While the longer timeline for repair is a pathway to compliance with the operational NIE requirement, the EPA proposes to alter its position stated in the preamble of the March 2024 Final Rule that "any identified emissions would be a deviation of this emissions limitation" and proposes that a deviation of the design requirement would occur when emissions or defects are found, and the repairs are not made in the 24-hour timeframe.

For chronic leaks occurring during a year on the CVS or cover, the EPA proposes an investigative analysis. The EPA proposes that after the third emissions event in a year from the CVS or cover, an investigative analysis must be conducted within 10 days after the third emissions event or defect to determine if operation, maintenance, failure to

repair, or design cause(s) caused the emissions event or defect. If the emissions event or defect is determined to be due to design cause(s), the EPA proposes that such situation constitutes a deviation of the design requirements for CVSs and covers. If the emissions or defect is determined to be due to a failure to adequately repair the source of the emissions or defect during the prior repair attempts, the EPA proposes that this situation constitutes a deviation of the repair requirements. If the facility determines emissions or defects are caused by operation, maintenance, or other cause(s), this situation constitutes a deviation of the operational requirements of the CVS or cover. The EPA proposes that the facility must determine the number of emissions or defects detected in a year on a rolling quarterly basis after the first year (*i.e.*, count the number of emissions or defects detected in the current quarter and add to the three previous quarters).

As part of the investigative analysis, the EPA also proposes that the owner or operator must determine necessary design, equipment, operation, or other modifications to the CVS or cover to ensure that the owner or operator meets design and operational requirements. The EPA proposes that the changes must be implemented no later than 90 days after completion of the investigative analysis for design flaws, and no later than 30 days after completion of the investigative analysis for other causes.

The EPA proposes similar changes in 40 CFR 60.5390b and 60.5394c for process controllers which route emissions to a process through a CVS, or which comply with a self-contained process controller which operates with NIE. The EPA proposes that a process controller which routes emissions through a CVS to a process will be subject to the same requirements proposed above for CVSs. The EPA proposes that self-contained process controllers operate with NIE, which includes either no emissions or defects detected, or if emissions or defects are detected, the facility repairs the emissions or defects within the expedient timeline described above for covers and CVSs. The EPA also proposes that the investigative analysis described above for covers and CVSs applies

for process controllers which experience at least three emissions events or defects in a year (to be determined on a rolling quarterly basis after the first year). The EPA proposes to include the design requirement to "release gas to the downstream piping and not to the atmosphere, resulting in zero methane and VOC emissions" with current specifications in the regulatory definition of "self-contained process controller" at 40 CFR 60.5430b, in the compliance requirements for process controllers at 40 CFR 60.5390b(a)(2) and 60.5394c(a)(2).

The EPA proposes amendments to the repair requirements in 40 CFR 60.5416b(b)(5) and 60.5416c(b)(5) for CVSs, covers, and process controllers to align them with the repair provisions for fugitive emission sources and equipment leak sources at gas plants. Specifically, the EPA proposes that if the repair cannot be made within 24 hours of when the leak or defect is initially found, the facility must take a digital photograph of the source of the leak or defect, identify the source of the leak or defect on a process and flow instrumentation diagram, or tag the source of the leak or defect during the inspection at the leak or defect's time of discovery, for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the source of the leak or defect by location within the site (*e.g.*, the latitude and longitude of the source of the leak or defect or by other descriptive landmarks visible in the picture). The EPA also proposes that the identified source of leaks or defects from the CVSs, covers, and process controllers must be resurveyed within the same 24 hours of repair to ensure there are no leaks or defects after the repair. For sources with leaks identified using AVO, the facility may resurvey using either AVO, EPA Method 21, or OGI in accordance with 40 CFR 60.5397b(c)(7) or 60.5397c(c)(7). For sources with leaks identified using EPA Method 21 or OGI (except leaks at onshore natural gas processing plants), facilities may conduct the resurvey using either EPA Method 21, or OGI in accordance with 40 CFR 60.5397b(c)(7) or 60.5397c(c)(7). The

facility must resurvey each source of leaks at onshore natural gas processing plants using either EPA Method 21 or OGI in accordance with Appendix K of 40 CFR part 60.

Facilities may use alternative technology requirements of 40 CFR 60.5398b and 60.5398c to monitor CVSs and covers. While the EPA proposes no amendments to the underlying periodic and continuous monitoring alternative technology requirements in the March 2024 Final Rule in this proposal, the EPA proposes conforming edits to the repair timelines and investigative analysis when using alternative technologies. Monitoring surveys using approved periodic screening already reference, at 40 CFR 60.5398b(b)(5)(v) and 60.5398c(b)(5)(v), the repair requirements in 40 CFR 60.5416b(b)(5) and 60.5416c(b)(5), and the EPA proposes that these amendments also apply to repair of emission and defects of CVSs and covers found by alternative technologies. To conform the referenced repair requirements in 40 CFR 60.5416b(b)(5) and 60.5416c(b)(5) when using alternative technologies, the EPA proposes to amend 40 CFR 60.5398b(b)(5)(v) [197] to state that "[w]here the phrase "after the emissions or defect is detected" is used in §60.5416b(b)(5), the phrase "after receiving the results of the periodic screening in paragraph (b)(5)(i) of this section" shall be used." The EPA proposes that the proposed investigative analysis for chronic leakers in 40 CFR 60.5416b and 60.54165c also applies when periodic monitoring using alternative technology finds chronic leakers.

The EPA proposes conforming amendments in the reporting and recordkeeping sections at 40 CFR 60.5420b and 60.5420c to add recordkeeping and reporting of the resurvey results, identification of leaks which facilities consider unrepairable in the expedient timeline (*e.g.*, tagging), deviations of the design or NIE requirement, and records and reports relating to the investigative analysis including the date of the investigative analysis and date of implementation of the modifications. The EPA also

[197] As similar change is proposed for §60.5398c(b)(5)(v).

proposes conforming amendments to 40 CFR 60.5424b(c) and 60.5424c(c) to include records relating to the investigative analysis conducted in accordance with 40 CFR 60.5416b(b)(10) or 60.5416c(b)(10), when applicable.

The EPA proposes not to change the "no detectable emissions" requirement for pumps and valves complying with the alternative standards for process unit equipment affected facilities. The following paragraphs discuss the rationale for the proposed changes relating to NIE for CVSs, covers, and self-contained pneumatic controllers.

The EPA carefully considered the petitioners' concerns regarding emissions and defects from CVSs, covers, and process controllers and re-evaluated those requirements in the March 2024 Final Rule. The provisions for the CVS and cover intend for the control device (or process) to capture and route emissions generated at the emissions source, such as a storage vessel or compressor, thereby ensuring achievement of the underlying standard of performance for the emissions source. The EPA has seen, through implementation of the NSPS, that inadequate sizing of the CVS and cover (notably on storage vessels subject to the March 2024 Final rule) can result in the inability to accommodate all emissions, leading to over-pressurization events. An example includes liquid flowing from a separator to the storage vessel.[198] These over-pressurization events can result in actuations of pressure-relief devices which route emissions directly to the atmosphere. In this way, the pressure-relief device routes only some emissions to the control device, so the facility fails to meet the underlying emissions standard. Therefore, the EPA continues to believe that CVS and covers must meet robust design requirements, ensured by adequate ongoing monitoring.

As discussed previously, after reviewing the comments and examples provided by the petitioners, the EPA believes that even under the best scenarios, components on the

[198] *See e.g.*, *US and New Mexico Environment Department v. Mewbourne Oil Company*. https://www.justice.gov/enrd/consent-decree/file/1592561/dl?inline.

CVS and cover may have wear and tear from the environment and emissions may often be beyond the control of the operator, making them similar to other fugitive emissions sources which allow for routine monitoring and repair without subjecting a source to an immediate deviation when emissions are detected. Similarly, even with properly designed gasket materials, which include weighted mechanisms and withstand weather conditions and exposure to the composition of the fluid in the storage vessel, dirt and debris can affect the seating and seal of covers such that emissions may occur. The EPA also supports new detection methodologies and voluntary emissions detection efforts and recognizes that a NIE requirement which subjects a source to immediate violations from the detection of emissions may be counter to the Agency's goals of incentivizing the use of advanced technology. For these reasons, the EPA believes that making changes to the March 2024 Final Rule's requirements would still enable owners, operators, and the Agency to identify design flaws in covers and CVSs while allowing for flexibility in repairing emissions and defects related to normal wear and tear without subjecting the source to immediate non-compliance.

To accommodate these changes, the EPA re-evaluated the current criteria in the March 2024 Final Rule, which requires that the source "design and operate" the CVS or cover with NIE (as determined by OGI, AVO, or EPA Method 21).[199] The current provisions at 40 CFR 60.5411b and 60.5411c also require that the CVS capture and route all emissions to the control device (or process, when applicable) and for the cover to form a continuous impermeable barrier over the entire surface, with all openings closed except for certain process purposes. As discussed previously, the EPA proposes no changes to these design criteria. However, in enabling a leak detection and repair paradigm for emissions and defects related to normal wear and tear, the current criteria at 40 CFR

[199] 89 FR 16986 (March 8, 2024). *See* discussion where the EPA states that "[t]he NIE standard reflects this compliance assurance and demonstration requirement and, for the reason explained above, is an emission limitation of zero emissions, to be demonstrated by OGI, EPA Method 21, or AVO inspection."

60.5411b(a)(3) and (b)(4) and 60.5411c(a)(3) and (b)(4) to design with NIE may appear to conflict. That is, a design requirement "to capture **all** emissions" (emphasis added) is not the same as a design requirement which allows for leaks to occur (even if repairs are made). Accordingly, the EPA proposes to delete the requirement that the CVS and cover be "designed" to operate with NIE. In doing so, the EPA proposes a clear design requirement and a clear operational requirement. However, these requirements are not entirely independent of one another because – like with all monitoring – leak detection inspections provide evidence of the underlying performance of a system. Similarly, in this case, the design of the CVS or cover impacts its proper operation. Therefore, the design and operational requirements are linked for compliance and enforcement purposes. To address this interplay, the EPA proposes changes to the "no identifiable emissions test methods and procedures" in 40 CFR 60.5416b and 60.5416c to establish how the inspection and repair program ensures continuous compliance with both the design requirement and the operational requirement.

Specifically, the EPA proposes that covers and CVSs on well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facilities used to comply with the requirements to route to a process or to control, as applicable, should be monitored for emissions and defects and those emissions and defects related normal wear and tear be repaired upon identification or within a short timeline. The EPA recognizes that a short timeline of 24 hours, while sufficient for some companies to make routine maintenance fixes such as tightening, cleaning, or lubricating equipment, might pose challenges for other companies. Therefore, the EPA requests comment on all aspects of this proposed timeline, including suggested alternative timelines and supporting rationales. (Question III.6a) Further, the EPA believes that fixes which take longer than 24 hours could be indicative of a larger problem, such as a design flaw, and potentially signal a deviation of

the design requirements. Deviations suggest potential violations with the design requirement, but they are not automatically considered a violation. Consistent with the current requirements, owners and operators must record and report a description of the emissions or defect, each attempt to repair the emissions or defect, each corrective action taken to repair the defect, and the date of repair completion. The EPA will use this information, and/or other credible evidence or inspections, to determine whether a violation of the design requirement has occurred.[200]

The second proposed change to the current provisions recognizes that in addition to requirements to design the CVS and cover to capture and route all emissions to the control device, there is an ongoing operational requirement to operate with NIE. Compliance with the operational requirement includes a proposed leak detection and repair program. While the 24-hour repair timeline also applies, sources may also demonstrate compliance with the operational requirement by making repairs on a longer timeframe. For the reasons discussed above, the EPA believes that defects which require longer than 24 hours to repair indicate a design flaw. However, the EPA still believes there should still be a pathway towards compliance for the operational requirements. Therefore, a source which cannot repair within 24 hours may still make repairs under the current timeline of "as soon as practicable," but no later than 5 days for the first attempt at repair and 30 days for the final repair (counted from the detection of the emissions or defect). Sources which comply with these operational requirement timelines may also place equipment on delay of repair (DOR) for valid reasons, as currently provided in the rule. Therefore, the EPA is not proposing to change the current DOR provisions for the 5/30 day repair timelines. As discussed previously, the EPA proposes that a deviation of the design requirement occurs when a facility detects emissions and cannot complete

[200] 87 FR 74805 (December 6, 2022). *See* discussion where the EPA previously took the position that such identified emissions were violation of the NIE emissions limit.

repair in a quick and timely (*i.e.*, 24 hours) manner. The EPA proposes that deviations of the requirement to operate with NIE occur when a facility detects emissions using the selected method, but repairs fail to occur within 5/30 days and the DOR provisions do not apply.

In addition to deviations of the design requirement for repairs which cannot be made in 24 hours, the EPA proposes an investigative analysis for chronic leakers to further synchronize the design and operational requirements. The EPA believes that continued detection of emissions or defects from the same CVS or cover indicates failures of the system due to design, operation, maintenance, failure to adequately repair, or other causes. For this reason, the EPA proposes that after the same CVS or cover experiences emissions or defects three or more times in a rolling calendar year, the facility must perform an investigative analysis. The EPA proposes this threshold because it represents a reasonable indicator that an underlying design, operational, or maintenance issue exists. A first leak occurrence can often be reasonably attributed to normal wear and tear. A second emission occurrence may signal a developing issue but could still reasonably be attributed to normal wear and tear. However, a third emission occurrence involving the same cover or CVS would strongly signal a larger issue that warrants a formal resolution and potentially enforcement, because the design and operational ability of the CVS to route all emissions to the control device impacts the 95 percent control BSER for the underlying emission source. The EPA proposes that the facility conduct an investigative analysis within 10 days after detecting the emissions or defect for the third time in a rolling calendar year, and the owner or operator must determine the cause of the defect. The EPA proposes that if the design caused the emissions or defect, this constitutes a deviation of the design requirement; if a failure to adequately repair the source of the emissions or defect during prior attempts caused the emissions or defect, this constitutes a deviation of the repair requirements; and if due to operation,

maintenance, or other cause(s), this constitutes a deviation of the operational requirements of the rule. Following the analysis, the owner or operator must determine what corrective actions are necessary to ensure the design, operational, repair, or other requirements are met and must implement the corrective actions. For design flaws, the EPA proposes that the corrective actions must be made no later than 90 days after completion of the investigative analysis and for other flaws, the Agency proposes that the facility must complete corrective actions no later than 30 days after completion of the investigative analysis. This repair timeline is consistent with already established repair timeline requirements for fugitive emissions and covers and CVSs.[201, 202]

The March 2024 Final Rule has minimal requirements for records and reports for emissions or defects, due in part to the fact that the EPA believed that the burden of immediate and continued non-compliance with the NIE requirement (until repair) incentivized timely repairs. With the proposed changes to NIE, the NIE monitoring program would more closely resemble traditional leak detection and repair requirements (including in the March 2024 Final Rule), which requires more robust repair and resurvey criteria and recordkeeping and reporting requirements. For this reason, the EPA also proposes the following changes: a definition of what constitutes a "repaired" CVS and cover; specific resurvey requirements to be conducted after repair; and identification of leaking components (which are not repaired during the inspection or within 24 hours of when the leak or defect is initially found). Specifically, the EPA proposes the following definition of "repaired" for covers and CVSs:[203]

> For the purposes of covers, closed vent systems, and self-contained natural gas-driven process controller affected facilities, that the cover, closed vent systems, or self-contained natural gas-driven process controller is adjusted, replaced, or otherwise altered, in order to eliminate defects or emissions detected by AVO when inspections are conducted by AVO;

---

[201] 89 FR 17157 (March 8, 2024)
[202] 89 FR 17102 (March 8, 2024)
[203] For reasons discussed later in this section, the EPA proposes that the same requirements that apply to covers and CVSs also apply to self-contained natural gas-driven process controller affected facilities.

> eliminate emissions imaged with an OGI camera when inspections are conducted with OGI; eliminate emissions with an instrument reading of 500 ppmv above background or greater, as determined by Method 21 of appendix A-7 of this part when inspections are conducted with Method 21; and is re-monitored in accordance with the provisions of §60.5416b(a) and (b), to verify that emissions and defects are no longer detected. Emissions imaged by OGI may be re-monitored with OGI or Method 21 of appendix A-7. Emissions detected by Method 21 of appendix A-7 may be re-monitored with OGI or Method 21. Emissions or defects detected by AVO may be re-monitored by AVO, OGI, or Method 21 of appendix A-7.

The EPA believes that a definition of "repaired" aligns the CVS and cover requirements with those for fugitive emissions components affected facilities and process unit equipment affected facilities and provides clear expectations for compliance with the requirement to "repair" components found to be leaking during initial and periodic inspections. Within the definition of "repaired" and the repair requirements for CVSs and covers, the EPA also believes that components require resurveying to ensure the repair's effectiveness. The proposed resurvey requirements offer flexibility to use any method (*e.g.*, OGI, EPA Method 21, or AVO) of detection for leaks or defects detected by AVO, and either EPA Method 21 or OGI for leaks and defects detected by either. This proposed requirement also is consistent with the repair requirements for fugitive emissions components affected facilities and process unit equipment affected facilities. In addition, if the facility does not complete the repair during the inspection in which the facility initially finds a leak or defect, the EPA proposes to require identification methods of leaks or defects. This change ensures that leaking components can be tracked and identified for repair at a later date. Identification methods include a digital photograph, identification on a process and flow instrumentation diagram, or tagging. These requirements also ensure consistency with the requirements for fugitive emissions components affected facilities and process unit equipment affected facilities. The EPA proposes to include records and reports for these additional requirements.

The EPA proposes similar changes to require an investigative analysis when emissions are detected through periodic screenings under the alternative technology

standards for covers and CVSs. Because of additional time required to receive results of the periodic screenings, as is with inspections conducted using AVO, OGI, or EPA Method 21, the shortened timelines for repair will begin once the results of the alternative technology monitoring are available. Also, while periodic monitoring using alternative technology requires an investigative analysis, the investigative analysis in 40 CFR 60.5398b and 60.5398c does not provide a timeline for implementing changes when the leaks are identified, which could result in ongoing emissions or defects from the same covers and CVSs. For this reason, the EPA proposes to require the investigative analysis proposed in 40 CFR 60.5416b(b)(10) and 60.5416c(b)(10) when conducting periodic monitoring of covers and CVSs using alternative technologies. The EPA proposes not to apply the proposed investigative analysis in 40 CFR 60.5416b and 60.54165c to covers and CVS inspections conducted with continuous monitoring using alternative technologies because the continuous monitoring requirements of 40 CFR 60.5398b and 60.5398c already provide for continuous improvement to reduce emissions below the action level.

With the proposed changes to the NIE operational requirements to include repair and investigative analysis requirements, the EPA proposes changes to the definition of NIE in 40 CFR 60.5430b and 60.5430c. The EPA proposes that operating with NIE means operating with less than 500 ppm above background when monitoring with EPA Method 21, operating with no emissions detected by AVO when monitoring with AVO, or operating with no emissions imaged when monitoring with OGI. The EPA also proposes that NIE requires imaging of emissions using one of the methods (AVO, OGI, or EPA Method 21 of appendix A) but requires repairs according to the proposed timeline or are placed on DOR, when applicable.

Similarly, a self-contained process controller, defined at 40 CFR 60.5430b and 60.5430c as “a natural gas-driven process controller that releases gas into the downstream

piping and not to the atmosphere, resulting in zero methane and VOC emissions," exhibit the same presence of potential sources of normal wear and tear emissions on the "downstream piping." Therefore, the EPA believes that these sources also should be allowed the benefit of an attempt at quick repair of emissions or defects before a deviation occurs. Self-contained process controllers already reference the NIE requirements at 40 CFR 60.5416b(b) and 60.5416c(b). The EPA proposes that the requirements for repair and investigative analysis, which are currently proposed for CVSs and covers in 40 CFR 60.5416b and 60.5416c, also apply for self-contained process controllers. In addition, to provide a citation for deviations of the design requirement for the purposes of self-contained process controllers which do not timely repair, the EPA proposes to add a design requirement to the standards for self-contained process controllers. The definition of self-contained process controller at 40 CFR 60.5430b and 60.5430c currently includes a design requirement and the EPA proposes to include the requirement to design the self-contained process controller so that it "releases gas into the downstream piping and not to the atmosphere, resulting in zero methane and VOC emissions" at 40 CFR 60.5390b(a)(2) and 60.5394c(a)(2).

Finally, regarding the "no detectable emissions" requirement for pumps and valves under the alternative standards for process unit equipment affected facilities at 40 CFR 60.5401b(b)(3) and (f)(3) and 60.5401c(b)(3) and (f)(3), the EPA proposes not to change this requirement to a work practice standard. When establishing standards for equipment leaks from onshore natural gas processing plants, NSPS KKK[204] referenced the requirements in NSPS VV. When the EPA proposed[205] and promulgated[206] NSPS OOOO, the requirements for equipment leaks from onshore natural gas processing plants

[204] 49 FR 22598 (May 30, 1984).
[205] 76 FR 52738 (August 23, 2011).
[206] 77 FR 49490 (August 16, 2012).

were updated to reflect the requirements in NSPS VVa[207] and were included in the final standards for NSPS OOOO and carried forward into NSPS OOOOa.

In the March 2024 Final Rule, the EPA finalized the results of the technology review of the LDAR standards at natural gas processing plants to require a bimonthly OGI LDAR program following appendix K. As explained in the November 2021 proposal, the EPA believes that a Method 21 monitoring program based on the requirements of NSPS VVa achieves similar emission reductions to the bimonthly OGI LDAR program.[208] Therefore, in the March 2024 Final Rule, the EPA also finalized a Method 21-based LDAR program based on the requirements of NSPS VVa as an alternative to bimonthly OGI surveys. NSPS VVa included the same standards as NSPS VV for pumps and valves, which are designated to operate with "no detectable emissions." These standards were proposed as "leakless" equipment alternatives to a leak detection and repair (*i.e.*, work practice) program. The EPA stated in the preamble to the proposed rule for NSPS VV that "sealless pumps are at least equivalent to dual mechanical seals with barrier fluid degassing vents connected to control devices in controlling fugitive emissions. Therefore, the proposed standards allow them for owners/operators who wish to use them. Sealless pumps would be required to operate under a "no detectable emission" limit as discussed in *Leakless Equipment* in this section."[209] For valves, the EPA proposed in NSPS VV that "[e]quipment specifications considered for valves were diaphragm valves and bellows-sealed valves…the use of these valves would be at least equivalent [to Regulatory Alternative IV] because they eliminate leakage of VOC.[210] The use of such valves is allowed as an alternative. These valves would be required to operate under a "no detectable emission" limit as discussed in the

[207] 72 FR 64883 (November 16, 2007).
[208] 86 FR 63233 (November 15, 2021).
[209] 46 FR 1144 (January 5, 1981).
[210] 46 FR 1141 (January 5, 1981). Regulatory Alternative IV was monitoring and equipment specifications.

Leakless Equipment discussion of this section."[211] The *Leakless Equipment* section of the proposal for NSPS VV stated that "the use of this equipment achieves excellent control (100 percent) of fugitive emissions" and that the "use of leakless equipment is clearly equivalent if not better than the proposed standards for pumps, compressors, and valves and the proposed standards would allow the use of such equipment as an alternative to the required practices. The leakless equipment would be required to be operated with "no detectable emissions" at all times when it is in service."[212] The requirements at 40 CFR 60.482-2a(e) and 60.482-7a(f) require annual inspections for compliance with the NDE requirement and do not offer the opportunity for leak detection *and repair* to ensure compliance.

Because NSPS OOOOb and EG OOOOc neither proposed nor finalized different requirements from NSPS VV, and then VVa, for pumps and valves complying with NDE, the requirement in NSPS OOOOb and EG OOOOc is that the pumps and valves must operate with NDE at all times. In addition to the NDE operational requirements, an NDE pump must be designed such that it has no externally actuated shaft penetrating the pump house, and NDE valve must have no externally actuated mechanism in contact with the process fluid. These equipment design requirements ensure that compliance with an NDE requirement is feasible. The EPA notes that a source is not required to use the NDE pump or valve requirements and may instead comply with monthly EPA Method 21 monitoring and weekly visual inspections (for pumps) or quarterly EPA Method 21 monitoring (for valves) which do allow for leak detection and repair to ensure compliance.

The EPA solicits comment on all aspects of the proposed changes to the CVS requirements. (Question III.6b) The EPA is specifically taking comment on whether these changes fully address concerns raised by petitioners regarding the CVS monitoring and

---

[211] 46 FR 1144 (January 5, 1981).
[212] 46 FR 1148 (January 5, 1981).

repair requirements not recognizing the unique challenges the oil and gas industry, specifically, because of the fact that facilities have many remote sites where rapid repair may be significantly more challenging than facilities such as refineries or chemical plants that are staffed twenty four hours a day. Petitioners expressed concerns that the current NIE requirements create perverse incentives that discourage the use of advanced detection technologies or proactive voluntary monitoring. The Agency is also taking comment on the impacts that these proposed provisions may have on willingness to use alternative monitoring approaches. (Question III.6c)

More specifically, the EPA solicits comment on petitioners' suggestion that the NIE standard for CVSs should be replaced with an LDAR work practice approach more consistent with the framework applied to fugitive emissions components. The EPA takes comment on petitioners' arguments that in many cases the components of a CVS (valves, pipes and connectors etc.) are identical to the components covered by the fugitive program. (Question III.6d)

The EPA also solicits comment on what specifically such an approach (similar to the LDAR work practice standard) might entail. In particular, the Agency takes comment on whether an LDAR approach could be designed with additional safeguards to account for the fact that unlike other components of the existing LDAR program, CVS are integral to the ability to control any emissions that have been captured and are being routed to the control device through the CVS (Question III.6e).

The EPA further solicits comment on the extent to which the inadequate or undersized tank design is the underlying cause of emissions from CVS on storage vessels and whether the proposed NIE requirements address the challenges the industry faces. (Question III.6f) Additionally, are there better systematic approaches to identifying all under-designed CVS than a requirement to operate CVS with NIE? The Agency is considering whether an inability to repair within 24 hours is an appropriate way to

identify systems with design flaws, and what the appropriate criteria and requirements are to address chronic leakers under an NIE or another approach. (Question III.6g)

H. Control Devices

1. Background

In the March 2024 Final Rule, the EPA finalized various requirements regarding control devices. Since the publication of this rulemaking, reconsideration petitioners have raised several issues on the March 2024 Final Rule requirements for control devices.[213] In this action, the EPA proposes changes to the March 2024 Final Rule related to flame monitoring data deviations, control device alerts, visible emissions test conditions for fugitive emissions, control devices used on a temporary basis, temporary process controllers used on temporary control devices, and control device categories. In addition, the EPA is not proposing changes but is instead soliciting comment on continuous burning pilot flames, backup control devices, and standalone temporary process controllers.

a. Continuous Burning Pilot Flame

Background. Petitioners requested that the EPA revise the continuous burning pilot or combustion flame requirement from "at all times of operation" to "at all times when emissions from affected facilities are routed to the control device."[214] Petitioners also requested that the continuous pilot requirements exclude times when a site is not operating (*e.g.*, an emergency shutdown) and the pilot or combustion flame is also shut down.

Petitioners explained that pilot flames go out for a variety of reasons and that the suggested revised language of "at all times when emissions from affected facilities are

---

[213] API & AXPC (2024a); Environmental Integrity Project (EIP), et al. (2024). Letter to Michael S. Regan, EPA Administrator, from EIP, et al. Re: Petition for Reconsideration of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Final Rule, 89 Fed. Reg. 16,820. May 7, 2024; and API & AXPC (2024b).

[214] API & AXPC (2024b).

routed to the control device" allows operators to maintain compliance by temporarily isolating the affected facility from the control device while addressing a known pilot outage situation. In addition, the petitioners claimed that this flexibility reduces the need for a site shutdown to address a pilot outage, which may result in greater emissions than a pilot flame outage.

Petitioners further asserted that maintaining a continuous pilot flame creates an environmental disbenefit by burning more fuel and generating unnecessary emissions when no vent streams are routed to the control device. As an alternative, the petitioners suggested the use of an automatic ignition system which can light a pilot or combustion flame only when needed to control emissions from affected sources. Petitioners recommended that the EPA revise the continuous pilot requirements to clearly exclude times when a site is not operating (*e.g.*, an emergency shutdown). Petitioners explained that, during these instances, the combustion control device also has to shut down. Therefore, the combustion control device may not have a pilot or combustion flame due to safety considerations or have a lack of fuel gas where field gas is used as the pilot.

Summary of Comment Solicitation. The March 2024 Final Rule, past iterations of the NSPS (OOOO and OOOOa), and the Part 60 General Provisions (40 CFR 60.18(c)) necessitate that flares and ECDs have a combustion (*i.e.*, pilot) flame present at "all times of operation." Currently, the EPA understands that owners and operators primarily use natural gas from their production streams to fuel the continuously lit pilot flames. At sites without sufficient natural gas, or sites with a lot of sour gas in their streams, owners and operators instead rely on propane not from their production streams to fuel pilot flames. Some reconsideration petitioners contend that the usage of propane in these scenarios contributes to unnecessary emissions, particularly when nothing is routed to the control device.[215] However, the EPA has not received information on the incidence of sites that

[215] EIP, et al. (2024); and API & AXPC (2024b).

are unable to route on-site gas to fuel the continuous pilot flame and whether the additional emissions from this process are substantial. Therefore, the EPA has not been able to quantify the additional emissions emitted from the usage of propane in these scenarios.

While petitioners want the EPA to change the provision from at "all times of operation" to at "all times when emissions are routed to the control device," at this time the EPA is maintaining the provision as stated in the March 2024 Final Rule. The EPA is not proposing any changes to these requirements in this action. The EPA has opined in previous rulemakings on the reliability and performance of automatic igniter pilots.[216] In short, the EPA has not received sufficient information that suggests that automatic igniters perform comparably to continuously lit pilots. Put another way, the EPA's assessment of automatic igniter pilots is that they often fail and continue to have reliability issues, which results in uncontrolled venting when emissions are routed to the control device. Reasons for this insufficiency, compared to continuously lit pilot flames, include the rapid degradation of automatic igniters over time, the instability in the flame caused by the intermittent nature of the device, the high frequency of reignition failures, and the delays between ignition and the point at which streams are routed to the control devices. A comprehensive study of combustion-based control devices at oil and gas facilities corroborates these findings.[217] More specifically, a review of those results indicates that the incidence of unlit flares exceeded expected values, even for flares equipped with automatic flame re-igniter technology. Thus, relying on automatic igniter pilot flames in lieu of more reliable technology, such as continuously lit pilot flames, could increase the rate of unlit flares and lead to dramatically higher emissions of

---

[216] U.S. EPA. (2023b). Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule (86 FR 63110, November 15, 2021; 87 FR 74702, December 6, 2022). *See* Response II-17-2.
[217] Genevieve Plant et al., Inefficient and unlit natural gas flares both emit large quantities of methane. Science, 377,1566-1571 (2022).

methane and VOC from uncontrolled venting. Some States do allow for the usage of automatic igniters in their provisions, but the provisions are typically narrow in scope. For example, New Mexico allows for ECDs to use automatic igniters during start-up procedures, or when reigniting the continuous pilot flame after it went out.[218] Similarly, in the March 2024 Final Rule, the EPA allowed automatic igniter pilots only to reignite the continuous pilot flame, not to replace it outright.[219]

Since the EPA has not received any recent information indicating that the technology or reliability of these automatic igniter pilot has changed and improved, in this proposed rule the EPA solicits comment on the reliability, efficacy, and overall performance of automatic igniter pilot technology to ascertain if the devices perform comparably to continuously lit pilot flames. Moreover, the EPA solicits comment on the number of sites that have to use additional fuel (*i.e.*, not from their production streams) to sustain a continuous pilot flame. EPA also solicits comment on the emissions and costs associated with maintaining a continuous pilot light when no emissions from the unit are being sent to the flare (whether the fuel used for the pilot light is an additional fuel (such as propane) or from the sites production stream (*e.g.*, natural gas)). (Question III.7a)

b. Flame Monitoring Data Deviations

Background. The March 2024 Final Rule requires owners and operators to continuously monitor that a combustion flame is lit at all times of operation in their combustion-based control device(s). The presence of a combustion flame is measured parametrically by a thermocouple that records the temperature of the device. The thermocouple system, in turn, must record a value at least once every 5 minutes of operation. Currently, any lack of (*i.e.*, failure to collect) monitoring data not directly

---

[218] New Mexico Admin Code 20.2.50.

[219] U.S. EPA. (2023b). Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule (86 FR 63110, November 15, 2021; 87 FR 74702, December 6, 2022). *See* Responses II-17-1, II-17-2, and II-17-22.

related to a malfunction of the combustion-based control device(s) results in a deviation.[220]

Petitioners requested the EPA revise these provisions so that a lack of control device monitoring data does not automatically constitute a deviation.[221] Petitioners have noted that their data acquisition and storage systems sometimes malfunction independently of the control device. As such, petitioners contend that a lack of monitoring data (*e.g.*, a gap in the data when the monitoring equipment was not working properly due to a telecommunications loss rather than a process failure) should not be considered a deviation, provided that other available information (*i.e.*, other data which was recorded) indicates the presence of a pilot flame. For instance, if a combustion-based control device with no automatic igniter pilot installed had high temperature readings that indicate a lit flame before and after the lapse in data recording, and the lapse in data recording was relatively short, that would provide a reasonable assurance that the control device itself properly operated during the lapse in data recording.

Summary of Proposed Changes and Rationale. Under the March 2024 Final Rule, any lack of monitoring data not directly related to a malfunction of the combustion-based control device results in a deviation. Here, the EPA proposes to revise the March 2024 Rule to clarify that time-limited gaps in pilot or combustion flame monitoring data do not automatically constitute a deviation, if other available documented information indicates a pilot flame's presence during the data gap, coupled with a confirmation that the data gap was due to data collection equipment problems. Consistent with the current monitor availability requirements specified throughout NSPS OOOOb and EG OOOOc, a deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day. Under this proposed rule, the 75 percent monitor availability

[220] 40 CFR 60.5415b(f)(1)(vi) and 60.5415b(f)(1)(xi)(E).
[221] EIP, et al. (2024); and API & AXPC. (2024b).

requirement would apply to the combination of both the primary monitoring data and other available documented information, for those periods where there is a gap in the primary monitoring data. Specifically, the EPA proposes to make changes to NSPS OOOOb (40 CFR 60.5417b(g)(6)(iii) and 60.5417b(i)(6)(v)) and EG OOOOc (40 CFR 60.5417c(g)(6)(iii) and 60.5417c(i)(6)(v)).

The EPA recognizes the petitioner's concerns that gaps in (or the absence of) flame monitoring data may result from interruptions in recordings by data acquisition and storage systems rather than from an actual loss of flame or improper operation. As a result, the EPA proposes to consider additional available documented information, such as combustion-based control device data from before and after the lapse that indicates a pilot flame's presence during the data gap, before determining whether a deviation occurred. By considering this additional information, the EPA provides flexibility for industry to meet the monitoring requirements while still maintaining accountability for ensuring continuous pilot flames. If other available documented information indicates a pilot flame's presence during the data gap, the EPA clarifies that a deviation has not occurred. With this proposed change, the EPA believes that allowing operators to demonstrate, through supplemental documentation, that the data gap did not stem from an unlit flame would be responsive to petitioners' concerns.

c. Control Device Alerts

Background. The March 2024 Final Rule requires owners and operators to report any instances in which a pilot or combustion flame becomes unlit to the "nearest" control room.[222] In a recent letter the EPA received from some industry stakeholders, petitioners suggest removing or revising this requirement.[223] Petitioners argued that the installation and maintenance of reliable data acquisition and storage systems are particularly difficult

[222] 89 FR 17089 (March 8, 2024).
[223] 89 FR 17089 (March 8, 2024). EIP, et al. (2024); and API & AXPC (2024b).

at remote sites, largely due to the cost associated with installing new telecommunications to automate alarm systems. Furthermore, petitioners claimed that implementing these telecommunications upgrades often requires extensive permits and approvals from various federal agencies.[224] For sites that have access to telecommunications, petitioners argued that the provisions as written are untenable. Specifically, petitioners contended that the requirement to notify the nearest control room unnecessarily restricts facilities as the nearest control room (or closest facility) might not be best suited to address the unlit control device. Petitioners claimed that operators often rely on centralized dispatch control facilities stationed sometimes miles away (or in another state) from the location to respond to such issues.

Summary of Proposed Changes and Rationale. In the current rule, an unlit pilot or combustion flame requires that an alert be sent to the nearest control room. The EPA proposes to revise the requirement to allow owners or operators to send these alerts to either the nearest control room or to a centralized control room during instances of an unlit pilot or combustion flame. Specifically, the EPA proposes to make changes to NSPS OOOOb (40 CFR 60.5412b(a)(1)(viii), 40 CFR 60.5412b(a)(3)(viii), 40 CFR 60.5413b(e)(2), 40 CFR 60.5415b(f)(1)(vii)(A)(*1*), and 40 CFR 60.5417b(d)(8)(i)) and EG OOOOc (40 CFR 60.5412c(a)(1)(viii), 40 CFR 60.5412c(a)(3)(vii), 40 CFR 60.5413c(e)(2), 40 CFR 60.5415c(e)(1)(vii)(A)(*1*), and 40 CFR 60.5417c(d)(8)(i)).

The EPA considers that a centralized control room (or control center) equipped with reliable telecommunications to collect and store data works as an acceptable alternative to the March 2024 Final Rule requirements to report lapses in pilot or combustion flame lighting to the nearest control room, even if that control room is located further away from the combustion device because that centralized control room may be better equipped and situated to respond to the unlit flame in an efficient and

[224] *e.g.,* Federal Trade Commission, Federal Aviation Administration, Bureau of Land Management.

timely manner. Take, for example, a hypothetical situation where the nearest control room is 3 miles from the site (as measured on a map in a direct line "as the crow flies") and a centralized control room is 50 miles from the site. The EPA finds no reason to limit the alert to the control room at 3 miles and prohibit the alert from instead going to the control room at 50 miles.

The EPA originally included the requirement for sending alerts when the pilot or combustion flame becomes unlit to the nearest control center because of its proximity to the site. When equipped with proper telecommunications equipment, the nearest control room (or control center) remains an effective option, and the EPA will continue to allow it as one of the locations to fulfill this requirement. However, the EPA acknowledges that sites lacking the ability to address the unlit flame from their nearest control room currently rely on resources from a centralized control room, regardless of where the owner or operator first sends the alert. Since the response time should remain unchanged under these circumstances, allowing owners and operators to directly send alerts to a centralized control room should not negatively impact the time taken to address the issue. In addition, the EPA agrees with petitioners that adding certain telecommunications equipment to sites in remote locations could have additional installation costs and may require a burdensome permitting process. Allowing operators the option to send the alert to an established centralized control room would provide flexibility and reduce burden on industry, while maintaining the effectiveness of the alert systems at the same level as prescribed in the March 2024 Final Rule.

d. EPA Method 22 "As Found" Conditions

Background. The March 2024 Final Rule requires operators to conduct 15-minute EPA Method 22 visible emissions observations (*i.e.*, a determination of whether fugitive visual emissions occur) at least once each calendar month for various operating scenarios

while each affected combustion control device operates.[225] Petitioners requested greater flexibility for operators to conduct EPA Method 22 (40 CFR Part 60, Appendix A-7) observations.[226] Petitioners explained that due to substantial investment and ongoing efforts to maximize gas recovery for sales prior to liquids entering storage vessels, routing to a combustion control device occurs only intermittently. As a result, they argued that any EPA Method 22 observation conducted in the "as-found" condition of the combustion control device should count towards satisfying the monthly requirement. Otherwise, the petitioners cautioned that requiring operators to conduct EPA Method 22 observations only when combustion control devices actively receive emissions from affected and designated facilities would make compliance infeasible or force operators to intentionally flare.

Summary of Proposed Changes and Rationale. The EPA proposes to add a 24-operating hour "grace period" beyond each calendar month test period to allow operators to complete the monthly EPA Method 22 observation under normal operating conditions for each affected source. Specifically, the EPA proposes changes to NSPS OOOOb (40 CFR 60.5412b(a)(1)(ix), 40 CFR 60.5413b(e)(3), 40 CFR 60.5415b(f)(1)(vii)(A)(*2*), and 40 CFR 60.5417b(d)(8)(v)), and EG OOOOc (40 CFR 60.5412c(a)(1)(ix), 40 CFR 60.5413c(e)(3), 40 CFR 60.5415c(e)(1)(vii)(A)(*2*), and 40 CFR 60.5417c(d)(8)(v)).

The EPA recognizes that, due to various circumstances, operators may be unable to perform the required monthly EPA Method 22 observation. However, the EPA finds that performing a monthly EPA Method 22 test under "as found" conditions would not always comprehensively represent the applicable source's operation. For example, if the source is not operating at the time a facility performs an "as found" EPA Method 22 test, the EPA Method 22 results would indicate no presence of fugitive visual emissions.

---

[225] 89 FR 17095 (March 8, 2024).
[226] API & AXPC (2024b).

However, any such observation in that situation would stem from the source not being in operation, as opposed to confirming that the source operated without emitting fugitive visible emissions. Put another way, in order to determine if the combustion device is leaking gas one needs to observe the device with gas flowing through it. Observing no leaks when no gas is flowing in the device does not necessarily mean that the device is operating properly. By way of analogy, a plumber needs to observe a drainpipe with water flowing through it in order to determine if the drainpipe is leaking. If a plumber looks at a drainpipe while no water is flowing through it and sees no leaks, that does not necessarily mean the pipe is sound because it could leak as soon as you run water through the pipe due to a problem that was not otherwise easily observable without water running through the pipe.

With the proposed 24-operating-hours (as opposed to clock-hours) grace period being allowed after the conclusion of each calendar month in order to perform the monthly Method 22 observation, the EPA believes that these changes provide a reasonable accommodation to account for intermittent process flow, unpredictable operational schedules, and the time needed for staff to reach the site to perform the test.[227] The EPA further notes that if a facility utilizes the proposed 24 operating hours grace period, the facility cannot use that particular EPA Method 22 observation for the calendar month in which the "grace period test" occurred. That is, the "grace period test" would apply to the month with the missed "original" EPA Method 22 test, and a standard EPA Method 22 test would still need to occur in the month that the "grace period test" occurred (with the two observations separated by at least 15 days as currently prescribed by the rule). The EPA solicits comment on whether a 24-operating-hours grace period suffices to accommodate the potential situations raised by petitioners, particularly

[227] For example, if a Method 22 test could not be completed in July, the 24-hour grace period would start with Operating Hour 1 in August.

considering the frequency of intermittent venting or accessibility of some sites. (Question III.7b)

e. Temporary Control Devices and Backup Control Devices

Background. Under the March 2024 Final Rule, the EPA regulates temporary and backup equipment in the same manner as permanently installed equipment that operates on a regular basis. Petitioners requested that the EPA exempt temporary control devices (TCDs) from the monitoring and performance testing requirements of the March 2024 Final Rule, because, given the short duration of their use, compliance is impracticable, if not impossible. [228] One petitioner provided liquids unloading as an example, noting that the ongoing compliance assurance requirements related to both a CVS and control device do not appropriately apply to liquids unloading operations. Petitioners state that because liquids unloading events occur intermittently, many of the required monitoring would take place while no liquids unloading activities occur.[229] Therefore, the petitioner asserted that the EPA should authorize the use of a temporary flare or portable control device to handle the emissions from liquids unloading events without stringent monitoring and recording requirements. Due to the temporary nature of these activities, the petitioner requested that the EPA mimic the requirements of control devices utilized for well completion affected facilities for any intermittent activities (*e.g.*, emergencies, routine maintenance, liquids unloading events, and blowdowns). In addition, petitioners expressed concerns regarding testing requirements for TCDs when the devices do not stay on-site long enough to meet the minimum testing durations. Petitioners used the 14-day NHV alternate sampling requirement as an example of an instance where the TCD may not remain on site long enough to meet the minimum testing duration.

[228] API & AXPC (2024b).
[229] API & AXPC (2024a).

Petitioners further asked the EPA to exempt backup control devices (BCDs) from monitoring and recordkeeping provisions. Petitioners defined BCDs as auxiliary and stationary control devices that are mostly used when a control device malfunctions or is out of service for maintenance. Because of their infrequent use, petitioners claimed difficulty in meeting prescribed testing and other compliance requirements. Petitioners asked the EPA to allow for exemptions up to 90 days per year per site for BCDs.

Summary of Proposed Changes and Rationale. Under the March 2024 Final Rule, temporary equipment is regulated in the same manner as permanently installed equipment that operates on a regular basis. The EPA agrees with the petitioner's assertion that TCDs should be exempted from some monitoring and performance testing requirements during intermittent activities, mainly due to the relatively short and unpredictable time the TCD could be on-site (which renders a permanently installed monitoring device such as a gas chromatograph or a 14-day sampling window infeasible for both sampling and scheduling purposes), coupled with the fact that these devices are typically rented from vendors not subject to the same air permit requirements as the facility itself. The EPA agrees that the rule's equal treatment of temporary and permanent devices creates practical burdens, because temporary devices (1) currently must maintain the same documentation, monitoring, and reporting as permanent devices, (2) are routinely moved, rented, or deployed quickly for short-term operational scenarios not conducive to stable monitoring, (3) often lack the integrated infrastructure and continuous monitoring systems of permanent units, and (4) must demonstrate destruction efficiency and proper operation under highly variable conditions and compressed timelines. These issues together explain why temporary control devices face disproportionate difficulty demonstrating compliance, even though the regulatory requirements themselves do not change with regards to temporary versus permanent control device use. Hence, the EPA

agrees with the petitioner's assertions on the need for additional flexibility to be able to use mobile or quickly installable equipment when necessary.

Currently, some States have already set a precedent and offer exemptions for TCDs, with the duration of the exemptions centering around 30 days per year per site. For instance, the State of Texas allows for 480 hours (20 days) of exemptions per year from monitoring and record keeping for temporary control devices.[230] Industry stakeholders noted that most intermittent activities get resolved within 30 days. Hence, when an owner or operator uses a TCD, it usually is not on site for more than 30 days. As described above, this short timeframe makes it difficult for the owners or operators who use the TCD to comply with the monitoring and performance testing requirements of the March 2024 Final Rule. Moreover, based on industry feedback, some emergencies or other unanticipated scenarios can necessitate the use of TCDs beyond 30 days.[231]

Therefore, the EPA proposes to exempt temporary control devices that are used for 30 operational days or less per site per year (on a 12-month rolling basis) from the NHV monitoring and performance testing requirements in the March 2024 final Rule. However, temporary control devices used for 30 operational days or less per site per year, on a 12-month rolling basis, must maintain certain records, including (1) performance certification documentation from the device manufacturer or rental vendor verifying that the flare can meet the required destruction efficiency of 95.0 percent for methane and VOC emissions, (2) make, model, and type of rental or temporary equipment (*e.g.,* trailer-mounted, skid-mounted, etc.), (3) location, date, and duration of operation of the device in hours, including start and stop time for each day of operation, (4) the volume of gas flared or vented, (5) documentation that the pilot flame is active at all times of operation of the device, (6) the

[230] TCEQ (2012). Oil and Gas Easy to Read 106.352: §106.352. Oil and Gas Handling and Production Facilities (Rev. 02/12). Table 8: Monitoring and Records Demonstrations (pp. 60–68). https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/og-easy-2012.pdf.
[231] API-AXPC TCD Meeting Notes (August 4, 2025).

specific reasons for the use of the temporary control device in lieu of capture or combustion, (7) the equipment rental agreement, and (8) documentation of whether or not a temporary process controller was used as part of the temporary control device configuration.

The EPA is also proposing that thereafter owners and operators can have an additional extension of the exemptions up to 60 additional operational days per site per year (on a 12-month rolling basis). For this additional extension period, the EPA proposes to require additional recordkeeping.[232] More specifically, for temporary control devices used for 90 operational days or less and greater than 30 operational days per site per year, on a 12-month rolling basis, the same recordkeeping requirements previously summarized would still apply, along with gas composition data (including the net heating value) from a single grab sample for every 30 days of operation and documentation of equipment inspections and maintenance activities, including those prescribed by the manufacturer of the temporary control device. After 90 operational days of use, the TCD would then be subject to the same requirements as a permanently installed device at the facility would be. These proposed changes would impact NSPS OOOOb (40 CFR 60.5413b(a), 40 CFR 60.5415b(f), 40 CFR 60.5417b(b), and 40 CFR 60.5420b(c)) and EG OOOOc (40 CFR 60.5413c(a), 40 CFR 60.5415c(e), 40 CFR 60.5417c(b), and 40 CFR 60.5420c(c)).

In this proposed rule, the EPA proposes to define temporary control devices as control devices that are either mobile (whether on wheels, trucks, railcars, barges, ships, *etc.*) or skid mounted. This definition is modeled after the definition set by the State of Texas for TCDs.[233] Based on information provided by reconsideration petitioners, the EPA concluded, for the purposes of this proposal, that TCDs and stationary control

---

[232] Under this provision, there would be no limit to the number of TCDs that could be used per site, provided that the total number of days does not exceed 90 operational days per year (*e.g.*, one TCD used for 90 days, ten TCDs used for 9 days each, *etc.*).

[233] TCEQ Control Device Requirement Charts for Oil and Gas Handling and Production Facilities. https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/og-easy-2012.pdf.

devices had no other functional differences other than the aforementioned criterion.[234] Therefore, the EPA finds the performance of TCDs at controlling emissions as comparable to the performance of stationary control devices. Put another way, TCDs must still comply with the requirement in the March 2024 final Rule to reduce emissions that are routed to the TCD by 95.0 percent. The EPA's proposed changes for TCDs only relate to certain monitoring provisions.

Summary of Comment Solicitation. The EPA acknowledges the petitioner's request to also exempt BCDs from the monitoring and performance testing provisions. While the EPA understands the need to exempt TCDs to address emergencies and other intermittent activities, the Agency has not received sufficient information to propose exempting BCDs. Specifically, the EPA lacks clarity on how BCDs differ from stationary control devices in a way that would warrant such a change. Moreover, the EPA understands that an air permit includes a BCD and lists BCDs as permitted equipment, along with the other permanent, stationary equipment and emission sources located at the facility. Unlike BCDs, the EPA understands that operators use TCDs on a temporary and situational ad hoc basis. Additionally, the EPA has not received sufficient information on the incidence of use or the number of BCDs across the industry.

Therefore, the EPA solicits comment on the use of BCDs, specifically on how BCDs differ from the permanently installed control devices operating at a given facility. The EPA additionally requests information on the incidence of use and the number of BCDs across the industry. The EPA also solicits comment on how to define BCDs, so as to not inadvertently incentivize their use over permanently installed control devices. (Question III.7c)

f. Temporary Process Controllers

---

[234] API (2025). Re: Request for Administrative Reconsideration of EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities" - NSPS OOOObc. September 12, 2025.

Background. Reconsideration petitioners highlighted that while permanent equipment runs routine production after flowback, oil and gas sites routinely rely on short-term equipment such as temporary process controllers (TPCs) to fulfill specific purposes during intermittent operations. Petitioners provided several examples (*e.g.,* temporary fuel conditioning skids, small compressor injection, and liquids unloading events) that require the usage of TPCs. For these scenarios, petitioners requested that the EPA exempt TPCs from the zero-emissions standards prescribed by the March 2024 Final Rule. Petitioners cited several reasons to provide relief for these devices, including the economic burden of retrofitting a handful of TPCs for minimal incremental emissions benefit, the risk of triggering a modification when bringing TPCs on site, and operational challenges with zero-emitting controllers when the necessary infrastructure is not yet in place.

Petitioners classified the intermittent usage of TPCs into two main scenarios: (1) embedded into TCD/BCDs and (2) used during the construction phase at a given facility (*e.g.,* drilling or well completions). For the scenario of embedment into TCD/BCDs, petitioners claimed that third parties often lease or own TPCs, thereby limiting the inventory of devices able to "plug in" to the site's permanent design. Moreover, petitioners stated that the March 2024 Final Rule is prohibitive in these scenarios since natural-gas-driven TPCs that permanently attach to TCD/BCDs could trigger modification without significant capital spending or planning if brought on site. Furthermore, petitioners claimed difficulty in retrofitting natural-gas-driven TPCs to comply with the zero-emission standards in a relatively short amount of time, without significant financial investment, for equipment that owners and operators might not directly own.[235]

[235] API (2025).

For the scenario of usage during the construction phase at a given facility, petitioners claimed that facilities readily use TPCs during this scenario. Even if a site intends on using low emitting process controllers during normal operations, the site may not have electricity or compressed air available to power the actuation of these devices. As such, sites may use TPCs in the interim to continue the construction of the site. Petitioners asked the EPA to exempt process controllers used during the construction phase of a site to provide relief.

Summary of Proposed Changes and Rationale. After further review and consideration of the petitions regarding TPCs embedded into TCDs, the EPA acknowledges that, while TPCs are not always needed as part of a TCD configuration, TPCs are nevertheless frequently attached to TCDs for certain phases of operation. The EPA also finds the petitioners' concerns legitimate in that temporary equipment cannot plug into permanent site utilities (*e.g.*, instrument air or electrical systems), which are designed only for permanent equipment. Retrofitting rented equipment that the facility does not own is also likely not allowed by the rental company per the rental agreement, along with being considered impractical and uneconomical. Moreover, certain site construction and flowback phases lack the necessary infrastructure to support zero emission controllers (where zero-emission infrastructure is often not present during construction, drilling, or flowback), temporary equipment is on-site only briefly, and the compliance requirements in the March 2024 Final Rule were designed under a framework for permanent, and not transient, devices.

As such, the EPA proposes to revise the requirements in NSPS OOOOb, and the presumptive standards in EG OOOOc, for process controllers that are embedded to TCDs for intermittent activities. These proposed changes entail treating process controllers that are permanently embedded into TCDs differently. The proposed changes will still allow these process controllers to comply with the zero-emission standard but will also provide

an alternate "low bleed" standard for up to 30 operational days per site per year (on a 12-month rolling basis), with associated recordkeeping. This "low bleed" standard takes after provisions introduced in the March 2024 final rule for process controllers in Alaska with natural gas-driven continuous bleed that lack access to power because of the site's limited infrastructure and remoteness. In these provisions, the low-bleed process controllers allow for no greater than 6 scfh in bleed rate.[236] The EPA proposes that following 30 operational days, a site may continue to comply with the alternate "low bleed" standard for these process controllers up to 60 additional operational days per site per year (on a 12-month rolling basis), with additional recordkeeping as described in section III.H.1.e. of this preamble. These proposed changes impact NSPS OOOOb (40 CFR 60.5390b(b)) and EG OOOOc (40 CFR 60.5394c(b)).

The March 2024 Final Rule also includes a yet to be fully "phased in" zero-emitting standard for process controllers that did not take into account process controllers used at a particular site for a limited amount of time, before removal from the site. Operators can comply by using multiple options, including using electricity- or compressed air-powered devices, instead of natural gas. Because TPCs are usually rented, owners and operators find it difficult to locate controllers that are compatible with the large variety of site designs. While some sites may have electricity from the power grid or air compressors already on site, remote locations or other certain locations often do not. To address this issue, TPC rental companies need to have varied TPC types at the ready to "plug-in" to sites with potentially different emission control requirements. Logistically, it may be difficult to maintain an inventory of multiple TPC types, particularly when multiple owners and operators in a region require the same type of TPC at the same time.

[236] 89 FR 16830, 16883 (March 8, 2024).

Moreover, there may also be emergency situations where owners and operators will need to use TCD/BCDs that are permanently attached to natural-gas-driven process controllers. In these cases, the facility would need to retrofit and potentially modify equipment they do not own to meet the zero-emitting provisions or risk being out of compliance. Given the urgency in response, these modifications could increase the site's response time or lead to unnecessary venting. Therefore, the EPA proposes to provide alternate compliance standards from the zero-emitting provisions for TPCs embedded to TCDs.

Summary of Comment Solicitation. The EPA agrees with petitioners that standalone TPCs used during the construction phase of an oil and gas site fundamentally differ from TPCs embedded into TCDs. While both devices function similarly, standalone TPCs used during the construction phase can connect to transient machinery that normal well operation does not require. Thus, the number of standalone TPCs on site during the construction phase may vary substantially during this time. The EPA has not received sufficient information on the number of standalone TPCs used for the construction phase of a well, or the average number of days of having these devices on site. Thus, the EPA proposes no changes for standalone TPCs that are not embedded into TCDs. The EPA invites comment on the incidence of standalone TPCs present during the construction phase of a well and what the alternate standard from the zero-emitting provisions in the March 2024 Final Rule for these devices should be, along with providing any supporting information that the EPA can consider regarding TPCs that are not utilized as part of a TCD configuration. (Question III.7d)

g. Control Device Categories

Background. The March 2024 Final Rule outlines different operating and monitoring requirements based on the type of control device but does not provide definitions for the various control device categories. Petitioners stated that without clear

definitions, operators and vendors may be confused about which set of requirements apply to a particular control device.[237] For example, NSPS OOOOb currently prescribes different requirements for air-assisted flares or enclosed combustion devices that use either perimeter assist air or premix assist air, and subsequently whether you must calculate NHV_{dil} or NHV_{cz} (which use different equations).[238] Therefore, petitioners requested that the EPA clarify the control device requirements by including the following seven definitions from NESHAP subpart CC for Petroleum Refineries[239] in NSPS OOOOb.

> *Assist air* means all air that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. *Assist air* includes premix assist air and perimeter assist air. *Assist air* does not include the surrounding ambient air.
>
> *Assist steam* means all steam that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. *Assist steam* includes, but is not necessarily limited to, center steam, lower steam and upper steam.
>
> *Center steam* means the portion of assist steam introduced into the stack of a flare to reduce burnback.
>
> *Lower steam* means the portion of assist steam piped to an exterior annular ring near the lower part of a flare tip, which then flows through tubes to the flare tip, and ultimately exits the tubes at the flare tip.
>
> *Perimeter assist air* means the portion of assist air introduced at the perimeter of the flare tip or above the flare tip. *Perimeter assist air* includes air intentionally entrained in lower and upper steam. *Perimeter assist air* includes all assist air except premix assist air.
>
> *Premix assist air* means the portion of assist air that is introduced to the flare vent gas, whether injected or induced, prior to the flare tip. *Premix assist air* also includes any air intentionally entrained in center steam.
>
> *Upper steam* means the portion of assist steam introduced via nozzles located on the exterior perimeter of the upper end of the flare tip.

---

[237] API & AXPC (2024a); and API & AXPC (2024b).
[238] 40 CFR 60.5417b(d)(8)(iv)(D)-(F) and 40 CFR 60.5417b(d)(8)(vi)(A).
[239] 40 CFR 63.641.

Summary of Proposed Changes and Rationale. The EPA agrees with the petitioners on the need for clarity regarding the control device requirements, because the March 2024 Final Rule has different requirements depending on the type of control device. Therefore, the EPA is proposing to include these definitions from NESHAP subpart CC in NSPS OOOOb. The EPA solicits comment on proposing to add these definitions to NSPS OOOOb (40 CFR 60.5430b) for clarity. (Question III.7e)

h. Other Test Method 52A (OTM-52A)

Background. The EPA is aware from petitioner requests[240] that NSPS OOOOb affected sources are interested in the use of alternative testing approaches and methods to demonstrate compliance with the standards for ECDs. In addition to the prescribed methods already included in the NSPS OOOOb (and EG OOOOc) rule, petitioners have requested the EPA to add Other Test Method 52A (OTM-52A)[241] as an allowable test method option to satisfy compliance with the ECD standards.

The EPA notes that one approach for using OTM-52A already exists. As indicated in ONG Reconsideration #1,[242] if a source wants to use an alternative method (such as OTM-52A) to demonstrate compliance with an alternative combustion efficiency standard, the owner or operator may follow the procedures in 40 CFR 60.5412b(d) to request approval of an alternative test method. The EPA also notes that the current stack testing requirements for NSPS OOOOb (and EG OOOOc) sources are based upon total organic compound (TOC) removal efficiency (*i.e.*, TOC in versus TOC out), whereas OTM-52A is based upon TOC combustion efficiency (*i.e.*, hydrocarbon-to-CO2 conversion). These represent two separate and distinct approaches for demonstrating compliance with the prescribed TOC limits. While the EPA has allowed for an alternative

---

[240] API & AXPC (2024a), API & AXPC (2024b), and API (2025).
[241] Other Test Method 52A (OTM-52A) Method for Determination of Combustion Efficiency from Enclosed Combustion Devices Located at Oil and Natural Gas Facilities Using Method 25A (June 26, 2025) at *https://www.epa.gov/system/files/documents/2025-07/otm-52a_07142025.pdf*.
[242] 91 FR 18064 (April 9, 2026).

combustion efficiency standard for ECDs in 40 CFR 60.5412b(d), there is concern that the provisions may not be written in a manner that clearly allows for the use of an alternative method, such as OTM-52A. Any petition requesting approval to use OTM-52A as a potential alternative test method (as described above) would have to address this key difference.

Summary of Comment Solicitation. The EPA is soliciting comment on the practical use of a method based on OTM-52A for demonstrating compliance with the NSPS OOOOb stack testing requirements for enclosed combustion devices. Specifically, the EPA seeks feedback on field applicability, data quality, and implementation feasibility of using a combustion-efficiency-based method in lieu of traditional removal efficiency approaches. The EPA also requests general comments on the OTM-52A method, including but not limited to, test duration, procedures, and QA/QC. In addition, the Agency is requesting comment on whether the provisions for alternative test methods in 40 CFR 60.5412b(d) would prevent the use of a combustion efficiency method such as OTM-52A, and whether different performance testing requirements should be considered for enclosed combustion devices that operate intermittently. (Question III.7f) The EPA is also taking comment on whether the Agency should specifically allow, by rule, the use of OTM-52A, at least until the EPE develops its own official version (*i.e.*, EPA Method "XX"). Beyond the broad question of whether OTM-52A (or a method based on OTM-52A) should be allowed, the EPA is seeking input on any specific considerations related to how the alternative could be incorporated, and whether it would require any other changes (such as an alternative compliance limit) to demonstrate any differences between a testing approach on removal efficiency vs combustion efficiency, and specifically what those changes should be. (Question III.7g)

I. Equipment Leaks at Gas Plants

1. Background

Under the March 2024 Final Rule, the NSPS OOOOb standards and the OOOOc EG (presumptive standards) apply to the "process unit equipment" affected and designated facilities and require that, for each piece of equipment that has the potential to emit methane or VOC (methane only for designated facilities), owners and operators conduct bimonthly (*i.e.*, once every other month) OGI monitoring in accordance with 40 CFR part 60, Appendix K to detect equipment leaks from pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor or light liquid service, connectors in gas/vapor or light liquid service, and CVSs. As an alternative to the bimonthly OGI monitoring, facilities may use EPA Method 21 to detect leaks from the same equipment at frequencies specific to the process unit equipment type (*e.g.*, monthly for pumps, quarterly for valves). Facilities must use AVO to monitor open-ended valves and lines, pumps, valves and connectors in heavy liquid service, and pressure relief devices in light liquid or heavy liquid service. The March 2024 Final Rule, including the presumptive standards, requires that a facility must repair a leak after its detection. Facilities must repair valves by replacing the leaking valve with a low emission (low-E) valve, where technically feasible. The March 2024 Final Rule also requires that facilities must tag the leaking equipment for identification, commence a first attempt at repair for all identified leaks within 5 days after detection, and complete final repair within 15 days after detection (unless the delay-of-repair provisions apply). The EPA allows delay of repair where it is technically infeasible to complete repairs within 15 days without a process unit shutdown. In addition to the monitoring and repair requirements, the March 2024 Final Rule includes other equipment and monitoring requirements for specific types of equipment (*e.g.*, an open-ended valve or line must be equipped with a closure device).

Under the March 2024 Final Rule, the EPA requires semiannual reporting for process unit equipment affected facilities. Inspection records required in the March 2024 Final Rule consist of:

- Equipment identification
- Date of inspection
- Start and end times of inspection
- Inspector name
- Leak determination method
- Monitoring instrument identification
- Type of equipment monitored
- Process unit identification
- Appendix K records (where applicable)
- EPA Method 21 instrument readings and calibration results (where applicable)
- For visual inspections, the date, name of inspector, and result of inspection

2. Additional Background and Summary of Proposed Changes and Rationale

Petitioners raised two issues with the requirements in the March 2024 Final Rule for equipment leaks at natural gas processing plants.[243]

The first issue raised by petitioners involves a request for the EPA to reconsider the March 2024 Final Rule low-E valve repair requirements. Petitioners requested revisions to the provisions to allow for a first repair attempt using other, less costly actions such as those found in NSPSs KKK, OOOO, and OOOOa. Petitioners contended that without this first attempt at repair allowance, additional emissions could result from process unit shutdowns and/or piping blowdowns that a low-E repair may require.[244]

The second issue raised by petitioners involves a request that the EPA reconsider the elimination of the applicability threshold of 10 percent VOC by weight and that the

[243] API & AXPC (2024b).
[244] API & AXPC (2024b). pg. 25.

EPA add a threshold of 1 percent methane by weight in order to limit the number of additional components with low or no concentrations of the regulated pollutant from tagging and monitoring.

Sections III.I.2.a and b of this preamble provide the petitioners' concerns and supporting information, summary of proposed changes, and basis for proposed changes for both of these issues.

a. Low-E Valve Repair Requirements

Background. Petitioners raised concerns with the March 2024 Final Rule requirement that leaking valves at natural gas processing plants be repaired with low-E packing or replaced with low-E valves unless demonstrated to be technically infeasible.[245, 246] Petitioners requested that the low-E valve repair requirements be revised to allow for a first repair attempt using other, less costly actions such as those found in NSPS KKK, OOOO, and OOOOa, which include:

- Tightening of bonnet bolts;
- Replacement of bonnet bolts;
- Tightening of packing gland nuts; and
- Injection of lubricant into lubricated packing.

Petitioners explained that most leaks can be repaired using these first repair attempt actions and expressed concern that eliminating these first repair attempt actions and requiring a low-E repair would create environmental disbenefits. Specifically, they noted that additional emissions could result from process unit shutdowns and/or piping blowdowns that may be required for a low-E repair. Petitioners recommended that the EPA revise the March 2024 Final Rule to allow these first repair attempt actions instead of a low-E valve repair or at a minimum before requiring a low-E valve repair.

---

[245] API & AXPC (2024b).
[246] 40 CFR 60.5400b(h)(2)(ii) and 60.5401b(i)(2)(ii), and 40 CFR 60.5400c(h)(2)(ii) and 60.5401c(i)(2)(ii).

Petitioners asserted that the March 2024 Final Rule inaccurately characterized low-E valves and packing as having no additional costs compared to traditional valves and packing. In their experience, low-E valves and packing are more expensive. They stated that they were not able to provide cost information or comments on this issue prior to the March 2024 Final Rule because the low-E valve repair requirements were not included in the November 2021 Proposal or December 2022 Supplemental Proposal. Consequently, they requested administrative reconsideration of the low-E valve repair requirements.

Summary of Proposed Changes and Rationale. Petitioners[247] are correct that the low-E valve repair requirements that the EPA finalized in 2024 were not included in the November 2021 Proposal or December 2022 Supplemental Proposal. In the November 2021 Proposal, the EPA proposed repair requirements for leaking equipment. In the November 2021 Proposal, the EPA proposed that the definition of "repaired" (for equipment) included that the equipment be adjusted, replaced, or otherwise altered, in order to eliminate equipment leaks and that the equipment be re-monitored to verify that emissions from the equipment are below the leak definition.[248] The EPA explained at that time that valve repairs can include replacement with low-E valves, valve packing, or drill-and-tap with a low-E injectable ("low-E equipment") but the Agency did not require replacement with low-E equipment. The EPA explained that low-E equipment meets the specifications of the American Petroleum Institute (API) 622 or API 624 and typically includes a manufacturer written warranty or a performance guarantee that it will not emit fugitive emissions at a concentration greater than 100 ppmv during the first 5 years.[249] In the December 2022 Supplemental Proposal, the EPA proposed a definition of "repaired" (for equipment) consistent with that discussed in the November 2021 Proposal. The EPA

[247] API & AXPC (2024b).
[248] 86 FR 63182 (November 15, 2021).
[249] 86 FR 63182 (November 15, 2021).

did not propose to require the replacement of leaking valves with low-E equipment, noting that the technology is not appropriate for all repairs, but reiterated the position from the November 2021 Proposal that due to the performance expectations, low-E equipment can be a viable option for valve repair.[250]

The EPA received comments on the December 2022 Supplemental Proposal that urged the Agency to require replacement of leaking equipment with low-E valves. One commenter cited a recent rulemaking, where Colorado found these options to be similar in cost to non-low-E valves and packing and directed operators to consider them.[251, 252] The commenter also noted that some manufacturers claimed that their low-E packing can reduce emissions of harmful gases by up to 95.0 percent versus valves with traditional packing, with minimal cost impacts.

The EPA responded to these comments on the December 2022 Supplemental Proposal by stating that the commenter's understanding of the cost for low-E equipment aligns with that of the EPA in that they are similar in cost to non-low-E equipment. Therefore, the EPA concluded that replacing leaking valves with low-E equipment would result in lower emissions with no additional cost burden (compared to using non-low-E equipment). As such, the final standard in NSPS OOOOb, and the presumptive standard in EG OOOOc, requires replacing leaking valves with low-E valves or repacking existing valves with low-E packing, except where it is not technically feasible. If delay of repair is required to repack or replace the valve, the final rule allows the use of the delay of repair requirements provisionally, but an owner or operator would not be able to delay valve

---

[250] 87 FR 74808 (December 6, 2022).

[251] EDF, et al. (2023). Public Comment Submission on EPA's December 2022 Supplemental Proposal. Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Docket Document ID No. EPA–HQ–OAR–2021–0317–2433.

[252] *See* Colorado Department of Public Health and Environment Air Quality Control Commission. Regulation Number 7. Control of Emissions From Oil and Gas Emissions Operations. 5 CCR 1001-9. Part C. Statements of Basis, Specific Statutory Authority and Purpose. (Leak Detection and Repair: Sections II.E. and II.I.). December 17, 2021.

repair or replacement beyond the next process unit shutdown. The EPA specifically allowed for delay of repair in the March 2024 Final Rule to repack or replace a valve to avoid the need for an owner or operator to shutdown a process unit or conduct a piping blowdown that would result in additional emissions to implement low-E valve repacking or replacement.

The EPA is now proposing to change its position on this matter, compared to the March 2024 Final Rule. The Agency still believes that the costs for low-E equipment can be similar to the costs for non-low-E equipment, especially when taking into consideration the total cost of ownership (*e.g.*, cost savings from less product loss, less compliance and penalty risks). However, some estimates indicate that the upfront costs of a low-E valve can be 25 percent more than the upfront costs for a non-low-E valve, and the EPA acknowledges that there may be even greater upfront cost differences for some low-E valves (depending on the level of automation and valve functionality and temperature and pressure conditions).[253] The EPA solicits low-E valve versus non-low-E valve cost information. (Question III.8a) A "low-E valve" under NSPS OOOOb and the presumptive standard in EG OOOOc, is differentiated from a "non-low-E valve" in that a "low-E" valve is a valve (including its specific packing assembly) for which the manufacturer has issued a written warranty or performance guarantee that it will not emit fugitives at greater than 100 ppm in the first five years. A valve may qualify as a low-E valve if it is as an extension of another valve that has qualified as a low-E valve.

Recognizing that an owner or operator may be able to repair a leaking valve by using less-costly first attempts at repair approaches similar to what is allowed for other equipment components, such as tightening or replacement of bonnet bolts, tightening of packing gland nuts, or injection of lubricant into lubricant packing, the EPA agrees that

---

[253] International Society of Automation (ISA). (2014). Low-Leak Valve Technology. An Update. Slide Presentation. March 18, 2014.

allowing such first attempts at repair is reasonable. As such, the EPA proposes to amend the March 2024 Final Rule to allow owners and operators to conduct a "first attempt at repair" of a leaking valve as defined in 40 CFR 60.5430b and 60.5430c prior to being required to utilize a low-E valve or low-E packing to replace or repack a leaking valve. Under 40 CFR 60.5430b and 60.5430c,

> *[f]irst attempt at repair* means, for the purposes of fugitive emissions components, an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing.

For purposes of equipment leaks at gas plants, the EPA proposes to revise the "first attempt at repair" definition in 40 CFR 60.5430b and 60.5430c to clarify that, "for the purposes of fugitives emissions components and equipment leaks at gas plants," a first attempt at repair is allowed for both fugitive emissions components and equipment leaks at gas plants. This proposed change to the definition is consistent with our proposal to allow for a first attempt at repair prior to requiring owners and operators to utilize a low-E valve or low-E packing to replace or repack a leaking valve at a gas plant. If the first attempt at repair is unsuccessful (*i.e.*, does not eliminate the leak), the EPA proposes that owners or operators must utilize a low-E valve or low-E packing to replace or repack the leaking valve where technically feasible.[254] These proposed changes impact both NSPS OOOOb (40 CFR 60.5400b(h)(2)(ii)) and the presumptive standard in the model rule for EG OOOOc (40 CFR 60.5400c(h)(2)(ii). The EPA believes that this proposal maintains the Agency's goal of mitigating emissions from leaking valves and packing by allowing quick, practical, low-cost mitigation options, such as tightening bolts as a first attempt at repair, while still resulting in a transition to low-E valves/low-E packing in cases where

[254] Repaired, for the purposes of process unit equipment affected/designated facilities, specifically valves, means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in 40 CFR 60.5400b/c and 60.5401b/c and is re-monitored as specified in 40 CFR 60.5400b/c(b) introductory text or 40 CFR 60.5403b/60.5406c, respectively, to verify that emissions from the equipment are below the applicable leak definition.

the initial repair is unsuccessful. This revision mitigates any potential additional costs that would be incurred by having to replace an existing non-low-E valve with a low-E valve where, for example, a simple tightening or replacement of bonnet bolts, tightening of packing gland nuts, or injection of lubricant into lubricant packing can result in an elimination of the leak. The EPA solicits comment on this proposed change. (Question III.8b)

b. De minimis VOC or Methane Applicability Threshold

Background. Petitioners requested that the EPA retain the applicability threshold of 10 percent VOC by weight and add a threshold of 1 percent methane by weight to limit the number of additional components with low or no concentrations of the regulated pollutant from monitoring.[255] They explained that LDAR at natural gas processing plants has a long history of applying only to specific components in VOC service with the following language included in NSPS KKK[256], NSPS OOOO[257], and NSPS OOOOa[258]:

> Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–93, E168–92, or E260–96 (incorporated by reference as specified in 40 CFR 60.17) must be used.

Petitioners asserted the importance of these distinctions within a gas plant as the EPA does not subject many components to LDAR requirements. The LDAR requirements may not apply to a given component if the equipment's location within the gas plant does not

---

[255] API-AXPC (2024b). Re: Request for Administrative Reconsideration of EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review." May 6, 2024. pgs. 26-27.
[256] 40 CFR 60.632(f).
[257] 40 CFR 60.5400(f).
[258] 40 CFR 60.5400a(f).

exceed a VOC content of 10 percent by weight and the equipment has never previously been tagged or incorporated into the fugitive monitoring on process units subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa. Petitioners explained that many gas plants still have permit conditions that require the use of EPA Method 21 instead of OGI to screen for fugitive leaks on process units. For these facilities, they report that all applicable components must be tagged, and that removing the exemption criteria that establish a de minimis threshold results in the need for operators to tag every component at the gas plant. Petitioners argued that operators having to tag each component for monitoring poses a significant undertaking due to the high number of fugitive components located at a gas processing plant.

In the 2016 NSPS OOOOa, the EPA added GHG (methane) to the regulations for equipment leaks at onshore natural gas plants but continued to rely on the requirements in NSPS VVa, which limited monitoring and repair (if found leaking) to those equipment components "in VOC service."[259] In the November 2021 Proposal, the EPA proposed to revise the equipment leak standards for onshore natural gas plants to more readily apply to equipment components that have the potential to emit methane even though they are not "in VOC service."[260] In the December 2022 Supplemental Proposal, consistent with the November 2021 proposal, the EPA proposed to apply the LDAR standards to process unit equipment that has the potential to emit methane or VOC.[261] The EPA proposed that each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the owner or operator would need to demonstrate

[259] 81 FR 35824 (June 3, 2016).
[260] 86 FR 63231 (November 15, 2021).
[261] 87 FR 74808 (December 6, 2022).

that the process fluids in contact with the process unit equipment do not contain either methane or VOC. Under the March 2024 Final Rule NSPS OOOOb and EG OOOOc:[262]

> Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of appendix A-6 to this part. Alternatively, if the piece of equipment is in wet gas service, you may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16(R2023), E169-16(R2022), or E260-96 (all incorporated by reference, see 40 CFR 60.17). [Note: VOC is not included for EG OOOOc citations.]

According to the petitioners, some streams at gas processing plants contain methane or VOCs in such low concentrations that monitoring would nearly always result in no detected emissions, rendering the monitoring obsolete. Examples of such streams provided by the petitioners include but are not limited to pure ethane, acid gas streams (*i.e.,* hydrogen sulfide (H_2S)), and ancillary chemicals. By requiring EPA Method 18 monitoring of additional components that they have not previously had to monitor with no appreciable amounts of VOC or methane, petitioners reported that there would be an added cost that uses personnel resources with minimal, if any, environmental benefit. Petitioners also noted that many gas plants still have permit conditions that require the use of EPA Method 21 instead of OGI to screen for fugitive leaks on process units. For these permitted facilities, operators must tag all applicable components. As such, by removing the exemption criteria based on a de minimis threshold, operators must tag every component at the gas plant.

To address their concerns, petitioners requested that the EPA retain the applicability threshold of 10 percent VOC by weight and that the Agency add a threshold of 1 percent methane by weight to limit the number of additional components with low or no concentrations of the regulated pollutant from monitoring.

---

[262] 40 CFR 60.5400b(a)(2), 60.5401b(a)(2), 60.5400c(a)(1), and 60.5401c(a)(1).

Summary of Proposed Changes and Rationale. The EPA acknowledges the petitioners' concerns that gas processing plants may contain some streams with methane or VOC in low concentrations. Commenters on the NSPS and EG December 2022 Supplemental Proposal had similarly requested that the EPA maintain the 10 percent by weight VOC concentration threshold and add a 1 percent by weight methane concentration threshold to exclude ethane product streams, produced water streams, and wastewater streams. [263] At that time, the EPA noted that no additional data were provided to indicate that a threshold of 1 percent by weight methane would be appropriate. The EPA also noted that studies indicated that produced water and wastewater streams can be significant sources of VOC emissions.[264] Therefore, the EPA maintained that equipment monitoring applicability based on the potential to emit VOC or methane was appropriate.

Petitioners on the March 2024 Final Rule raised as they had previously in their comments on the proposed rule, concerns that some streams at gas processing plants contain methane or VOC in such low concentrations that facilities almost always receive monitoring results of no detected emissions, rendering monitoring obsolete. However, petitioners provided information that such streams also include, but are not limited to pure ethane, acid gas streams (*i.e.*, H_2S), and ancillary chemicals. The EPA maintains that produced water and wastewater streams, as it did in the final rule preamble, can be significant sources of VOC emissions. However, the EPA acknowledges that some of the natural gas processing streams highlighted by the petitioners (*i.e*., pure ethane, acid gas streams (*i.e.,* H_2S)) support their concerns. Pure ethane and acid gas streams would not contain appreciable, if any, VOC or methane. The EPA also recognizes that a lot of ancillary chemicals used in natural gas processing may not contain VOC or methane (*e.g.*, sodium carbonate, sodium silicate) or only include VOC or methane in small

[263] 87 FR 74808 (December 6, 2022).
[264] California Air Resources Board (CARB) (2020). Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations. Final Report. May 2020. Available at: https://ww2.arb.ca.gov/.

amounts. The EPA also acknowledges that equipment leak component monitoring on process units subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa (which include a VOC content of 10 percent by weight applicability threshold) have resulted in many components not being subject to LDAR requirements and have never previously been tagged or subject to the equipment leak monitoring requirements of NSPS KKK, NSPS OOOO, or NSPS OOOOa. Under the March 2024 Final Rule provisions, the EPA recognizes that having to tag each equipment emissions component located at a natural gas processing plant for monitoring would be a significant undertaking considering the number of equipment emissions components located at a natural gas processing plant.

EPA Method 18 is designed for ppm level sources (EPA Method 18, section 1.2.1). As such, very small traces of methane or VOC in a gas stream may be detectable using EPA Method 18. This supports the petitioners' statements that the current requirements related to potential to emit methane or VOC could effectively require monitoring of all process unit equipment components. The EPA Method 21 leak definition is 500 ppmv. As such, it is possible to have gas streams that have a detectable concentration of methane and/or VOC that do not result in a process unit equipment component with a detectable leak. In general, the Agency expects that the vast majority of process unit equipment components at a natural gas processing plant will be in methane or VOC service when implementing a 1 percent by weight and 10 percent by weight thresholds for methane and VOC, respectively.

The average methane compositions for components in VOC and non-VOC service when modeling the impacts of different LDAR programs were well over 50 percent by weight.[265] As such, the EPA believes that a 1 percent by weight methane threshold would

[265] U.S. EPA (2021). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG). October 2021. *See* section 10.4.1.1 (Equipment Leak Model).

effectively require monitoring of the predominant processes and streams at the natural gas processing plant. The EPA also believes that gas streams with trace quantities of methane or VOC would not appreciably contribute to the plant's methane or VOC emissions due to (1) the paucity of components that the 1 percent by weight methane and 10 percent by weight thresholds would exclude, and (2) the low methane and VOC mass emissions that may occur from excluded components given the low concentrations of regulated pollutants in these streams.

However, the EPA does not have sufficient data at this time to validate a threshold of 1 percent by weight methane. While the EPA believes a 1 percent by weight methane threshold is a conservative threshold that likely limits monitoring of components to only those components processing natural gas in appreciable amounts, the Agency requests specific information and monitoring data for processing equipment at natural gas plants that would support a 1 percent by weight equipment applicability methane concentration threshold. (Question III.8c) The Agency is also requesting specific information and monitoring data for processing equipment at natural gas plants to support a 10 percent by weight equipment applicability VOC concentration threshold. (Question III.8d)

In conclusion, the EPA proposes to revise the March 2024 NSPS OOOOb and EG OOOOc regulatory language at 40 CFR 60.5400b(a) and 60.5400c(a) to change the equipment applicability threshold to be 10 percent by weight for VOC and 1 percent by weight methane. In addition, the EPA proposes to add definitions for "[i]n VOC service" and "[i]n methane service" and revise the definition for "[e]quipment" at 40 CFR 60.5430b and 60.5430c to reflect the addition of the VOC and methane applicability threshold additions. The EPA also proposes to revise the definition of "[e]quipment" in NSPS OOOOb and EG OOOOc to include equipment "[i]n wet gas service" that parallels language in NSPS OOOOa, which the Agency inadvertently excluded in the March 2024

Final Rule definitions. The EPA believes that the Agency's proposed regulatory changes to NSPS OOOOb and EG OOOOc have practicality, and that the revision to the definition of "[e]quipment" to include the reference to "in wet gas service" corrects an inadvertent omission that increases clarity. The EPA solicits comment on the appropriateness of a 10 percent by weight VOC concentration and 1 percent by weight methane concentration and equipment thresholds, as well as any additional data or analyses that support or challenge these concentration levels. The Agency also solicits general comments on all aspects of these proposed changes. (Question III.8e)

c. Additional Requests for Comment

In addition, for purposes of setting monitoring requirements for equipment leaks at gas plants, the EPA seeks comment (including data and detailed information) on how often equipment leaks are found at gas plants, the approximate volume of gas emitted during a typical fugitive emissions event at a gas plant, estimates regarding the approximate length of time that equipment leak events lasts at gas plants, and the cost of conducting monitoring for equipment leaks (*e.g.*, capital costs, variable costs, changes to business practices, safety implications of conducting the fugitives monitoring, and any other relevant costs). (Question III.8f)

The EPA is also soliciting comment on the cost effectiveness and cost reasonableness of the gas plant requirements generally. The EPA is specifically requesting information on the appropriate frequency, type of monitoring technology, and other relevant information that may improve the EPA's cost effectiveness and cost reasonableness analysis, allowing the EPA to better target emission reductions and the EPA also seeks comment on whether the gas plant requirements in the March 2024 Final Rule are necessary considering this information. (Question III.8g)

J. Associated Gas from Wells Producing Primarily Oil

1. Background

Under the March 2024 Final Rule, NSPS OOOOb and EG OOOOc establish standards and presumptive standards, respectively, for associated gas from wells operated primarily for oil production at well affected and designated facilities. Subject to certain caveats for existing sources, the rule generally requires each well producing associated gas to reduce emissions to the atmosphere through work practices, with some limited allowances for routine or emergency flaring as discussed in more detail below. The work practice standards require operators to recover the associated gas from the separator and either route it to a gas gathering flow line or a collection system leading to a sales line, use it as an onsite fuel source, use it for another beneficial purpose that would otherwise rely on a purchased fuel, chemical feedstock, or raw material, or reinject it into the same well or into another well. *See* 40 CFR 60.5377b. Any emissions the operator routes to a control device or flare must be routed through a CVS to a control device which meets the requirements summarized in section III.G and H of this preamble. *See Id.* at 40 CFR 60.5377b(d) and (f).

The NSPS OOOOb provisions under the March 2024 Final Rule separated new wells that produce associated gas into groups based on when construction is/was commenced. New wells in the first group (*i.e*., those wells that commence construction after May 7, 2026) are required to comply with the work practice standards and cannot routinely flare. The final standards do not allow these wells to routinely flare emissions because the EPA determined, when it finalized the March 2024 rule, that, with advance planning, at least one of the options to avoid routine flaring would be feasible at these wells (including routing the gas to a sales line, using the gas as an onsite fuel source, using the gas for another beneficial purpose that a purchased fuel, chemical feedstock, or raw material would serve, or reinjecting it into the well or into another well).

Wells in the second group (*i.e.*, wells that commence construction between May 7, 2024, and May 7, 2026) were required to comply with the final standard of no routine

flaring on or before May 7, 2026. During the interim period between May 7, 2024, and May 7, 2026, these wells were allowed to route the associated gas through a CVS to a flare or control device achieving at least 95.0 percent reduction of methane and VOC emissions, provided the owner and/or operator demonstrated that the work practice standard options discussed above were technically infeasible. The determination of technical infeasibility was required to be certified by a professional engineer or other qualified personnel, the flare or control device must meet the requirements of 40 CFR 60.5412b, and the CVS must meet the requirements of 40 CFR 60.5411b(a) and (c). After May 7, 2026, these wells were no longer allowed to flare routinely (with or without a showing of technical infeasibility) and were subject to the work practice standards.

For wells in the third group (*i.e.*, wells that commenced construction, were modified, or were reconstructed, between December 6, 2022, and May 7, 2024), the March 2024 Final Rule allows routing the associated gas through a CVS to a flare or control device that reduces methane and VOC emissions by at least 95.0 percent on a routine basis, provided that the owner or operator documents and certifies that complying with the work practice standards is technically infeasible. As required for the wells in the second group, the determination of technical infeasibility must be certified by a professional engineer or other qualified personnel, the flare or control device must meet the requirements of 40 CFR 60.5412b, and the CVS must meet the requirements of 40 CFR 60.5411b(a) and (c). This allowance for technical infeasibility is provided for a period of 1 year at a time. Therefore, owners and operators of wells in the third group must renew the technical infeasibility determination/certification annually to continue routing the associated gas to a flare or control device.

Consequently, since May 7, 2026, all oil wells subject to NSPS OOOOb that were constructed, reconstructed, or modified after May 7, 2024, have been required to route their associated gas to a gas gathering line or collection system to a sales line, recover the

associated gas and use it as an onsite fuel source or other beneficial use, or recover the associated gas and reinject it into a well, or, under specific scenarios, are allowed to temporarily flare emissions.[266, 267]

The model rule for the 2024 final EG separates existing oil wells that produce associated gas into two groups based on the amount (mass) of methane in the associated gas. The demarcation between these two groups is 40 tpy of methane. For existing wells that produce associated gas with over 40 tpy of methane, the presumptive standard applies the same work practice requirements that apply to new sources. However, if all of these options are technically infeasible, then the model rule allows these existing wells (*i.e.*, those producing associated gas with more than 40 tpy of methane) to route associated gas through a CVS to a flare or control device that achieves 95.0 percent reduction in methane. This pathway also requires a determination of technical infeasibility certified by a professional engineer or other qualified personnel, the flare or control device meeting the requirements of 40 CFR 60.5412c, the CVS meeting the requirements of 40 CFR 60.5411c(a) and (c), and an annual recertification of technical infeasibility. For wells that produce associated gas containing less than 40 tpy methane, the model rule's presumptive standard allows owners or operators to route associated gas through a CVS to a flare or control device that achieves 95.0 percent reduction in methane without any technical infeasibility determination. The key difference for these two different groups of existing wells is that for wells with annual methane in the associated gas greater than 40 tpy owners and operators are not required to demonstrate that it is infeasible for technical reasons to utilize any of the work practice options before routing associated gas to a flare or control.

---

[266] 40 CFR 60.5377b(a).
[267] 40 CFR 60.5377b(d)(1)–(4).

For both new and existing oil wells that are routing their associated gas to a sales line, the March 2024 Final Rule provides some limited flexibilities to temporarily flare associated gas or route to a control device that reduces methane and VOC emissions by at least 95.0 in accordance with 40 CFR 60.5377b(d) and 40 CFR 60.5391c(c) under the following conditions:

- For up to 30 days during a temporary interruption in service from the gas gathering line or collection system.
- For up to 72 hours in instances where the associated gas does not meet gas pipeline specifications, or when the composition of the associated gas does not meet the quality requirements for another useful purpose.
- For up to 72 hours during repair and maintenance, including blow downs, a production test, or commissioning, until the incident is resolved. However, under exigent circumstances, owners and operators might be able to route to a flare or control device for more than 72 hours.[268]
- For up to 72 hours when there are instances that a malfunction or incident endangers the safety of operator personnel or the public. However, under exigent circumstances, owners and operators might be able to route to a flare or control device for more than 72 hours.[269]

In all instances where temporary flaring is needed for reasons beyond an owner or operator's control, the NSPS OOOOb and EG OOOOc provisions include backstop provisions that require flaring to cease when an incident triggering the need for flaring has been resolved.

2. Concerns Raised by Stakeholders

---

[268] 91 FR 18093, Apr. 9, 2026.
[269] *Id.*

The EPA has received input from industry stakeholders identifying issues with the NSPS OOOOb and EG OOOOc associated gas standards and presumptive standards.

The concerns raised can be summarized in four basic categories:

(1) Concerns regarding Agency's BSER determination under CAA section 111(b) for associated gas. Industry representatives have requested that the EPA revisit the Agency's previous analyses conducted for associated gas and perform a new BSER analysis for associated gas, including revisiting and revising the technical infeasibility requirements.

(2) Situations, many related to third-party gas gathering line or collection systems, that prevent operators from complying with the temporary flaring allowances in 40 CFR 60.63.77b(d)(3) and (4) and 40 CFR 60.5391c(c)(3) and (4) within the allowable timeframes.

(3) Instances where owners and operators of wells constructed during the window of May 7, 2024, and May 7, 2026, were required to comply with one or more of the options in 40 CFR 60.5377b(a) by May 7, 2026, and had arrangements to route the associated gas to a gas gathering line or collection system. Operators report that due to construction delays compliance was not possible by the flaring allowance "phase-out" date. Stakeholders note that this situation is not unique to the 2024-2026 group of wells; any new well that is constructed where an owner or operator plans to connect to a nearby gas gathering line or collection system may face similar compliance challenges if unable to immediately connect upon well start-up due to delays in construction of the gas gathering line or collection system.

(4) Areas where there are no existing oil and natural gas operations and no gas gathering lines or collection system pipelines, where midstream companies will not build gas gathering lines or collection infrastructure until there is

sufficient gas from the area to justify the investment. In these instances, operators assert that wells cannot be drilled under the provisions of NSPS OOOOb because the wells cannot meet the requirement to connect to a gas gathering line or collection system (or employ any of the other compliance options).

Sections III.J.2.a through III.J.2.d provide more details on the concerns raised by industry:

a. EPA's Approach to BSER and Technical Infeasibility Requirements

Industry representatives submitted letters to the EPA disagreeing with the Agency's BSER determination in the 2024 Final Rule, under CAA section 111(b), for associated gas, particularly where the BSER includes "requirements that will phase out and eventually prohibit routine flaring of associated gas" from wells that were new or modified as of 2022.[270, 271, 272] According to one industry representative, connecting a well to a gathering system is not a technology and it is not a retrofit; rather, they argue it is an incorrect determination by the EPA to treat the identification of, and reliance on, a third-party gas gathering system to connect to and accept associated gas as BSER. They contend that the "achievable" degree of emissions reduction from such connection is zero in areas where connection to a gas gathering line or collection system is technically infeasible, particularly in many high-producing, rapidly developing regions where there

---

[270] Kraken Oil and Gas Partners LLC (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 24, 2026.

[271] Continental Resources (2026a). Letter to the EPA Administrator. Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Request for EPA's reconsideration of the BSER for associated gas and the requirements governing technical infeasibility determinations under in 40 C.F.R. § 60.5377b. April 23, 2026.

[272] Continental Resources (2026b). Re: Standards of Performance for Crude Oil and Natural Gas Facilities, 40 C.F.R. Part 60, Subpart OOOOb: Supplemental Operational Scenarios and Conceptual Framing in Support of Continental Resources' April 23, 2026, Letter Requesting Reconsideration of the BSER for Associated Gas and the Technical Infeasibility Demonstration Provisions in 40C.F.R. § 60.5377b. June 16, 2026.

are no other options for compliance.[273] The industry representative stated that requiring any new well to connect to a midstream gas gathering system—when such an option is outside the control of the source and is not available—is not an inside-the-fenceline technology (and therefore of questionable legality under the Supreme Court's 2022 decision in *West Virginia*). They added that the cost for midstream companies to construct pipelines to these wells is exorbitant and therefore unreasonable under relevant precedent, citing the D.C. Circuit's 1973 decision in *Essex Chemical Corporation*. For these reasons alone, the industry representatives asserted, the EPA should conclude that eliminating routine flaring is not BSER. The industry representative requested that the EPA fully rescind and revise the BSER determination for associated gas.[274] In the short-term, both industry representatives suggested that the EPA extend the allowance for flaring based on technical infeasibility and modify the technical infeasibility demonstration provisions to provide temporary relief.

b. Temporary Flaring Allowances

Several industry representatives with operations in, or in close proximity to, the Williston Basin submitted letters to the EPA indicating that there are circumstances in which they cannot meet the requirements to route associated gas to a gathering or collection system to a sales line, recover the associated gas and use it as an onsite fuel source or other beneficial use, or recover the associated gas and reinject it into a well.[275,]

---

[273] Kraken Oil and Gas Partners LLC (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 24, 2026.

[274] Continental Resources (2026b). Re: Standards of Performance for Crude Oil and Natural Gas Facilities, 40 C.F.R. Part 60, Subpart OOOOb: Supplemental Operational Scenarios and Conceptual Framing in Support of Continental Resources' April 23, 2026, Letter Requesting Reconsideration of the BSER for Associated Gas and the Technical Infeasibility Demonstration Provisions in 40 C.F.R. § 60.5377b. June 16, 2026.

[275] Continental Resources (2026a). Letter to the EPA Administrator. Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Request for EPA's reconsideration of the BSER for associated gas and the requirements governing technical infeasibility determinations under in 40 C.F.R. § 60.5377b. April 23, 2026.

Specifically, industry representatives informed the EPA that even when operators are connected to existing gas gathering lines or collection systems, some operators are experiencing capacity constraints in the downstream pipeline, storage, and processing network used to transmit the associated gas to market; or gas quality issues not allowing them to route gas to a sales line. Companies, including Continental Resources, Inc.,[280] Chord Energy Corporation,[281] and Kraken Oil & Gas Partners LLC,[282] informed the EPA of several scenarios where gas gathering or collection system infrastructure capacity constraints outside of an operator's control may result in an oil well being unable to comply with the associated gas control options specified in the NSPS OOOOb. Examples provided by industry include situations when: (1) third-party sales gas gathering lines or collection systems not accepting all or part of the associated gas from an individual oil well because the system is at full capacity or operating at full sales line pressure; (2)

---

[276] Continental Resources (2026b). Re: Standards of Performance for Crude Oil and Natural Gas Facilities, 40 C.F.R. Part 60, Subpart OOOOb: Supplemental Operational Scenarios and Conceptual Framing in Support of Continental Resources' April 23, 2026, Letter Requesting Reconsideration of the BSER for Associated Gas and the Technical Infeasibility Demonstration Provisions in 40C.F.R. § 60.5377b. June 16, 2026.

[277] Chrod Energy (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. pt. 60, subpt. OOOOb: Reconsideration of the Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 17, 2026.

[278] Kraken Oil and Gas Partners LLC (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 24, 2026.

[279] KODA Resources Operating LLC (KODA) (2026). Letter Re: Example of its North Dakota development in support of additional clarifications regarding the associated gas flaring provisions at 40 C.F.R. § 60.5377b. May 5, 2026.

[280] Continental Resources (2026a). Letter to the EPA Administrator. Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Request for EPA's reconsideration of the BSER for associated gas and the requirements governing technical infeasibility determinations under in 40 C.F.R. § 60.5377b. April 23, 2026.

[281] Chrod Energy (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. pt. 60, subpt. OOOOb: Reconsideration of the Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 17, 2026.

[282] Kraken Oil and Gas Partners LLC (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 24, 2026.

unpredictable well surges that exceed the gas pipeline network system capacity; or (3) market conditions result in negative gas prices and supply exceeds demand. In response to gas gathering line or collection system capacity concerns, the EPA issued a Press Release[283] and a memorandum[284] that acknowledged that operators are experiencing capacity constraints in the downstream pipeline, storage, and gas processing network used to get the associated gas to market. The press release and memorandum pointed out that 40 CFR 60.5377b(d)(3) allows operators to route associated gas to a flare or control device for the duration of a temporary interruption, for up to 30 days per incident, and indicated that the Agency considers that applying this provision for situations involving temporary gas gathering line or collection system capacity constraint instances is appropriate.

In addition to gas infrastructure capacity issues, industry representatives also raised concerns about circumstances in which a third party gas gathering line or collection system operator does not accept associated gas or the gas cannot be used onsite because of gas quality issues related to elevated H_2S gas content, BTU specifications and hydrate formation gas quality issues where more than the 72 hours allowable for flaring under 40 CFR 60.5377b(d) is needed to resolve.[285, 286]

---

[283] EPA Press Release: EPA Clarifies When Oil and Natural Gas Producers Can Flare After Phase Out Deadline. https://www.epa.gov/newsreleases/epa-clarifies-when-oil-and-natural-gas-producers-can-flare-after-phase-out-deadline. May 1, 2026

[284] U.S. EPA (2026). Memorandum. Clarification of Regulatory Provisions Concerning Limits on Flaring Associated Gas for New Oil Wells. From Aaron Szabo, OAR Assistant Administrator to Regional Administrators, 1-10. April 30, 2026. Available at: https://www.epa.gov/system/files/documents/2026-04/signed_final_o-g-associated-gas-memo_4-30-26_0.pdf.

[285] Kraken Oil and Gas Partners LLC (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 24, 2026.

[286] Continental Resources (2026b). Re: Standards of Performance for Crude Oil and Natural Gas Facilities, 40 C.F.R. Part 60, Subpart OOOOb: Supplemental Operational Scenarios and Conceptual Framing in Support of Continental Resources' April 23, 2026, Letter Requesting Reconsideration of the BSER for Associated Gas and the Technical Infeasibility Demonstration Provisions in 40C.F.R. § 60.5377b. June 16, 2026.

Following the press release[287] and memorandum,[288] the EPA received a letter from a law firm representing several oil and gas production companies operating in multiple basins across the United States requesting clarification on the guidance that the EPA issued in their April 2026 memorandum.[289] Specific requests for clarification included: (1) how the EPA intends to address situations in which gas gathering line or collection system capacity constraints last longer than 30 consecutive days (*e.g.*, 60 days, 90 days, 6 months, or even years) where the production company's only options are to flare the associated gas or shut-in the oil wells; (2) what happens under the scenario where a midstream gas gathering line company detects elevated levels of H_2S in its gathering flow pipeline or sales pipeline, but cannot identify which well(s) are responsible, and therefore ceases accepting gas from all the wells in the area operated by multiple production companies, while it investigates owners or operators with no option other than flaring its associated gas or shutting-in the well; and (3) how the EPA intends to treat other scenarios involving third-party gas gathering infrastructure access constraints beyond an owner or operator's control where the operator is similarly forced to flare the associated gas or shut-in the well.

c. Flaring Allowance for Wells Where a Connection to a Gas Gathering Line or Collection System Is Underway

As discussed in section III.J.1 of this preamble, wells that commenced construction between May 7, 2024, and May 7, 2026, were required to comply with the final standard of no routine flaring on or before May 7, 2026. In the interim period

---

[287] EPA Press Release: EPA Clarifies When Oil and Natural Gas Producers Can Flare After Phase Out Deadline. https://www.epa.gov/newsreleases/epa-clarifies-when-oil-and-natural-gas-producers-can-flare-after-phase-out-deadline. May 1, 2026.

[288] U.S. EPA (2026). Memorandum. Clarification of Regulatory Provisions Concerning Limits on Flaring Associated Gas for New Oil Wells. From Aaron Szabo, OAR Assistant Administrator to Regional Administrators, 1-10. April 30, 2026. Available at: https://www.epa.gov/system/files/documents/2026-04/signed_final_o-g-associated-gas-memo_4-30-26_0.pdf.

[289] Holland & Hart. (2026). Letter Re: May 1, 2026, Guidance and April 30, 2026, Memorandum: Clarification of Regulatory Provisions Concerning Limits on Flaring Associated Gas for New Oil Wells. Letter to Aaron Szabo, OAR Assistant Administrator from Emily C. Schilling, Holland & Hart. May 6, 2026.

between May 7, 2024, and May 7, 2026, these wells were allowed to route the associated gas through a CVS to a flare or control device achieving at least 95.0 percent methane and VOC reduction, provided the owner and/or operator demonstrated that the work practice standard options discussed above were technically infeasible. For wells that commenced construction, were modified, or were reconstructed between December 6, 2022, and May 7, 2024, the March 2024 Final Rule allowed operators to route the associated gas through a CVS to a flare or control device achieving at least 95.0 percent methane and VOC reduction on a routine basis, provided that the owner or operator documented and certified that compliance with the work practice standards was technically infeasible. Since May 7, 2026, all oil wells subject to NSPS OOOOb that were constructed, reconstructed, or modified after May 7, 2024, have been required to route their associated gas to a gas gathering line or collection system leading to a sales line, recover the associated gas and use it as an onsite fuel source or other beneficial use, or recover the associated gas and reinject it into a well, or, under specific scenarios, are allowed to temporarily flare emissions.[290, 291]

One industry representative provided production and operational details describing their ongoing efforts to comply with the March 2024 Final Rule NSPS OOOOb requirements.[292] They reported operating 65 wells in an extensional area of the Williston Basin in North Dakota. Of these, sixteen (16) of their wells began construction before May 7, 2022, and are not subject to the NSPS OOOOb's associated gas requirements. Twenty-nine (29) of their wells began construction between May 8, 2022, and May 7, 2024, and, as the industry letter suggests, have the option to comply with the NSPS OOOOb's associated gas requirements by routing to a control device provided

[290] 40 CFR 60.5377b(a).
[291] 40 CFR 60.5377b(d)(1)–(4).
[292] KODA Resources Operating LLC (KODA) (2026). Letter Re: Example of its North Dakota development in support of additional clarifications regarding the associated gas flaring provisions at 40 C.F.R. § 60.5377b. May 5, 2026.

there is a valid technical infeasibility determination. They further explained that fifteen (15) are delineation wells drilled to determine the boundary of the field or producing reservoir and are therefore not subject to NSPS OOOOb's associated natural gas requirements. They concluded by reporting that five (5) of their wells are development wells drilled after May 7, 2024, and are subject to the flaring prohibitions in 40 CFR 60.5377b(b).

The industry representative stated that they do not yet have access to a gas gathering line or collection system to capture 100 percent of the associated gas from their oil wells.[293] According to their example, they began discussions with third-party midstream companies in 2019. At the time, they noted that they had only drilled two initial wells and had insufficient natural gas volumes or a proved drilling inventory to generate interest from midstream companies. As such, they constructed a centralized facility to gather and process natural gas as an interim measure until a third-party solution was feasible. They indicated that they continued to work with multiple third-party midstream companies to design and scope a midstream project to capture 100 percent of their natural gas.

By 2023, the industry representative had contracted a dedicated drilling rig that substantially increased production volumes. They reported that the initial project scopes indicated a much smaller project scale, requiring low pressure gathering lines connected into existing infrastructure with an estimated in-service timeline of more than 6 months. However, as their drilling program continued to produce successful results and further delineate the field, other producers began shifting development plans towards their acreage. They reported that many of these producers' acreage was positioned along existing legacy pipeline gathering systems and were already contractually connected to

[293] KODA Resources Operating LLC (KODA) (2026). Letter Re: Example of its North Dakota development in support of additional clarifications regarding the associated gas flaring provisions at 40 C.F.R. § 60.5377b. May 5, 2026.

the midstream providers with whom the industry representative had been negotiating. As a result, existing midstream capacity was consumed. Between 2023 and 2024, the scope of their operations expanded substantially, increasing from and after engagement with several midstream companies. The owner identified a midstream company that specializes in gathering stranded associated natural gas. In 2025, they pre-funded engineering work while working to finalize a gas gathering system contract that would capture 100 percent of their produced associated natural gas. During this period, the operator also doubled the capacity across their gas gathering system and central facility to increase natural gas capture. In total, the expanded project will take 18 months to be in-service, rather than the 6-month timeframe previously contemplated when a low-pressure option was under consideration. The 18-month timeline is driven by both regulatory components (approximately 7-10 months for the cross-border pipeline) and the long lead-time needed for compression and plant expansion components, with delivery times being pushed out due to supply chain constraints. This industry representative asserted that if some percentage of their operations' associated natural gas cannot be flared, they may be forced to shut-in production, amounting to an estimated impact of up to $500 million and the potential delay or cancellation of a $75 million transboundary midstream infrastructure project which requires ongoing production to remain financially viable.

Another example highlighted by a law firm representing several oil and natural gas production companies involves situations where a production company drills wells in a previously undeveloped area 25 miles or more from any gathering flow pipeline or sales pipeline.[294] While the wells produce oil and associated gas in paying quantities, initially, when there are only a few wells, no midstream gas gathering company will commit to

[294] Holland & Hart. (2026). Letter Re: May 1, 2026, Guidance and April 30, 2026, Memorandum: Clarification of Regulatory Provisions Concerning Limits on Flaring Associated Gas for New Oil Wells. Letter to Aaron Szabo, OAR Assistant Administrator from Emily C. Schilling, Holland & Hart. May 6, 2026.

construct a pipeline to them to take the gas. In this example, the production company drilled additional wells, while necessarily flaring the associated gas, and ultimately generated enough volume of gas to entice a midstream gas gathering company to build a gathering flow pipeline or a sales pipeline to the wells to collect the gas. However, the pipeline construction will not be completed for 18 to 24 months. As such, the production company's only options during this period are to flare the associated gas or shut-in their oil wells.

d. Areas With No Proximity to Existing or Planned Gas Gathering Line or Collection System

Industry representatives also provided examples of instances where an owner or operator does not have access to a gas gathering line or collection system for reasons beyond their control, including: (1) wells located in extensional or frontier development areas where no third-party gathering connection exists; (2) areas where third-party midstream operators have permanently exited; or (3) situations where existing third-party infrastructure has failed and economic conditions do not support replacement.[295,296]

Considering the associated gas examples where temporary flaring would be needed until operators can route associated gas to a gas gathering line or collection system under development (see section III.J.2.b of this preamble), those examples also illustrate circumstances in which owners and operators in existence may not produce enough associated gas to attract a midstream gas gathering company to invest in the infrastructure to capture that gas. Under the March 2024 Final Rule provisions, operators

---

[295] Continental Resources (2026b). Re: Standards of Performance for Crude Oil and Natural Gas Facilities, 40 C.F.R. Part 60, Subpart OOOOb: Supplemental Operational Scenarios and Conceptual Framing in Support of Continental Resources' April 23, 2026, Letter Requesting Reconsideration of the BSER for Associated Gas and the Technical Infeasibility Demonstration Provisions in 40C.F.R. § 60.5377b. June 16, 2026.

[296] Kraken Oil and Gas Partners LLC (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 24, 2026.

in this situation would be unable to drill more wells to increase gas volumes to a level that would justify midstream gas gathering company investment in the necessary infrastructure. This scenario leaves owners and operators with no option but to flare the associated gas from existing wells or shut-in the wells.

One industry representative elaborated that third-party midstream operators may permanently exit a region, cease maintenance of a gathering system, or decline to repair damaged infrastructure when the economics no longer support continued operation.[297]According to the industry representative, this is most common in mature production areas where midstream throughput has declined, and at remote facilities where the cost of maintaining infrastructure exceeds the midstream operator's expected return. When this occurs, the upstream operator's wells are left without takeaway through no fault of the upstream operator and through circumstances outside the operator's control. They added that the gas becomes stranded not because the well changed, but because the midstream economics changed. In response, they noted that the operator's available options are limited: flare the stranded portion of associated gas to maintain oil production; attempt to build replacement gathering at a cost that is rarely economic; or shut-in the well.

Another reason provided by industry representatives where routing associated gas to an existing gas gathering line or collection system is not a viable option includes when it is economically infeasible to route associated gas to a sales line or use it onsite. This can occur, for example, when a mature well's production has declined to the point where

[297] Continental Resources (2026b). Re: Standards of Performance for Crude Oil and Natural Gas Facilities, 40 C.F.R. Part 60, Subpart OOOOb: Supplemental Operational Scenarios and Conceptual Framing in Support of Continental Resources' April 23, 2026, Letter Requesting Reconsideration of the BSER for Associated Gas and the Technical Infeasibility Demonstration Provisions in 40C.F.R. § 60.5377b. June 16, 2026.

routing to a sales line or onsite use is no longer viable.[298]

The EPA agrees with industry representatives' discussion and information related to the associated gas provisions and understands that, under the current structure of the provisions in NSPS OOOOb and EG OOOOc, circumstances could arise in which active wells may face the choice of shutting in and ceasing production to not violate the standards or to operate in violation of the standards. As discussed in Section III.J.2, industry representatives requested the EPA entirely revisit the previous BSER determination for the associated gas provisions. They raised concerns indicating that the current BSER for associated gas may not be appropriate.

3. EPA Considerations and Proposed Action

a. Revisions to BSER

The EPA is proposing to revise BSER to routing associated gas through a CVS to a control device or flare that achieves 95 percent reduction in emissions or greater. This section discusses the Agency's proposal that the previous BSER determination of routing associated gas to a sales line is not BSER, followed by a discussion of the proposed BSER determination for associated gas.

i. Routing Associated Gas to a Sales Line is Not BSER

The EPA is proposing that routing associated gas to a sales line may no longer be included as a viable control option in the BSER analysis. The BSER analysis conducted for this control option in the March 2024 Final Rule included several key assumptions, predictions, and foundational underpinnings that recent information has shown are not accurate. New facts significantly call into question the achievability of this control option. Further, the control option too heavily relies on actions of third parties that

[298] Continental Resources (2026b). Re: Standards of Performance for Crude Oil and Natural Gas Facilities, 40 C.F.R. Part 60, Subpart OOOOb: Supplemental Operational Scenarios and Conceptual Framing in Support of Continental Resources' April 23, 2026, Letter Requesting Reconsideration of the BSER for Associated Gas and the Technical Infeasibility Demonstration Provisions in 40C.F.R. § 60.5377b. June 16, 2026.

owners and operators (those subject to the EPA's regulations) have no control over.

In the March 2024 Final Rule, the EPA anticipated that "owners planning on drilling new wells in the future have the ability to plan ahead to ensure that the associated gas is routed to a sales line."[299] But this statement was based on predictions about the industry that have not come to fruition and thus inaccurate. In that rulemaking, the EPA cited to some States that have essentially banned routine flaring of associated gas, and to a voluntary commitment from some companies to end routine flaring by 2030.[300] However, these States and companies do not represent the entire industry that the EPA is charged with regulating. Further, neither these state regulations nor the voluntary commitments are governed by (required by) the CAA, so their existence does not necessarily mean that similar requirements are permissible under the CAA. As discussed in sections III.J.2.a through III.J.2.d of this preamble, some companies in certain parts of the country cannot route their associated gas to a sales line, even with advanced planning.

While the EPA was aware of these potential issues, in the 2024 Final Rule, the Agency made assumptions about the industry that presumed there would be timely and sufficient sales line infrastructure development. However, new information (see sections III.J.2.c and d of this preamble) since promulgation of the March 2024 Final rule shows that the EPA's assumptions have not been borne out by real-world industry development.

In the EPA's TSD for the March 2024 Final Rule, the Agency identified several "challenges" with the control option of routing to a sales line.[301] First, in 2024 the Agency knew that in many places "pipeline infrastructure is not in place to transport captured gas away from the wells."[302] The EPA assumed that pipeline infrastructure and

---

[299] 89 FR 16945 (March 8, 2024).
[300] 89 FR 16944 (March 8, 2024).
[301] https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-3988
[302] U.S. EPA. (2023b). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Background Technical Support Document (TSD) for the Final New Source Performance Standards. Chapter 4. (Associated Gas). Section 4.3.1. November 2023.

capacity would keep pace with new oil wells such that all new oil wells would have sufficient pipeline availability to route all of their associated gas into a sales line. Second, the EPA acknowledged that "[b]uilding a gathering pipeline system and associated compressors is a large capital expense and requires permits and negotiations with landowners."[303] Third, the EPA recognized that "oil wells are drilled by exploration and production companies; to tie into a gathering pipeline system would require coordination with midstream gas companies and would depend on multiple variables of the associated gas produced from the oil well."[304] Taken together, the second and third points acknowledge that owners and operators of wells (the regulated entity) do not control the necessary midstream infrastructure and that the regulated party, therefore, necessarily depends on actions of outside parties (third parties) to achieve compliance, and that completing all steps to achieve compliance is very complicated and expensive. Despite all of these identified obstacles, the Agency still finalized routing to sales as the BSER based on the general idea that owners and operators would find a way to comply; that "opportunities exist for advance planning" and that "owners and operators of newly drilled wells have the flexibility to plan and coordinate the construction of gas gathering systems even over extended distances."[305, 306]

Regarding the cost of the control option, the EPA likewise made assumptions regarding the availability of infrastructure. For example, in the March 2024 Final Rule, the EPA cited the 2021 Proposal, stating that it was assumed "that in situations where gas sales line infrastructure is available, there is minimal cost to owners and operators to route the associated gas to the sales line."[307] As such, even in the cost assessment aspect of the BSER analysis, the EPA was assuming that gas sales line infrastructure was

---

[303] *Id.*
[304] *Id.*
[305] 89 FR 16944 (March 8, 2024).
[306] 89 FR 16942 (March 8, 2024).
[307] 89 FR 16940 (March 8, 2024) (quoting 86 FR 63237 (November 15, 2021)).

available and accessible, which the evidence now shows is not the case in all areas of the country.

Recent information (see section III.J.2.c and d of this preamble) from industry stakeholders has shown that even with advanced planning and flexibility to coordinate with owners and operators of gas gathering systems (*i.e.*, third parties that are not regulated by the EPA in this action), some owners and operators of oil wells cannot route their associated gas into a sales line. For example, the Koda letter (explained in more detail above in section III.J.2.c) outlines one company's planning efforts that resulted in not being able to route all of their gas into sales lines.[308]

The ability to route associated gas to a sales line depends entirely on third-party gathering and midstream companies (*i.e.*, companies that are not part of the regulated upstream category). These companies determine when and where infrastructure is built, the capacity of that infrastructure, and which wells they will accept gas from—decisions generally outside the control of oil well owners and operators. Even where a connection exists, gathering and midstream companies may decide to stop accepting gas at any time. The EPA's 2024 TSD focused on state regulations in Colorado, New Mexico, Utah, and Wyoming to support making route to sales the standard.[309] But recent information from industry stakeholders discusses problems for sources in North Dakota, South Dakota, Montana, Texas, Oklahoma, and other states that EPA did not consider deeply in the context of the March 2024 Final Rule. Other information from industry stakeholders (explained in more detail above in section III.J.2) further shows that the assumptions regarding the availability of gas gathering and sales lines that underpinned the BSER

[308] KODA Resources Operating LLC (KODA) (2026). Letter Re: Example of its North Dakota development in support of additional clarifications regarding the associated gas flaring provisions at 40 C.F.R. § 60.5377b. May 5, 2026.

[309] U.S. EPA. (2023b). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Background Technical Support Document (TSD) for the Final New Source Performance Standards. Chapter 4. (Associated Gas). Section 4.2. November 2023.

determination in the March 2024 Final Rule have not borne out as the EPA originally predicted.[310] In these situation where a gathering or sales lines remains unavailable despite advanced planning and coordination, companies must shut down their operators to avoid noncompliance. While the March 2024 Final Rule stated that circumstances "beyond the control of the owner or operator" should not result in shut-ins, the possibility of shutting in an oil well is exactly what some owners and operators are now facing.[311] Since timely availability of sales line infrastructure for all new oil wells was the key assumption underpinning the 2024 BSER determination, and infrastructure availability is still limited, at least in certain areas, route to sales can no longer be considered as a universally available and technically viable control option.

Moreover, since promulgation of the March 2024 Final Rule, the EPA has realized that owners and operators are very likely invoking one of several flaring exemptions more often than originally anticipated. After finalizing the March 2024 Final Rule, the EPA soon realized that the rule had problems regarding certain flaring exemptions and we granted reconsideration on two technical issues, one of which was "temporary flaring provisions for associated gas in certain situations."[312] Based on that reconsideration, the EPA amended some of the temporary flaring provisions because they were too limiting.[313] In short, the EPA realized that sources needed more time to flare that originally anticipated. Then, in April 2026, the EPA issued a guidance memorandum

---

[310] Continental Resources (2026b). Re: Standards of Performance for Crude Oil and Natural Gas Facilities, 40 C.F.R. Part 60, Subpart OOOOb: Supplemental Operational Scenarios and Conceptual Framing in Support of Continental Resources' April 23, 2026, Letter Requesting Reconsideration of the BSER for Associated Gas and the Technical Infeasibility Demonstration Provisions in 40C.F.R. § 60.5377b. June 16, 2026; Kraken Oil and Gas Partners LLC (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 24, 2026; Holland & Hart. (2026). Letter Re: May 1, 2026, Guidance and April 30, 2026, Memorandum: Clarification of Regulatory Provisions Concerning Limits on Flaring Associated Gas for New Oil Wells. Letter to Aaron Szabo, OAR Assistant Administrator from Emily C. Schilling, Holland & Hart. May 6, 2026.
[311] 89 FR 16949 (March 8, 2024).
[312] https://www.epa.gov/system/files/documents/2024-05/letter-to-api-and-apx.-5.6.24-signed_1.pdf.
[313] 91 FR 18056 (April 9, 2026).

to again address an issue with temporary flaring of associated gas because of the large number of sources invoking the rule's exceptions to flare their gas instead of routing it into a sales line.[314] The industry letters that prompted the guidance memorandum detailed many situations beyond the control of the owner/operator that resulted in not being able to route the oil well's associated gas into a sales line.[315] The frequent and widespread flaring of associated gas in the context of a requirement that purports to prohibit flaring demonstrates that the EPA's previous BSER analysis was flawed. The fact that oil wells must so often rely on these flaring exemptions calls into question whether routing to a sales line can be considered the BSER, and it calls into question the EPA's previous claims that the BSER resulted in 100% emission reduction.

The EPA previously assumed that all associated gas would be routed into a sales line at all times, but in reality, sources often flare under the current rule's exceptions. As such, it is very likely that the EPA overestimated the true emission reduction from routing to a sales line and thus made a decision based on an inaccurate BSER analysis that does not reflect how these sources actually operate in the real world. In other words, the difference between the "100 percent capture" via routing to a sales line is actually lower than that and closer to 95 percent which is the efficiency from flaring. In reality, many sources are still flaring because they cannot route all of their associated gas to a sales line all of the time.

Lastly, with regard to costs, the EPA's BSER analysis did not account for the added costs of buying, installing, and operating a flare to comply with the temporary flaring exceptions, nor did the EPA assume that flares already onsite for other purposes could accept the increase gas flow during these periods. Since temporary flaring is

---

[314] U.S. EPA (2026). Memorandum. Clarification of Regulatory Provisions Concerning Limits on Flaring Associated Gas for New Oil Wells. From Aaron Szabo, OAR Assistant Administrator to Regional Administrators, 1-10. April 30, 2026. Available at: https://www.epa.gov/system/files/documents/2026-04/signed_final_o-g-associated-gas-memo_4-30-26_0.pdf.

[315] See letters here: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/implementation-oil-and-natural-gas-air.

needed for the route to sales standard, many (if not all) owners and operators routing to a sales line need to purchase, install, and maintain a flare. The EPA did not consider this cost. As such, the 2024 BSER analysis underestimated the true costs of the current standard and overestimated emission reductions; in reality, routing to a sales line has proven less effective and more costly than the EPA previously anticipated.

Next, the March 2024 Final Rule reflected an overbroad reading of CAA section 111 that did not recognize or account for the scale of the infrastructure required for compliance, including the difference between systems that sources can apply to meet the standards that apply to them and systems that require significant investment and performance by third parties. Owners and operators of oil wells subject to the "route to sales line" requirements are dependent on third parties to develop and operate virtually all the components of the sales line. Many owners and operators of upstream facilities do not own or operate the midstream pipelines that are required to implement the standard for associated gas. Companies cannot compel midstream operators to expand their infrastructure so that they can accept additional natural gas. This system differs from the types of equipment the Agency has historically selected as BSER. All relevant third parties would need to timely complete their components of the infrastructure across large geographic areas for the owners and operators to be able to comply with the standard by the time the well begins producing, and thereafter, owners and operators must rely on the continued cooperation and operation of these third parties. Upon further consideration, the EPA concludes that the scale of the necessary infrastructure, including the necessary involvement of third parties nationwide, is different in kind from control measures historically considered under CAA section 111 and thus not an allowable form of BSER.

Put another way, the EPA has, upon further review, determined that the novelty of a BSER predicated on widespread infrastructure developed and operated by third parties warns strongly against its selection. Much of the necessary gathering and sales line

infrastructure requires the involvement, both for initial development and ongoing performance, of external third parties over whom the owners and operators of regulated facilities have limited, if any, control. For example, the EPA correctly explained in the TSD for the March 2024 Final Rule that routing gas to a sales line entails third parties and depends on "multiple variables", including permitting and "negotiating with landowners."[316] It is possible that in some instances a landowner might simply refuse to allow any gas pipeline to cross their land. Further, a midstream company (not the regulated owner/operator) would very likely be the entity planning, contracting, and maintaining the necessary sales line and be the third party that controls which owner/operators may route gas into their sales line. This situation is not within the oil well owner's or operator's control. Moreover, natural resources such as oil reservoirs only occur in certain geographic areas of the country. Owners and operators do not get to pick and choose where the oil is located; they must develop their regulated source where the oil exists and in some cases the oil exists in locations where these variables prove unworkable. In some cases, new oil wells are far from the existing infrastructure that is needed to move the gas to a sales line. In other cases, the oil wells may be located in proximity to an existing sales line but the downstream infrastructure is not capable of handling new volumes of natural gas. The owner/operator of the sales line may not be able to accept new gas for a variety of reasons. For instance, the pressure in the existing sales line pipeline may be too great for the new oil wells to be able to inject their gas into the pipeline much of the time, or the natural gas processing plant may not have the capacity to accept the additional gas. Even after an oil well site is connected to a sales line, there may be multiple reasons why the pipeline is unable to accept the gas. This

[316] U.S. EPA. (2023b). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Background Technical Support Document (TSD) for the Final New Source Performance Standards. Chapter 4. (Associated Gas). November 2023.

could be due to the quality of the natural gas at the oil well site; or similarly, it could be due to the quality of natural gas at neighboring well sites owned by other companies, resulting in a situation where the midstream operator is unwilling to accept any natural gas in the area until the source of the poor-quality natural gas is identified. There can also be bottlenecks at some point in the pipeline network that prevent the midstream operators from accepting all of the natural gas from a well site.

A BSER based on routing associated gas to a sales line thus requires involvement, at multiple steps, of a complex web of different entities across a wide range of disciplines, some of whom may not be part of the regulated source category, or even the broader industry of which it is part, *i.e.,* the oil and gas industry. As just one example, the BSER could entail several different government permitting offices at the local (town, city, and/or county), State and/or federal (other than the EPA) level, multiple individual landowners, and a midstream gas gathering and sales company. The implication is that these third parties are not subject to the same regulatory impetus as the owner or operator of an oil well that would be subject to requirements under the March 2024 Final Rule. The scale of the ancillary infrastructure required to support implementation of the standard and the multitude of parties outside of an owner or operator's control at multiple steps of the process that are necessary to successfully design, permit, construct, test, operate, and maintain a system to route associated gas to a sales line makes it unreasonable to base federally enforceable requirements on the presumption of a best-case scenario for implementation when tardy- or non-performance by a single party has the potential to cause or exacerbate delays that ripple through the deployment of the entire system upon which the standard relies. All this compounds the likelihood of not having the necessary infrastructure in place when oil production begins, which further supports the unreasonableness of the current standard.

The tenuousness of timely compliance given the scope of the requisite

infrastructure for routing associated gas to a sales line, coupled with the novelty of the standard and the need for a large number of third parties, is especially apparent when it is contrasted with an air pollution control technology that has been in widespread use in the oil and gas sector for decades: combustion devices (flares), a control technology that does not rely on extensive pipeline infrastructure. It simply requires the owner/operator to purchase, install, and operate the device on-site. While that process does in some ways involve third parties (for example, to build and, perhaps, install the device), the industry has a long history of using these deceives such that completing the request steps is not overly complex or unreasonably dependent upon novel third party interactions.

The EPA acknowledges that some owners/operators of oil wells also own and operate their own midstream sales line infrastructure such that these characterizations of heavy reliance on third-party involvement may not be accurate for all sources (although there may be requirements that the midstream company cannot give preference to an upstream company owned by the same parent company). However, the EPA understands this is not often the situation and that in most cases the oil well site owner/operator has little to no control over the sales line infrastructure. The EPA is soliciting comment and information on the proportion of owners and operators that also own or operate their own midstream sales line infrastructure. (Question III.9a)

To be sure, many oil wells can and do route at least some of their associated gas to a sales line. However, in those instances, routing to sales has not been required by federal regulation under enforceable timelines or at a similar nationwide scale, meaning that any non-performance by third parties has not resulted in noncompliance with federally enforceable obligations.

In reaching these conclusions, the EPA notes that CAA section 111 anticipates analyses and regulatory requirements that turn on actions by the regulated source. Pursuant to CAA section 111(a)(1), the Agency must promulgate standards that "reflec[t]

the degree of emission limitation achievable through the *application* of the [BSER],” and the resulting emission standards apply, in turn, to the regulated source. Consistent with the EPA's historical understanding, this language is most naturally read as tying the BSER to results that are achievable through the source's application of the selected control technology. While sources commonly rely on third parties in the normal operation of their business, the extensive infrastructure requirements for routing to a sales line, coupled with the high level of dependence on third parties, undermines the ability of sources to achieve the emission standards. If any third-party provider responsible for any of the many links in the sales line infrastructure chain fails to develop the necessary infrastructure in a particular area, is delayed in such development for any reason, or ceases operation for any reason, the source would no longer be able to comply. These circumstances are different in kind from other BSERs that entail substantially less reliance on third-party infrastructure.

The EPA is thus finding that the March 2024 Final Rule erred by not considering the extent of the ancillary infrastructure and reliance on third parties needed for routing associated gas to a sales line to be deployable at scale.

ii. Proposed BSER Determination

Given the proposed determination that routing to a sales line is not BSER, the EPA evaluated potential BSER options for associated gas from oil wells. The options considered include non-flaring technologies, specifically those currently allowed as alternatives to routing to a sales line, as well as routing gas to a flare/control device to achieve either a 95 percent reduction or a 98 percent reduction (see U.S. EPA. (2026). Technical Memorandum. Analysis of Potential BSER Options for Associated Gas).

The category of non-flaring BSER options considered consists of the non-flaring techniques specified in the standards contained in 40 CFR 60.5377b(a)(2), (3), and (4) of NSPS OOOOb and the presumptive standards contained in 40 CFR 60.5391c(a)(2), (3),

and (4) of EG OOOOc These techniques include the following:

- Recovering associated gas from the separator and using the recovered gas as an onsite fuel source
- Recovering associated gas from the separator and reinjecting the recovered gas into the well or injecting the recovered gas into another well
- Recovering associated gas from the separator and using the recovered gas for another beneficial purpose that would otherwise be served by a purchased fuel or raw material.

Each of these options are discussed below.

Use as an Onsite Fuel Source

The use of associated gas from an oil well as an onsite fuel source is only technically feasible under certain operating conditions. This control option is generally most feasible where gas volumes and pressures are sufficiently stable to support operation of generators or heaters, and where gas composition is compatible with such use, either directly or with limited conditioning. Onsite use may be particularly advantageous when there is a consistent demand for power or heat, enabling offset of diesel or grid electricity consumption. However, the EPA recognizes that not every oil well is suitable for recovering and using associated gas onsite because technical limitations often make it impractical. In many instances, site-specific conditions preclude its implementation. For example, associated gas production may be intermittent, variable, or of insufficient quantity to support stable operation of generators, heaters, or processing equipment. In addition, associated gas may contain contaminants such as hydrogen sulfide (H_2S), carbon dioxide (CO_2), water vapor, or heavy hydrocarbons, which may necessitate extensive conditioning to avoid corrosion, engine damage, or unsafe combustion. Additionally, the intermittent nature of production, especially in unconventional reservoirs, can lead to unreliable or inconsistent gas supply, which

hinders the functioning of fuel systems that require steady input. Further, some existing well sites may lack the physical space or infrastructure needed to safely handle, treat, and distribute gas to onsite equipment. Lastly, some sites where onsite use is technically feasible may only be able to use a portion of the associated gas that the oil well produces due to the demand that exists on that site for such fuels. Sites that do not have sufficient onsite demand for all of their associated gas would then have remaining gas that they could not use onsite. While the use of associated gas as an onsite fuel source may constitute a feasible emissions control strategy at some facilities, it is not widely practicable across the affected source category.

Accordingly, while using associated gas as an onsite fuel source is adequately demonstrated, it is not achievable across the country.

Reinject the Recovered Gas into the Well or Inject the Recovered Gas into Another Well

Reinjecting recovered associated gas into the producing well or injecting it into another nearby well may be an attractive option because it can allow operators to avoid flaring or venting while also enhancing reservoir performance. By returning the gas underground, producers may be able to maintain reservoir pressure, which can improve oil recovery and extend the productive life of the field. This approach may also reduce emissions, eliminate the need for immediate gas processing or transportation infrastructure, and offer flexibility by storing the gas for future use when market conditions or infrastructure availability are more favorable. However, reinjection is not technologically feasible for every oil well because it requires reservoirs with the right geological and pressure characteristics to safely accept additional gas. Some geological formations cannot accommodate more gas via reinjection without risking loss of reservoir integrity, unwanted fluid migration, or disruption of natural flow patterns. In certain wells, gas reinjection may interfere with oil displacement mechanisms or alter fluid

composition in ways that reduce recovery efficiency. Additionally, not all fields have nearby wells or formations suitable for injection, and some reservoirs may lack the pressure, permeability, or structural stability needed to retain injected gas without risking leakage or contamination of other subsurface zones.

Considering the same adequately demonstrated and achievable criteria for BSER discussed above, the EPA concludes that reinjecting the recovered gas into the well or inject the recovered gas into another well is not achievable across the country.

Recover Associated Gas and Use it for Another Purpose Displacing Purchased Fuel or Raw Material Consumption

Using the recovered gas for another useful purpose that a purchased fuel or raw material serves as a generic "catch-all" provision that does not provide sufficient specificity for establishing BSER. In the December 2022 Supplemental Proposal, the EPA discussed examples of potential "other useful purpose" options to utilize associated gas and avoid venting or flaring, namely methane pyrolysis and condensing the gas and transporting it to other sites for use.[317] The December 2022 Supplemental Proposal also discussed technologies to convert gas to liquid and the production of liquified natural gas.

In response to the December 2022 Supplemental Proposal, commenters argued that the technologies identified by the EPA were not broadly practical because they were unproven, not commercially viable, or not technically feasible at many oil-well sites. For example, one company reported deploying a portable cryogenic unit to convert the associated gas to natural gas liquids, but the unit did not perform and was uneconomic.[318] Because feasibility varies widely by location and technology maturity, commenters urged

[317] 7 FR 74702, 74779 (December 6, 2022).
[318] Continental Resources (2026a). Letter to the EPA Administrator. Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Request for EPA's reconsideration of the BSER for associated gas and the requirements governing technical infeasibility determinations under in 40 C.F.R. § 60.5377b. April 23, 2026.

the EPA not to include a fixed list of beneficial uses.[319] In the March 2024 Final Rule, the Agency agreed with the commenters and removed all mentions of these, and other, specific other uses.

Therefore, the EPA concludes that neither the generic category of "another useful purpose that a purchased fuel or raw material would serve," or specific unproven emerging technologies identified, qualify as BSER.

ii. Routing to a Flare or Control Device

The EPA considered two types of flaring options (which includes other control devices): flares or devices that control 95 percent reduction and those that achieve 98 percent reduction. These options are described below.

Flares and Devices that Achieve 95 Percent Reduction

Associated gas can be routed to a flare or another control device capable of achieving 95 percent reduction in emissions. Achieving this level of performance depends on having a consistently lit pilot flame, sufficient combustion temperature, appropriate gas flow rates, and effective mixing of air and hydrocarbons so that the gas fully burns rather than escapes un-combusted. Routing to a flare is an adequately demonstrated technology that is applicable across the country.

In the 2022 Supplemental Proposal Technical Support Document (TSD),[320] the EPA determined that representative associated gas emissions from an oil well, whether new or existing, are 344 tpy methane and 96 tpy VOC, if uncontrolled. The EPA also presented flare costs estimates of $100,579 in capital costs and $36,000 in annual costs (including capital recovery and operation and maintenance). After updating these costs to a 2024 base year, the estimated total annual cost of a flare is $47,411. On that basis, the

[319] 89 FR 16820, 16950 (March 8, 2024)

[320] U.S. EPA. (2022). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Supplemental Background Technical Support Document (TSD) for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG); Chapter 6 (Associated Gas). October 2022.

cost effectiveness is estimated at $145 per ton of methane reduced and $523 per ton of VOC reduced for the representative well. These values are in the range that the Agency has considered reasonable in the past.

Flare and Devices that Achieve 98 Percent Reduction

Flares can also achieve 98 percent destruction efficiency when they are properly designed, operated, and maintained. As with a flare designed to achieve 95 percent reduction, performance at a 98 percent reduction also depends on having a consistently lit pilot flame, adequate combustion temperature, favorable gas flow rates, and effective mixing of air and hydrocarbons. However, achieving this higher efficiency requires even more stable conditions—such as steady pressure, wind protection, and appropriate flare tip design—that help ensure complete combustion and enable flares to reach or exceed 98 percent emission reduction under ideal operating environments.

In the November 2021 Proposed Rule, the EPA indicated that combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice in the oil and gas industry due to factors such as variability of field conditions. The EPA specifically requested comment on the potential to require more rigorous monitoring requirements for the oil and natural gas industry to ensure 98 percent reduction, such as those contained in NESHAP for the Petroleum Refinery Sector, 40 CFR part 63, subpart CC.[321] The EPA received comments on this solicitation stating that flares can be designed to achieve 98 percent control efficiency, but that variability in gas flow, pressure, and quality would present challenges to achieving 98 percent control efficiency in the oil and natural gas industry. While the EPA did not determine whether 98 percent control efficiency flares were achievable, the Agency did perform a cost analysis of these flares and compared it to the impacts of a 95 percent reduction flare. The EPA concluded "that the additional reduction is not cost effective and would

[321] 86 FR 63110, 63246 (November 15, 2021).

therefore not represent the BSER for affected sources requiring an emissions reduction through the use of a pollution control device."[322]

The EPA performed this previous analysis primarily for storage vessels, which typically have lower emission levels than our representative associated gas well. Therefore, the EPA evaluated the incremental costs and emission reductions between 95 percent reduction and 98 percent reduction.

In the previous analysis,[323] the EPA estimated the capital cost for a flare and all the monitoring equipment that would be required to achieve a 98 percent reduction to be $430,000 (2019$). Updating this estimate to mid-year 2024$ results in an estimated capital cost of $565,618.

The EPA further estimated that the annual costs would be 2.7 times higher than those for a flare achieving 95 percent reduction. Applying this factor to the estimated annual cost for a 95 percent flare cited above ($47,411) results in an estimated annual cost of $128,011. This represents an incremental annual cost of $80,599. The incremental emissions reduction for the representative associated gas well (with baseline emissions of 343.6 tpy methane and 95.5 tpy VOC to install flares with 98 percent instead of 95 percent reduction would be 10.8 tpy methane and 2.86 tpy VOC. Accordingly, the resulting incremental cost effectiveness values are $7,819 per additional ton of methane reduced and $28,132 per ton of additional VOC reduced. Both of these values exceed the range the EPA has historically considered reasonable. For these reasons, and for the reasons stated in the December 2022 Supplemental Proposal, requiring associated gas emissions to be reduced by 98 percent is not the BSER.

---

[322] 87 FR 74702,74794 (December 6, 2022).

[323] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). U.S. Environmental Protection Agency, Office of Air and Radiation Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina. October 2021.

iii. Proposed BSER Determination

Based on this evaluation of all technically viable options for managing associated gas from oil wells, the EPA concludes that neither onsite use, reinjection, nor other beneficial-use technologies satisfy the statutory criteria of being both adequately demonstrated and achievable. Emerging technologies likewise cannot serve as BSER because they are not yet sufficiently proven or commercially practical. In contrast, routing associated gas to a flare or other control device capable of achieving a 95-percent reduction in methane and VOC emissions is an adequately demonstrated, widely applicable, and cost-effective system, with performance and cost-effectiveness values that fall within ranges the Agency has historically considered reasonable. Additional analysis shows that a 98 percent reduction is potentially not achievable in field conditions and would impose incremental costs exceeding levels the Agency has found reasonable. Therefore, the record supports a conclusion that a 95-percent reduction in methane and VOC emissions represents BSER for associated gas.

iv. Proposed Standards and Presumptive Standards for Associated Gas

Therefore, for associated gas, the EPA is proposing that the associated gas must be routed through a closed vent system to a control device that achieves 95 percent reduction in emissions or greater, or route through a closed vent system to a flare that meets the applicable flare requirements. The EPA is proposing that owners and operators would be free to utilize compliance methods that achieve even greater reductions, including capturing and routing to a sales line 100 percent of their associated gas or using 100 percent of their associated gas for another beneficial purpose. The EPA is also proposing that if a portion of the associated gas is routed to sales or used for another purpose, the remaining portion must comply with the 95 percent standard. For example, if a company could route 40 percent of their associated gas to a sales line or for another potential purpose, the company would need to route the other 60 percent to a control

device with a 95 percent reduction or to a flare.

b. Solicitation of Comment on Alternative to Revised BSER

The EPA is also seeking comment on an alternative approach which would maintain the current structure of the associated gas requirements (along with the BSER analysis from the March 2024 Final Rule) in both NSPS OOOOb and EG OOOOc while attempting to address the specific concerns raised by industry stakeholders through targeted regulatory amendments. (Question III.9b)

The EPA developed the 2024 BSER determination (*i.e.*, routing associated gas to a gathering or collection system to a sales line,) based on two proposals: the original November 2021 Proposal[324] and the December 2022 Supplemental Proposed Rule.[325] The Agency considered available information obtained prior to each of these proposals, as well as the information submitted to the EPA during the two separate public comment periods when developing the March 2024 Final Rule standards. The EPA solicits additional comments and requests additional information on whether and/or how keeping the existing structure of associated gas provisions but with added flexibilities, such as described below in Sections III.J.3.b.i and ii, could address typical issues for owners and operators attempting to route associated gas to a sales line but facing circumstances outside their control.

i. Temporary Flaring Allowances

As described in section III.J.2 of this preamble, industry representatives identified a number of situations where the temporary flaring allowances in 40 CFR 60.5377b(d)(3) are not sufficient, leaving operators faced with shutting in the wells or operating out of compliance. Many of these situations are beyond the control of the well owner and operator. The corresponding provisions in the EG model rule are 40 CFR 60.5391c(c)(3)

[324] 86 FR 63110 (November 15, 2021).
[325] 87 FR 74702 (December 6, 2022).

and (4).

The EPA understands that implementation of the rule has led to the identification of situations not originally anticipated. The Agency recognizes recent industry feedback that the current timelines for addressing midstream service interruptions and gas quality issues may be too short in some circumstances. As a result, the EPA solicits comments on whether revisions to existing provisions could offer necessary flexibilities to address industry concerns.

Specifically, the EPA solicits comment on allowing an extension of the temporary flaring durations under 40 CFR 60.5377b(d)(3) and (4) and 40 CFR 60.5391c(c)(3) and (4) per incident. Right now, the temporary flaring allowance for interruption in service in the NSPS at (d)(3) is limited to 30 days per incident, and the temporary flaring allowance for gas composition issues at (d)(4) is limited to 72 hours per incident. The EPA solicits comment on whether these timelines should be revised to be longer. For example, perhaps the temporary flaring allowance for interruption in service at (d)(3) should be revised to be 90 days per incident instead of 30, and/or the temporary flaring allowance for gas composition issues at (d)(4) should be 7 days instead of 3 (72 hours). The EPA solicits comments on what these timelines should be.

The Agency also solicits comment on whether and how to define "incident" for the purposes of 40 CFR 60.5377b(d) (3) and (4) as well as 40 CFR 60.5391c(c)(3) and (4). (Question III.9c) Further, the Agency solicits comment on if and how it should define the start of an "incident" for purposes of measuring the timelines in the regulations for 60.5377b(d)(3) and (4). One example could be to define the start of an incident as the moment an owner or operator receives a notification of interruption of service or gas composition issues and is unable to route their gas into a gas gathering line or collection system.

In correspondence with the industry, owners and operators did not offer specific

alternative durations needed to address these temporary interruption incidents. The EPA is requesting comment and supporting information regarding the typical durations of midstream service outages and what an appropriate and reasonable timeline would be for resolving gas quality issues. (Question III.9d) Additionally, the Agency is soliciting comment on whether an annual temporary flaring limit should be included and, if so, what a reasonable limit would be. (Question III.9e) EPA is considering whether the inclusion of a temporary flaring limit for a calendar year would result in owners or operators having to shut-in the well if more service interruptions or gas quality issues persist. If inclusion of an annual temporary flaring limit would cause issues, EPA is considering whether owners or operators would be allowed to utilize these recurring situations as part of their technical infeasibility determination and certification to enable compliance via routing the associated gas to a flare or control device achieving 95.0 percent emissions reduction.

At the same time, EPA is considering whether allowing for flaring of associated gas under circumstances where there are multiple temporary interruption incidents could be deemed temporary, *i.e.*, owners and operators could be required to cease flaring as soon as the service interruption or gas quality issue is resolved only to restart flaring at the start of the next incident. If extending temporary flaring duration, EPA would need to ensure that these provisions are used only as intended, the Agency could require notifications, and periodic records and reports for each temporary interruption incident. The EPA solicits comment on whether introducing appropriate notification, recordkeeping, and reporting requirements would serve as a robust guardrail to ensure that flaring remains a temporary practice.[326] The EPA is soliciting comment on whether it could require that an initial notification be submitted to the Agency as soon as an owner

[326] Given the deregulatory nature of this possible revision, the EPA anticipates that any burden associated with what the solicitation suggests would be minimal in comparison with the current burden.

or operator becomes aware of a temporary interruption incident that results in the need to flare, and if so, what documentation could be required to explain why no other compliance method under NSPS OOOOb or EG OOOOc is possible for controlling the associated gas. The Agency also solicits comment on whether to require an owner or operator submit a notification to the EPA upon resolution of the temporary interruption incident, and similarly, whether during the incident, the EPA should require periodic reports on the status of the temporary interruption incident and the steps being taken to resolve it or whether such notifications and periodic reports documenting these incidents should be required to be maintained as records. (Question III.9f) Additionally, the EPA requests comment on whether the Agency should require to include in annual reports information related to the temporary interruption incident (*i.e.*, when the temporary interruption incident started, circumstances related to the incident, and resolution status). The Agency is also soliciting comment on the appropriate frequency of periodic status reports related to the status of a temporary interruption incident, if commenters agree that EPA should require such reports. (Question III.9g)

ii. Oil Wells with Associated Gas That Do Not Have Access to Gathering Systems Or Do Not Have the Ability to Utilize 100 Percent of the Associated Gas in Accordance with 40 CFR 60.5377b(a)

For the March 2024 Final Rule, the EPA recognized that owners and operators of new wells commencing construction prior to May 7, 2024, would have already determined their location and made commitments prior to the knowledge of the requirements in the March 2024 Final NSPS OOOOb provisions. Therefore, they may not have the ability to route all associated gas produced to a sales line or use it for another purpose as required by 40 CFR 60.5377b(a). Therefore, the March 2024 Final Rule NSPS OOOOb requirements allow the routine flaring of associated gas from these wells, provided the owner or operator demonstrates and certifies that it is not technically

feasible to comply with any of the options in 40 CFR 60.5377b(a). The preamble to the March 2024 Final Rule included a robust discussion of the technical infeasibility determination, including numerous specific examples of potential reasons that could support such determination.[327]

The EPA assumed that owners and operators of wells commencing construction after the effective date of the March 2024 Final Rule would have adequate time to plan for compliance with one or more of the options in 40 CFR 60.5377b(a). The exception to this assumption applies to wells that commenced construction shortly after NSPS OOOOb was finalized. The Agency recognized that development plans may have been underway prior to the publication of the March 2024 Final Rule (even though they had not officially "commenced" construction), and that owners and operators in this group would need additional time for a sufficient phase-in period to adjust to the final standard, which differed from what the EPA had included in the December 2022 Supplemental Proposal. Therefore, the March 2024 Final Rule NSPS OOOOb requirements allowed owners and operators of wells that commenced construction after the final rule was effective to routinely flare for two years (until May 7, 2026) at which time they were required to comply with one or more of the options in 40 CFR 60.5377b(a).

Based on the information provided by industry representatives summarized in sections III.J.2.c and d of this preamble, the EPA acknowledges that the assumption that owners and operators of newly constructed wells could work out ways to comply with one or more of the options in 40 CFR 60.5377b(a) in all circumstances did not reflect the full range of operational scenarios that the industry encounters. Industry representatives have provided additional information and arguments that have better informed the Agency regarding details and complexities not previously considered. For example, wells for which construction was commenced between May 7, 2024, and May 7, 2026, may

[327] 89 FR 16888 (March 8, 2024).

have entered into agreements to connect to a gas gathering line or collection system, but construction of the system was not completed by the deadline, and the construction of these third-party systems was not under the control of the oil and gas well owner or operator. Also, the industry representatives pointed out the reality that third-party mid-stream companies are not likely to plan the construction of new gas gathering line or collection systems in an area before wells in that area are producing associated gas.[328, 329] Under the NSPS OOOOb requirements, however, new wells cannot operate unless they can either route all the associated gas to a gas gathering line or collection system to a sales line or use it for another purpose allowed in 40 CFR 60.5377b(a). The result is that potentially productive oil fields may go undeveloped.

A third situation that industry has brought to the EPA's attention involves wells that are connected to a gas gathering line or collection system but experience frequent and recurring interruptions in service.[330, 331, 332] As discussed in section III.J.3.a of this preamble, the Agency is requesting comment on extending the duration allowed for temporary flaring under 40 CFR 60.5377b(d)(3) and (4) and 40 CFR 60.5391c(c)(3) and (4). Specifically, EPA is requesting supporting information on what flaring allowance

---

[328] Continental Resources (2026a). Letter to the EPA Administrator. Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Request for EPA's reconsideration of the BSER for associated gas and the requirements governing technical infeasibility determinations under in 40 C.F.R. § 60.5377b. April 23, 2026.

[329] Holland & Hart. (2026). Letter Re: May 1, 2026, Guidance and April 30, 2026, Memorandum: Clarification of Regulatory Provisions Concerning Limits on Flaring Associated Gas for New Oil Wells. Letter to Aaron Szabo, OAR Assistant Administrator from Emily C. Schilling, Holland & Hart. May 6, 2026.

[330] Continental Resources (2026a). Letter to the EPA Administrator. Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Request for EPA's reconsideration of the BSER for associated gas and the requirements governing technical infeasibility determinations under in 40 C.F.R. § 60.5377b. April 23, 2026.

[331] Chrod Energy (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. pt. 60, subpt. OOOOb: Reconsideration of the Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 17, 2026.

[332] Kraken Oil and Gas Partners LLC (2026). Letter Re: Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, 40 C.F.R. Part 60, Subpart OOOOb: Expiration of the Associated Gas Technical Infeasibility Compliance Option, 40 C.F.R. § 60.5377b(f). April 24, 2026.

duration might be needed in order to sustain production.

In addition, EPA recognizes that there may be situations where owners or operators are regularly able to route a portion of the associated gas produced to a gas gathering line or collection system, or to use a portion of the associated gas for another purpose identified in 40 CFR 60.5377b(a)(2), (3), or (4) but are not able to utilize 100 percent of the gas.

The EPA solicits comment on whether it is possible to address all of these scenarios by introducing a flexibility that would allow routine flaring in situations where it is technically infeasible to comply with any of the options in 40 CFR 60.5377b(a). One example of such approach would be to separate wells into two groups. The first group would include: wells in new areas where the construction of a gas gathering line or collection system is not yet underway; wells that are connected to a gas gathering line or collection system but experience frequent interruptions; wells that are connected to a gas gathering line or collection system that reduces capacity or ceases to operate; and wells that route some of their associated gas to a gathering system or use a portion of the associated gas for another purpose identified in 40 CFR 60.5377b(a)(2), (3), or (4), but are not able to find uses for 100 percent of the gas.

For this group of wells, the EPA could provide owners or operator the option to routinely flare (or route to a control device that achieves 95.0 percent reduction in emissions) if they demonstrate that it is technically infeasible to comply with 40 CFR 60.5377b(a). This proposed approach is consistent with the December 2022 Supplemental Proposal.[333]

The second group of wells would include those located in areas where a gas gathering line or collection system is either available or under development, and where the owner or operator has a contractual agreement to route 100 percent of the routed gas

[333] 87 FR 74702 (December 22, 2026).

into a gas gathering line or collection system to a sales line once the system is ready to accept the gas. For these wells, the EPA could allow owners or operators to routinely flare the associated gas (or route to a control device that achieves 95 percent reduction in emissions) until it can be routed to a gas gathering line or collection system to a sales line. The Agency could consider whether to include a limit on the duration an owner or operator may flare during pipeline construction, *e.g.*, 3 years from the time the well begins operation. The Agency is requesting comment on what constitutes an appropriate time frame for limiting routine flaring for new wells under this scenario. (Question III.9h) Owners and operators of wells in this group could be required to submit in their initial annual report the details of the contractual arrangement, as well as the schedule that outlines when compliance will be achieved. In each subsequent annual report, the owner or operator could be required to submit an update on the status of the effort, along with a detailed explanation of any delays in schedule. The EPA is also specifically requesting comment on whether separate requirements for this second group of wells, or whether the considered requirement for annual technical infeasibility determinations and certifications would achieve the same objective of requiring compliance with 40 CFR 60.5377b(a) when the gas gathering line or collection system is able to accept the associated gas produced. (Question III.9i)

K. Well Site Subcategorization

The EPA is proposing to subcategorize different types of well site affected and designated facilities to address petitioner concerns related to the burden of complying with the March 2024 Final Rule for certain types of well sites where the cost of compliance with the March 2024 Final Rule may be more than that subcategory of the industry could bear and survive. The Agency is co-proposing two different options for subcategorizing wells to address this issue: 1) subcategorizing by production volume (*i.e.*, having a subcategory for “marginal” wells); or 2) subcategorizing by well type (*i.e.*,

having a subcategory for "conventional" wells). The EPA is proposing that the Agency could choose to finalize one of these options. Under either of these scenarios, the EPA would determine standards for the subcategory based on a BSER analysis that is specific to the subcategory. As described in the following section, in addition to evaluating the cost effectiveness on a cost per ton of emissions reduction basis as one metric of cost reasonableness, the Agency also evaluated the cost reasonableness of the proposed standards for each subcategory option (*i.e.*, for marginal wells and for conventional wells) by comparing the capital and on-going compliance costs to the overall revenue less operating costs (*i.e.*, profits) at the site level. The EPA also evaluated whether the same proposed standards would be appropriate for conventional wells based on the analysis for marginal wells and the similarities between the two subgroups. Section III.K.1 of this preamble provides information regarding the first option, including the definition of marginal wells, how marginal wells have been addressed in past EPA NSPS rulemakings, petitioner concerns pertaining to compliance with the NSPS OOOOb and EG OOOOc for marginal wells, the EPA's proposed requirements for emissions sources at marginal wells, and the rationale for the proposed emissions requirements. Section III.K.2 of this preamble provides information regarding the second option, including the definition of conventional and unconventional wells, petitioner concerns pertaining to compliance with the NSPS OOOOb and EG OOOOc for conventional wells, the EPA's proposed requirements for emissions sources at conventional wells, and the rationale for the selected emissions requirements.

1. Option 1. Subcategorization of Marginal Wells

There is considerable diversity throughout the many different oil and natural gas wells, and well sites, across the country. One significant aspect of this diversity is related to the level of oil and/or gas production from each well, which can vary over the life of the well. An important subset of the industry are wells that have lower production levels.

Low production wells (*i.e.*, wells with less than 15 barrels of oil equivalent per day) are the most numerous types of existing wells, comprising more than 78 to 80 percent of existing oil and natural gas wells in the United States. These wells accounted for approximately 7 percent of total U.S. oil and natural gas produced in 2024.[334] These "low production wells" are frequently existing wells (existing sources subject to EG OOOOc) that are nearing the end of their productive life but continue to produce at low levels for a decade or more. Within the oil and natural gas industry, there are several commonly used terms to describe wells that produce less oil and/or gas that are used for a variety of reasons. Different industry groups and government entities can use slightly different terms, sometimes to describe the same or similar wells, and sometimes to describe slightly different wells. Further, these terms can sometimes be used in conjunction with different defining criteria such as production-based thresholds and/or defined at the site level (which can consist of multiple individual wells) instead of the individual well level. The inconsistent use of terminology, and the associated defining criteria, can lead to confusion. For example, several state tax codes have different tax requirements for low production wells and often peg the applicability of those different requirements to a specific volume of production of oil and/or gas. Although the definition and requirements can vary, they tend to center around a threshold of a maximum daily average oil production of 15 barrels of oil or a maximum daily average gas production of 90 thousand cubic feet of gas per day (Mcfd) over a set time period.[335] For example, Colorado Title 39. Section 39-29-105(1)(b) exempts gross income from the sale of oil and gas produced from "any wells that produce fifteen barrels per day or less of oil and gas produced from wells that produce ninety thousand cubic feet or less of gas per day for

[334] U.S. Energy Information Administration (2025). The Distribution of U.S. Oil and Natural Gas Wells by Production Rate with Data Through 2024. U.S. Department of Energy (DOE). December 2025.
[335] Colorado Title 39. Section 39-29-105(1)(b); Texas Tax Code § 201.059 (2025) (Credits for Qualifying Low-Producing Wells); Illinois Statutes Chapter 35. Revenue § 450/2-15.

the average of all producing days" for the taxable year. Similarly, the definition from the Energy Policy Act of 2005 (codified at 42 U.S.C. § 15903) for a "marginal property" refers to an onshore unit, communitization agreement, or individual lease that produces, on average over the prior three production months, less than 15 barrels of oil per well per day or 90 million BTU of gas per well per day, considering only wells that produced on more than half of those days. However, many wells produce both oil and natural gas, which makes applying these criteria for low producing wells challenging. Barrel of Oil Equivalent (boe) is a common metric that is used to provide a standardized way to express energy content across different fuel types, allowing a comparison of oil and natural gas wells on an equal footing, as well as accounting for wells that produce both. Because oil is measured in barrels and natural gas in cubic feet, boe serves as a common metric that converts both oil and natural gas into a single, comparable unit. The conversion is straightforward: one thousand cubic feet of natural gas contains approximately one-sixth of the energy of a barrel of oil; therefore, 6,000 cubic feet of natural gas (6 Mcf) has the energy equivalent of one barrel of oil. Accordingly, the criteria used to define a marginal well can alternatively be defined as a well with a maximum daily average oil and/or gas production level of 15 boe per day. By way of another example of how various terms for low production wells have been defined, the federal Internal Revenue Code defines a "stripper well[336] property," with respect to any calendar year, as any property with respect to which the average daily production of domestic crude oil and domestic natural gas from producing wells on such property for such calendar year divided by the number of such wells is 15 barrel equivalents or less.[337] This definition uses the boe metric but introduces the concept of providing a definition for an entire site or property instead of individual well.

---

[336] "Stripper well" is another term used to describe low production wells.
[337] 26 U.S.C. 613A.

Yet another term frequently used is "marginal well." This term is generally used for wells that are marginal in terms of profitability. Although "marginal well" is a commonly used term, defining what classifies a well as economically marginal is challenging, as the profitability depends on a number of factors, including the cost of production and the price of oil and natural gas. However, the EPA notes that most stripper/low production wells are likely to be marginally profitable wells, (*i.e.*, marginal wells), and the term has become synonymous with low production wells.

After examining different terms and defining criteria for characterizing wells that produce less oil and/or gas, the EPA is proposing to define the terms "marginal well" and "marginal well site" based on a production-based threshold, for purposes of establishing a new subcategory within NSPS OOOOb and EG OOOOc. Specifically, the EPA is proposing to define "marginal well" for purposes of NSPS OOOOb and EG OOOOc as a well that produced less than or equal to 15 barrels of oil equivalent per day over the prior 12-month period and define the term "marginal well site" as a well site with only marginal wells and the total cumulative oil and natural gas produced from all the wells at the site is less than or equal to 15 barrels of oil equivalent per day over the prior 12-month period. And the Agency is proposing to create a new subcategory for marginal well sites such that if a well site meets this definition, then the well would be subject to a different group of standards as compared to a non-marginal well that does not meet this definition. CAA section 111(b)(2) authorizes the EPA to distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing standards of performance. Section III.K.1.d further discusses the proposed definition for marginal wells.

a. Marginal Wells in NSPS OOOO Series of Rulemakings

The topic of marginal wells has arisen in previous rulemakings for the oil and gas sector. Industry representatives have repeatedly raised concerns about the economic

impacts of complying with VOC and methane emission requirements for marginal wells, arguing that these requirements would force many wells to shut-in.[338] They have also provided examples of marginal wells emitting less than higher producing wells.[339] Other stakeholders, however, have submitted information showing that marginal wells can emit amounts comparable to, or even greater than, higher producing wells.[340] As new information has emerged over the last 15 years, the EPA's conclusions about how to regulate emissions from these marginal wells have evolved accordingly. Table 4 provides a brief summary of our previous rule rationale and outcomes related to marginal wells. Note that much of the focus in past rulemakings centered on the NSPS for fugitive emissions from leaking equipment components at marginal well sites.

Table 4. Brief Summary of EPA Conclusions and Actions Related to Low Producing/Marginal Wells

Action / Rule	Outcome	Rationale
2011 Proposed[341] and 2012 Final NSPS OOOO[342]	No distinction between marginal wells and non-marginal wells.	Early rules focused on broader NSPS requirements; no special consideration or analysis specific to marginal wells.[343] Well site fugitive emissions not regulated.
2015 Proposed NSPS OOOOa[344]	Proposed exemption from fugitive emissions monitoring and repair requirements for wells with production levels less than 15 boe/day.	The EPA indicated that marginal wells had lower fugitive emissions and were mostly owned by small businesses.
2016 Final NSPS OOOOa[345]	The EPA did not finalize the proposed exemption. Required	The EPA concluded that fugitive emissions levels correlate with

[338] U.S. EPA (2016). EPA's Responses to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. May 2016. (EPA-HQ-OAR-2010-0505-7632); and U.S. EPA (2023a). Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule. November 2023. (EPA-HQ-OAR-2024-0358).
[339] U.S. EPA (2023a). *See*, *e.g.*, pgs. I-2-9 to I-2-10.
[340] EPA-HQ-OAR-2021-0317. *See*, *e.g.*, pgs. 28-29.
[341] 76 FR 52738 (August 23, 2011).
[342] 77 FR 49490 (August 16, 2012).
[343] U.S. EPA (2011). Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Technical Support Document for Proposed Standards. July 2011. EPA-453/R-111/-002; U.S. EPA (2012). Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards. April 2012.
[344] 80 FR 56593 (September 18, 2015).
[345] 81 FR 25824 (June 3, 2016).

	semiannual monitoring and repair for fugitive emissions from all wells, including marginal wells.	equipment counts, not production levels; similar equipment at all sites. The EPA's view changed between proposal and final, such that at final, the EPA did not find that marginal wells had lower fugitive emissions.
2018 Proposed Revisions to 2016 NSPS OOOOa[346]	Proposed less frequent monitoring (biennial) and repair for fugitive emissions at wells with production levels less than 15 boe/day.	New information indicated lower fugitive emissions and fewer components at lower production sites.
2020 Final Revisions to NSPS OOOOa[347]	The EPA did not finalize the proposed biennial fugitive emissions monitoring provisions. Rather, wells with production levels less than 15 boe/day were entirely exempted from fugitive monitoring and repair requirements.	The EPA analysis showed monitoring for fugitive emissions costs outweighed benefits of the reduction of VOC emissions for low production wells. This analysis did not consider the cost effectiveness of methane reductions.
2021 Proposed NSPS OOOOb and EG OOOOc[348]	Proposed to remove the fugitive emissions monitoring and repair requirements exemption in NSPS OOOOa for wells with production levels less than 15 boe/day. Proposed to instead set different fugitive monitoring and repair standards for fugitive emissions at well sites based on the calculated baseline site-wide methane fugitive emissions level.	The EPA explained that production level is not an appropriate threshold for determining monitoring requirements for fugitives; and that monitoring for fugitive emissions should be based on a required calculation of site-wide methane fugitive emissions. These emissions were determined, in part, through equipment /component counts and emission factors.
2022 Supplemental Proposed NSPS OOOOb and EG OOOOc[349]	Withdrew the 2021 NSPS proposal that based fugitive emissions monitoring and repair requirements on calculated baseline site-wide methane fugitive emissions levels. Instead, proposed fugitive emissions monitoring requirements based on the number and type of equipment at the site.	Studies confirmed that fugitive emissions correlate with equipment counts, not production levels.
2024 Final NSPS OOOOb and EG OOOOc[350]	The EPA finalized fugitive emissions monitoring and repair requirements based on equipment at the site. Sites with more	No compelling information was provided that suggested marginal well sites have fugitive emissions that are lower than non-marginal

[346] 83 FR 52056 (October 15, 2018).
[347] 85 FR 57398 (September 15, 2020).
[348] 86 FR 63110 (November 15, 2021).
[349] 87 FR 74702 (December 6, 2022).
[350] 89 FR 16820 (March 8, 2024).

	equipment are subject to more frequent monitoring. The EPA also finalized the repeal of the exemption from fugitive emissions monitoring and repair requirements for marginal wells under NSPS OOOOa.	well sites. In particular, the DOE marginal well study reinforced that fugitive emissions are more correlated to equipment counts/equipment type than production.[351] Further, the TSD for the final rule included a chapter on marginal wells explaining, in part, why the EPA opted to not regulate marginal wells differently.[352]

In the March 2024 Final Rule preamble, the EPA concluded that emissions, particularly fugitive emissions, are not strongly correlated with production levels. In that action, the Agency explained: "the EPA does not have compelling information that suggests production levels should provide the basis for consideration of different fugitive emissions requirements for well sites."[353] Since that time, the EPA has continued to evaluate the available emissions data from marginal wells. A detailed discussion of our current understanding and conclusions on this topic is provided in section III.IV.J.1.e.

As noted above, most of the discussion about marginal wells in the context of the EPA's NSPS and EG has focused on requirements for monitoring and mitigating fugitive emissions. However, other emission sources at marginal wells are subject to NSPS OOOOb or will be subject to state or federal plans in accordance with EG OOOOc. In this action, instead of focusing on fugitive emission sources as in previous rulemakings, the Agency evaluated the full emissions profile of a marginal well site, considering all of those sources at a marginal well site, and evaluated whether emissions from the various sources were directly correlated with production. For some of these emission sources, such as fugitives, process controllers, pumps, compressors, and liquids unloading, there is

[351] Bowers, Richard L (2022). Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. https://doi.org/10.2172/1865859. ("DOE Marginal Well Study")
[352] U.S. EPA. (2023b). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Background Technical Support Document (TSD) for the Final New Source Performance Standards (NSPS) and Emissions Guidelines (EG); Chapter 6 (Financial Analysis of Marginal Wells). November 2023.
[353] 89 FR 16990 (March 8, 2024)

not a strong correlation between production levels and emissions. For fugitives, controllers, and pumps, emissions correlate with the counts and types of equipment, as well as the maintenance practices, more so than with production levels. Likewise, for liquids unloading, emissions are related to the frequency of unloading events and unloading techniques rather than being directly correlated with production. However, for other emission sources, namely associated gas and storage vessels, there is a more defined relationship between production volumes and potential emissions.

For example, some emissions from storage vessels, particularly "working loss" emissions (*i.e.*, the VOC and methane releases from storage tanks that occur during filling or emptying operations where the liquid entering or leaving the tank displaces vapor), are directly dependent on the throughput of liquid through the vessel. Similarly, the potential for associated gas production is directly correlated to the amount of oil produced. Typically, the more oil that an oil well produces, the more associated gas it emits. Thus, for these emission sources, the EPA developed representative emission sources that correlate potential emissions levels to the level of production. The Agency further discusses the development of representative emission sources at marginal well sites, and how that factored into the EPA's proposal to set standards for the new marginal well subcategory, in section IV.J.1.f.

While some newly drilled wells can be marginal wells, the vast majority of marginal wells are existing oil and gas wells (subject to EG OOOOc), whose production has declined over time because of reservoir pressure drops. While there are no provisions specific to marginal wells in the current versions of NSPS OOOOb or EG OOOOc (*i.e.*, there are no standards or presumptive standards where applicability or stringency depends on production level), there are less stringent provisions for smaller well sites, which do not have major production and processing equipment and are expected to have lower emissions. For example, at single wellhead sites, small well sites, and multi

wellhead sites, as defined in NSPS OOOOb and EG OOOOc, the fugitive emission requirements are less stringent than those that apply at larger well sites (*i.e.* well sites with major production and processing equipment or centralized production facilities) because these smaller types of sites often have fewer fugitive emissions components and, by definition, do not have major production and processing equipment. Additionally, according to the March 2024 Final Rule, which represents the existing requirements for storage vessels under NSPS OOOOb, emission controls are not required for storage vessels if emissions are less than 6 tpy VOC or 20 tpy methane.[354] *See* 40 CFR 60.5365b(e). For EG OOOOc, under the existing requirements for storage vessels, only the 20 tpy methane threshold is included because the only pollutant regulated under those emission guidelines is GHG (expressed as a limitation on methane). *See* 40 CFR 60.5361c.[355] The EPA expects that few, if any, storage vessels at marginal well sites would exceed the 20 tpy methane threshold.[356] Under EG OOOOc, the current requirements for existing well sites with associated gas containing less than 40 tpy methane allow owners or operators to flare the gas without a demonstration of technical infeasibility. *See* 40 CFR 60.5391c(b). These provisions result in less stringent requirements for many marginal wells under NSPS OOOOb and EG OOOOc in the March 2024 Final Rule.

b. Petitioner Concerns Related to Marginal Wells for NSPS OOOOb and EG OOOOc Requirements

Despite the March 2024 Final Rule having less stringent requirements for smaller well sites, an industry petitioner and multiple industry groups have expressed significant

[354] 89 FR 16896-16897 (March 8, 2024).
[355] 89 FR 16897-16898 (March 8, 2024).
[356] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

concerns related to how the March 2024 Final Rule affects marginal well sites and requested that the EPA provide relief for these sources.[357] According to the petitioner, oil and natural gas marginal wells are those most affected by the cost of regulation. They estimate that approximately 300,000 marginal wells, representing 0.4 percent of U.S. oil and gas production, will be shut-in as a result of the rule, primarily due to the requirements for process controllers and fugitive emissions monitoring.[358] In Chapter 6 of the TSD for the March 2024 Final Rule, the EPA discussed the complexities associated with estimating the number of wells that might be shut-in as a result of the rule.[359] The EPA noted in the March 2024 Final Rule TSD that there are a number of reasons that marginal wells may continue to operate at low or even negative profits rather than be shut-in and plugged, including accounting practices that allow operators to delay the costs associated with plugging wells far into the future. The TSD also highlighted that the uncertainty surrounding future oil and natural 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 and also makes it extremely difficult to determine the full impact of regulation on the financial status of marginal well owners.

Since the March 2024 Final Rule was promulgated, however, the EPA continued to explore the feasibility of estimating well shut-in and plugging decisions. Review of the academic literature on oil and gas asset valuation,[360] combined with examples from

---

[357] Independent Petroleum Association of America (IPAA) (2024). Re: Provisions in EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review" Creating Immediate Compliance and Implementation Issues; EPA-HQ-OAR-2017-0317.
[358] IPAA (2024); *see* pg. 2.
[359] U.S. EPA (2024) Chapter 6 of the TSD.
[360] See, *e.g.*, Clarke, H.R. and Reed, W.J. (1990). *Oil-well valuation and abandonment with price and extraction rate uncertain*. Resources and Energy, 12(4): 361-382. https://doi.org/10.1016/0165-0572(90)90029-I., and Smith, J.E. and McCardle, K.F. (1996). Valuing Oil Properties: Integrating Option Pricing and Decision Analysis Approaches. Operations Research, 46(2): 198-217. https://www.jstor.org/stable/222860.

industry of well-level financial analysis,[361] provided the EPA with confidence that, while it could not account for every factor relevant to the shut-in decision for operators, it could at least provide a credible estimate of the impacts of the March 2024 Final Rule and this proposed rule. Subsequent work has focused on developing a well shut-in decision methodology and parameterization that could be applied broadly to the universe of marginal well sites in the United States, using location-specific information (such as on severance tax rates and decommissioning costs) when possible. The resulting analysis framework has been applied in the RIA for this proposed rule, with the EPA estimating that between 100,000 and 200,000 marginal wells could cease operation as a result of the March 2024 Final Rule. The petitioner and other industry groups provided various recommendations to the EPA for ways to alleviate the burden on marginal wells, including establishing different standards for fugitive emissions, associated gas, and process controllers.[362]

An industry group, the Michigan Oil and Gas Association (MOGA), provided similar information as the petitioner cited above to the EPA, generally expressing dissatisfaction with the standards as applicable to marginal wells.[363] MOGA asserted that the requirements for fugitive emissions monitoring for marginal wells are unnecessarily and unreasonably expensive (especially OGI) and time-consuming. According to MOGA, marginal wells generate low and limited production revenue, and successful operation is dependent upon the ability to operate at low cost. MOGA further asserted that the March 2024 Final Rule does not take this into consideration and suggests that the EPA create a

---

[361] See, *e.g.*, Riverside Energy comments on the November 2021 Proposal (EPA-HQ-OAR-2021-0317-0411), Michigan Oil and Gas Association comments on the December 2022 Proposal (EPA-HQ-OAR-2021-0317-2257), and Joint Industry Working Group analysis performed to assess proposed revisions to Colorado state oil and natural gas regulations (Exhibit A at https://www.sos.state.co.us/CCR/Upload/AGORequest/RegulatoryAnalysisAttachment2013-01215.PDF.).
[362] IPAA (2024).
[363] Geer, J., President & CEO, Michigan Oil and Gas Association (MOGA). (2025) Letter to Aaron Szabo, Assistant Administrator, Office of Air and Radiation, EPA. May 21, 2025. Proposed Revisions to the Methane Rule (OOOOb & OOOOc).

subcategory for marginal wells with requirements proportional to potential emissions and the cost of monitoring.

In addition to expressing concerns as part of a petition letter discussed earlier in this preamble, the National Stripper Well Association (NSWA) submitted additional information and met with EPA staff and officials on several occasions to further discuss their concerns and specific recommendations related to stripper wells.[364] The NSWA defines "stripper well" as a well that produces less than an annual average of 15 barrels of oil per day (BOPD) or 90,000 cubic feet of gas per day (90 mcfd) or 15 barrels of oil equivalent per day (BOED).[365] According to NSWA, stripper wells operate with low profit margins, with an average stripper well generating approximately $500 in annual net profit. The NSWA stated that the stripper well industry cannot bear any additional regulatory cost and stated that the current regulations will result in a decrease in domestic oil and gas production, tax revenue, and jobs. The NWSA also contended that regulation of stripper wells would be a misallocation of Agency resources.

Using well production levels and oil and natural gas projected prices from the U.S. Energy Information Administration (EIA), the EPA's BSER analysis for this proposed rule (as explained below in section IV.J.1.c) estimates an annual net profit of $11,793 for the average marginal gas well and $43,064 for the average marginal oil well (under a mid-range price scenario), where oil wells are defined as having a gas-to-oil ratio of 6,000 standard cubic feet per barrel or less and marginal wells are defined as producing 15 boe per day or less.[366] Although considerably different than the values

---

[364] Montalban, P. Chairman, National Stripper Well Association and Bradley, S., Board Member, National Stripper Well Association. (2025). Letter to Jodi Howard, EPA, Group Lead, Fuels and Incineration Group, EPA. Subject: 0000b & 0000c Revisions per Multiple Meetings Between NSWA and EPA. July 29, 2025.

[365] *Id.*

[366] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

provided by NSWA, the EPA's analysis still indicates that the March 2024 Final Rule has significant negative impacts on the marginal well portion of the oil and natural gas industry as noted above. In the following sections, the Agency discusses the revised approach for considering cost reasonableness of the proposed revised regulatory requirements for marginal well sites given the lower profits at marginal well sites.

c. BSER for Marginal Wells

CAA section 111(a)(1) defines "standard of performance" as a standard that reflects "the degree of emission limitation achievable through the application of the best system of emission reduction [BSER] which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." Under the final EG OOOOc rule, States must submit plans which include standards of performance that reflect the degree of emission limitation achievable through application of the BSER for existing sources, as identified by the EPA in the EG. *See* 40 CFR 60.5363c(a)(4).

CAA section 111(a) does not provide specific direction to the EPA regarding what metric to use when "taking into account" costs for the BSER analysis, affording the EPA considerable discretion in choosing a reasonable means of cost consideration.[367] As described in the proposal for the 2016 Rule,[368] the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) has explained that when setting standards under CAA section 111, the consideration of costs has included an evaluation of whether the

[367] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("Because section 111 does not set forth the weight that be should assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them."); *New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992) (similar); *see also, e.g.*, *Husqvarna AB v. EPA*, 254 F.3d 195, 200 (D.C. Cir. 2001) (finding EPA's approach to considering costs reasonable "[b]ecause [CAA] section 213 does not mandate a specific method of cost analysis").

[368] 80 FR 56593, 56616 (September 18, 2015).

cost of the standard would be "exorbitant,"[369] "greater than the industry could bear and survive,"[370] "excessive,"[371] or "unreasonable."[372] These various formulations seek to describe the outer limits of cost considerations for BSER under CAA section 111 and for convenience in this rulemaking, as in previous rulemakings, the EPA will use reasonableness as the guide, so that a control technology may be considered the "best system of emission reduction . . . adequately demonstrated" if its costs are reasonable, but cannot be considered the BSER if its costs are unreasonable.[373]

While the EPA has proposed and finalized treating marginal wells differently in the past,[374, 375] in this action, the EPA is proposing to take a new approach, in the context of these oil and gas regulations, to assess whether compliance costs are reasonable for marginal well sites. In addition to evaluating the cost effectiveness on a cost per ton of emissions reduction basis for different control options at the source level, the Agency also evaluated the cost reasonableness of different control options based on the capital and on-going compliance costs compared to the overall revenue less operating costs (*i.e.*, profits) at the site level applicable to this subcategory of the industry. Although the EPA has not previously taken this exact type of "dual" evaluation approach for this sector, the Agency has evaluated the cost reasonableness of regulatory requirements using multiple metrics for this sector in other ways and in other sectors. For example, in the March 2024 Final Rule, in addition to evaluating the cost effectiveness of various control options, the Agency also evaluated the industry-wide compliance costs compared to revenue.[376] As

---

[369] *Lignite Energy Council*, 198 F.3d at 933 ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant").
[370] *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975).
[371] *Sierra Club v. Costle*, 657 F.2d 298, 383 (D.C. Cir. 1981) (noting the EPA's conclusion that the industry's "forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable").
[372] *Id*.
[373] EPA has taken a similar approach in prior rulemakings under CAA section 111. *See, e.g.*, 89 FR 16820, 16847 (March 8, 2024); 91 FR 1910, 1913 (January 15, 2026).
[374] 80 FR 56612 (September 18, 2015)
[375] 85 FR 57400 (September 15, 2020)
[376] 89 FR 16847 (May 8, 2024).

another example, in the January 2026 final rule entitled "New Source Performance Standards Review for Stationary Combustion Turbines and Stationary Gas Turbines," the EPA evaluated costs using several different metrics, which had also been used in previous NSPS rulemakings, including total cost, cost as a percentage of capital cost, incremental cost-per-ton of pollutant reduced, and cost per unit of production.[377] These examples illustrate that the Agency has a history of considering multiple cost metrics when the situation suggests that such a multi-faceted assessment of costs would be appropriate. Assessing whether compliance costs might be excessive or exorbitant is not always an easy or straight-forward task. There can sometimes be complicated factors to consider, which necessarily requires that the EPA examine the issue of costs from multiple angles and with multiple lenses. As explained more below, such a multi-metric approach is appropriate here.

The basic approach for the evaluation in this proposal is summarized as follows: first, the EPA created representative well sites to characterize the production levels, equipment, and baseline emissions at typical marginal well sites; next, the Agency identified potential control options for each emission source at the representative marginal well site, and estimated the capital and annual costs, as well as the cost effectiveness values for each potential control at each emissions source; third, the EPA compared the anticipated costs of compliance for each potential control option to the estimated well site profits to assess cost reasonableness of the individual control option; fourth, the EPA developed regulatory alternatives that included different combinations of potential control options, considering cost effectiveness and cost reasonableness of the individual control options; finally, the EPA compared the total compliance costs of the emissions control options for all of the emissions sources for each regulatory alternative considered at the representative sites to the total facility emissions reductions and the

[377] 91 FR 1935 (January 15, 2026).

estimated facility profits at the representative site to assess the cost reasonableness of the combination of potential control requirements in each regulatory option considered. The following paragraphs describe how this proposed approach differs from historical approaches for oil and gas rules under CAA 111 and the EPA's rationale for taking a new approach specifically for this subcategory of the oil and gas source category. Details of our evaluation are also provided in the subsequent sections of this preamble. More detailed descriptions and data are located in the Marginal Well TSD,[378] available in the docket for this proposed rule.

In previous NSPS and EG rulemakings for the oil and natural gas industry, the EPA has evaluated reasonableness of control costs by examining different metrics. First, for individual emission sources (*e.g.*, fugitive emissions from leaking components, storage vessels, compressors), the Agency has previously weighed the estimated emission reduction that would be achieved by the control option against the costs of control and determined if the cost of control in relation to the emission reduction is reasonable. The common measure used for this evaluation is "cost effectiveness," which is expressed as a cost per ton of emission reduction achieved.

While cost effectiveness on an individual emission source basis has historically been the primary factor in determining BSER for this industry, the EPA also has evaluated costs at a sector level by assessing the projected new capital expenditures required under each rule (compared to overall new capital expenditures by the sector) and the projected compliance costs (compared to overall annual revenue for the sector) if the rule were to require such controls.[379] When the EPA has conducted such nationwide

---

[378] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.
[379] 89 FR 16863-68 (March 8, 2024).

analyses, the Agency has considered whether the standards in the rule represent costs that are excessive, unreasonable, or greater than the industry could bear.

Previously, the EPA had not directly considered whether the costs of the standards are excessive or greater than each segment of the industry could bear. The Agency's prior analyses were based on the whole onshore oil and natural gas production sector, even though there is a wide difference in the amount of production and associated revenue between different types of wells. Newly drilled sites may produce over 1,000 boe per day, while many older wells have production levels of less than 15 boe per day. While the revenue generated from selling oil and natural gas differs greatly between these lower and higher production sites, the costs of emissions controls are often largely the same. For instance, the cost to install the infrastructure to route associated gas to a sales line is substantially the same regardless of the amount of oil and associated gas that is produced from a site. Due to these circumstances, the emissions control costs for sites producing less oil and natural gas represent a much larger share of the revenue generated for a marginal well site than for a site with high production volumes. Put another way, the oil and natural gas industry, as a whole, includes a very wide range of operations such that certain costs may be reasonable for some regulated entities and simultaneously unreasonable for others. The EPA's historic approach to considering industry-wide costs did not account for these real-world differences that are unique to this industry considering the very large number of sources in the industry. In reality, this particular industry has sub-industries, or select portions of the larger industry, that operate very differently from the larger industry. To account for the divergent revenues of these different oil and gas site types, in this proposal, the EPA is both evaluating cost effectiveness on a cost per ton of emissions reduction basis for each control option at the source level and cost reasonableness based on the capital and ongoing compliance costs compared to overall revenue less operating costs (*i.e.*, profits) for this subcategory of the

industry (*i.e.*, marginal wells). In this action, the Agency is proposing that for a control option to be considered BSER, the associated costs would have to be reasonable under both cost metrics.

Additionally, the EPA has historically assessed the cost effectiveness of potential standards for oil and natural gas sources (for all past NSPS and EG for oil and gas) on a particular type of equipment or process in isolation, *i.e.*, without consideration of the compliance costs of co-located equipment integral to production. This approach for this industry resulted in cases wherein some control options appeared cost reasonable in isolation. However, owner/operators that are subject to the NSPS and EG do not just own and operate one isolated piece of equipment or process. An owner/operator in this industry likely has to bear the compliance costs of multiple standards simultaneously. For example, at an individual oil well site an owner/operator might be subject to five different standards: (1) fugitives monitoring, (2) associated gas, (3) pneumatic pumps, (4) process controllers, and (5) storage vessels. As such, under this scenario, the particular owner/operator would have to pay to implement all five standards. The EPA has previously determined for this industry that each standard was cost reasonable in isolation with little regard to the total, cumulative, compliance costs that the NSPS or EG imposed on the owner/operator.[380] As explained more below, the approach that the EPA is proposing here seeks to correct this oversight for marginal wells, where this issue matters most because profit margins can be very small, by considering the total cumulative costs that the oil and gas regulations are imposing on those owners and operators. The EPA proposes that this is a better way to assess costs in the BSER analysis for the marginal well subcategory of the industry.

Because the marginal well subsector of the onshore oil and natural gas production sector operates under distinct economic conditions, such that the traditional cost

[380] *See, e.g.*, 89 FR 16827, 16867 (March 8, 2024).

effectiveness approach may not fully represent the potential impact on this subsector, the EPA is proposing that it is appropriate to consider the cost reasonableness of the potential standards at the site-level, instead of piecemeal. As previously noted in section III.K.1.b, the EPA estimates that between 100,000 and 200,000 marginal wells could cease operations due to the costs of complying with the NSPS OOOOb or EG OOOOc. In light of these concerns, the Agency is including consideration of the total compliance costs in relation to profitability on a site basis in the BSER analysis for marginal well sites. The EPA proposes that this approach to cost reasonableness for purposes of the BSER analysis is more appropriate for this NSPS and EG for marginal wells because it allows the Agency to fully account for all compliance costs imposed on the owner/operator of these particular emissions sources and to compare those costs to the distinct economics of marginal well sites. Further, by incorporating profitability into the cost consideration for marginal wells, the EPA can more accurately assess the reasonableness of the total cost of compliance for this segment of sources relative to the guidelines that courts have outlined in CAA section 111 caselaw. Put another way, incorporating profitability into the cost prong of the BSER analysis here allows the Agency to more accurately characterize whether a particular cost is exorbitant, excessive, or greater than this subcategory of the industry (marginal wells), could bear and survive. By way of a simplified example, a total NSPS compliance costs of $100 per year would objectively not be more than an industry could survive if the average source in that industry generated $10,000,000 in profit each year. However, if the average source generated only $90 in profit each year, then, depending on the circumstances and any relevant related facts, the EPA might conclude that same $100 in compliance costs was more than the industry could bear and survive.

A key aspect of this marginal well BSER analysis is the consideration of the profitability of a representative well site to assess cost reasonableness. To assess cost

reasonableness, the EPA calculated the expected revenue for different levels of production and estimated the associated operating costs and profit levels. Specifically, the Agency estimated low-, high-, and mid-range profit levels for different production levels of marginal wells for both oil wells and gas wells. The different profit levels were based on different pricing scenarios for oil and natural gas. The EPA recognizes there are numerous uncertainties associated with these pricing scenario estimates and is requesting comment on this aspect of the analysis. (*See* section III.IV.J.1.l.).

For the BSER analysis, the EPA created representative well sites to characterize the production levels, equipment, and baseline emissions at marginal well sites. Next, the EPA identified potential control options for each emission source at the representative marginal well site, and estimated the capital and annual costs, as well as the cost effectiveness values for each control option at each emissions source. Third, the EPA then compared the annual costs of individual control options to the profit levels of marginal wells. In instances where the annual costs for just one control for one source type were relatively high relative to the expected profits, the EPA removed the control option from further consideration as the BSER because the Agency is proposing to determine that the costs are unreasonable under this metric. For example, for oil well sites with average production levels less than 15 boe/day, the estimated cost of routing associated gas to a sales line represented over 200 percent of the estimated profits for the mid-range pricing option, and over 150 percent of the estimated profits for the highest pricing option (see table 8 in this preamble for a comparison of costs in the March 2024 Final Rule and see the Marginal Well TSD for further details on the analysis of costs). The EPA therefore ruled out this control option for associated gas from the BSER analysis because the costs for this control option are unreasonable (the costs are more than the sub-industry of marginal wells can bear) even before considering the costs of controls for other sources at the site.

Owners and operators recognize revenue and profits at the site level, and make the decision whether to shut-in, or continue to operate, the well(s) at a site. Accordingly, the EPA next combined the control options for all emission sources at a well site previously covered by the NSPS and EG into site-wide regulatory alternatives. The Agency calculated the total site-wide capital and annual compliance costs of the control options considered, as well as the total site-wide emissions reductions and cost effectiveness. The EPA then compared the total annual compliance costs for the regulatory options considered for both a representative marginal well site and a representative marginal well site with major production and processing equipment (a "large well-site") to the profit levels for marginal wells. The Agency proposes to determine the BSER based on the combination of emissions reductions and cost effectiveness, at both the individual control level and the site-level, and how total site-wide annual compliance costs compare to estimated annual profits for the representative site.

The EPA recognizes that there is substantial variation in the equipment and operations at oil and natural gas well sites, even for sites with similar production levels. This representative site evaluation considers these differences by using weighted averages of the number and types of emission sources present and other factors.[381] By using weighted averages, the EPA can evaluate the impact of different options on nationwide emissions reductions, not just the impact for a particular scenario. The EPA based these weighted averages on data, where available, or on the EPA's estimates based on knowledge of the industry.[382]

---

[381] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

[382] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

Additionally, the EPA requests comment on the appropriate consideration of "energy requirements" and whether the energy impacts from curtailed production of oil and natural gas in the United States allows treating marginal and conventional wells differently. (Question III.10a)

d. Proposed Subcategory for Marginal Wells

CAA section 111(b)(2) authorizes the EPA to distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing standards of performance. In this action, to distinguish sources within the crude oil and natural gas source category that have lower oil and gas production rates, the Agency proposes to create a new subcategory within the crude oil and natural gas category for marginal well sites under NSPS OOOOb. The EPA also proposes to create a corresponding subcategory for existing marginal wells sites under the EG of OOOOc. In order to evaluate and establish separate standards for this subcategory of marginal well sites, the EPA must establish definitions for "marginal wells" and "marginal well sites." The Internal Revenue Code, in 26 U.S.C. 613A(c)(6)(E), defines a "stripper well property," with respect to any calendar year, as any property with respect to which the average daily production of domestic crude oil and domestic natural gas from producing wells on such property for such calendar year divided by the number of producing wells is less than 15 boe. The production level used in this stripper well definition of 15 boe/day is a long-recognized criterion in the oil and natural gas industry. Using a production-based definition, like that in the "stripper well" definition above, provides a clear, measurable, and quantifiable metric. Thus, it is well understood in the industry."[383] Therefore, the EPA is proposing to base the definition of "marginal well" on these established concepts. However, the Agency proposes a slightly different approach to the definition of a

[383] Letter from the Producers Association to Ms. Jodi Howard, EPA. September 24, 2025. Re: Provisions in EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review."

marginal well site than the definition of stripper well property used in the Internal Revenue Code. In this action, the EPA is proposing to define a marginal well site as a well site that has a production below the threshold of 15 boe/day total for all wells at the well site. The Agency considers that establishing a definition at the site level is necessary to establish emission controls for equipment located at a marginal well site, such as process controllers and pumps, which service more than one well at the site. A site level definition is also consistent with the EPA's approach to evaluating BSER for this oil and natural gas production source subcategory, where the Agency is considering site-level compliance costs and profits. In addition, the EPA also used the same threshold in a previous action on NSPS OOOOa. Accordingly, the Agency is proposing definitions for both a "marginal well" and a "marginal well site", 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, and marginal well sites are well sites with only marginal wells and where the total oil and natural gas produced from all the wells at the site is less than or equal to 15 boe per day over the prior 12-month period.

The EPA proposes a marginal well site subcategory that is defined as well sites producing 15 boe/day or less of oil and/or gas, but the Agency recognizes that there may be meaningful differences between marginal well sites producing at or near 15 boe/day and those producing substantially less. Certainly, profits decrease as production decreases, as well as the emissions for the sources that are more closely correlated with production levels (*e.g.*, associated gas, storage vessels). In addition, smaller, lower production wells often have fewer process units and less equipment, which results in less emissions from sources such as fugitive components and controllers when compared to larger production sites that have more controllers and more equipment to monitor for fugitives. While the EPA is proposing a single marginal well subcategory that is based on production level, the Agency is also requesting comment on an alternative approach that

would create two separate subcategories: one for marginal well sites with oil and/or gas production levels between 6 and 15 boe/day, and another for marginal well sites with oil and/or gas production levels of less than 6 boe/day. This is discussed in detail in section III.J.1.l of this preamble.

e. Profile of Marginal Wells in the United States

i. Population and Economic Profile

Marginal wells account for a large share of the nation's well count but only a small share of total production. According to the Energy Information Administration, out of a total of 918,000 active U.S. wells in 2024, approximately 717,000 were marginal wells.[384] This means that marginal wells account for approximately 78 to percent of all wells nationwide. These wells accounted for approximately 7 percent of total U.S. oil and natural gas produced in 2024.[385] Based on our analysis of Enverus data, the EPA estimates that oil and gas wells in 2023 were owned and operated by more than 11,000 unique operators.[386] Most marginal wells are owned by firms that also operate many other wells. For example, 51.3 percent of all marginal wells in the U.S are owned by only 127 firms that operate 1,000 or more wells each. 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 own 3.2 percent of all marginal wells in the U.S. and account for 1.9 percent of all marginal well production.

ii. Emissions from Marginal Wells

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

---

[384] U.S. Energy Information Administration (2025). The Distribution of U.S. Oil and Natural Gas Wells by Production Rate with Data Through 2024. U.S. Department of Energy. December 2025.
[385] *Id.*
[386] Enverus accessed on October 25, 2026.

emissions from oil and natural gas production is much greater.[387, 388, 389] On a national scale, the DOE marginal well study estimated that marginal wells account for 1,000,000 ± 140,000 tpy, or roughly 50 percent of total methane emissions from oil and gas production.[390] This is consistent with the EPA's estimates of the proportion of total methane emissions from all onshore oil and natural gas production attributed to marginal wells (approximately 60 percent) on a national basis over the same time period.[391] On a per well basis, this equates to 1.3 ± 0.2 tpy of methane per well, according to the U.S. DOE marginal well study. Similarly, the EPA estimated that approximately 50 percent of VOC emissions from onshore production is from marginal wells.[392] The EPA notes that the U.S. DOE marginal well study did not include emissions from some sources, particularly intermittent sources like liquids unloading; thus, the emissions reported in that study are lower than what the Agency estimates for a representative model well.

Other studies make similar conclusions regarding the population, production, and emissions from marginal wells, such as the Omara, *et al.* study, which indicates that 80 percent of U.S. oil and natural gas production sites were marginal well sites in 2019.[393] On a production basis, the Omara, *et al.* study reports that marginal well sites account for less than 6 percent of the nation's oil and natural gas output in

---

[387]Deighton, J. A., Townsend-Small, A., Sturmer, S. J., Hoschouer, J., & Heldman, L. (2020). Measurements show that marginal wells are a disproportionate source of methane relative to production. *Journal of the Air & Waste Management Association*, *70*(10), 1030–1042. https://doi.org/10.1080/10962247.2020.1808115

[388] Bowers, Richard L. (2022) Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. https://doi.org/10.2172/1865859.

[389] Omara, M., Zavala-Araiza, D., Lyon, D.R. *et al.* Methane emissions from US low production oil and natural gas well sites. *Nat Commun* **13**, 2085 (2022). https://doi.org/10.1038/s41467-022-29709-3

[390] Bowers, Richard L (2022). Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. https://doi.org/10.2172/1865859.

[391] U.S. EPA. (2023). Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. December 2023. EPA-452/R-23-013.

[392] Id.

[393] Omara, et. al (2022). Methane emissions from US low production oil and natural gas well sites. https://doi.org/10.1038/s41467-022-29709-3.

2019. Consistent with the U.S. DOE marginal well study, Omara *et al*. also estimates that marginal wells represent about 50 percent of all methane emissions from oil and natural gas well sites.

According to the U.S. DOE marginal well study, out of the estimated 783,000 marginal wells nationwide, 420,000 are natural gas producing marginal wells and 363,000 are oil producing marginal wells.[394] On a production basis, marginal natural gas wells produce an estimated 460,000,000 boe/yr and marginal oil wells produce an estimated 320,000,000 boe/yr. From an emissions perspective, Omara *et al.* estimate that natural gas producing marginal wells account for the majority of methane emissions from marginal wells at 640,000 ±80,000 ton/yr (or 64 percent of total marginal well methane emissions) and oil producing marginal wells emit 360,000 ±50,000 ton/yr (or 36 percent of total marginal well methane emissions).[395]

Methane and VOC emissions from oil and natural gas producing marginal wells originate from equipment that is part of oil and natural gas production operations such as wellheads, storage vessels, process controllers, pumps, separators, dehydrators, compressors, and flares. Some equipment such as wellheads, storage vessels and separators are the more common types of equipment found at a well site. The U.S. DOE marginal well study indicated that these same types of equipment - wellheads, separators, and tanks- represent the largest and most frequently observed sources of emissions in all regions.[396] The U.S. DOE marginal well study concluded that emissions from marginal wells were not strongly correlated with production and were instead most strongly correlated with major equipment count. That study also observed a highly skewed distribution of methane emissions, with the top 10 percent of emitting sources

---

[394] Bowers, Richard L. (2022). Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. https://doi.org/10.2172/1865859.
[395] *Id.*
[396] *Id.*

contributing 90 percent of the total methane emissions observed. Most of the top emitting sources in the study were due to emissions from malfunctioning or poorly maintained equipment. This is consistent with other studies, including studies of VOC emissions from marginal wells, which showed similar skewed distributions and weak or no correlation with production.[397]

f. Marginal Well Representative Emission Sources

As noted in section III.J.1.c, the EPA began the marginal well BSER analysis by creating representative emission sources to characterize the production levels, equipment, baseline emissions, and the impacts of the March 2024 Final Rule at marginal well sites. The Agency built these representative emission sources from the individual affected/designated facilities (*i.e.*, sources of emissions) covered by NSPS OOOOb or EG OOOOc that may be present at marginal well sites. Specifically, the emission sources that may be present at marginal well sites are:

- fugitive emissions components,
- process controllers,
- pumps,
- associated gas (at oil well sites only),
- storage vessels,
- sweetening units, and
- liquids unloading (at gas wells only).

Note that the EPA excludes compressors (centrifugal and reciprocating) located at all well sites because they are not subject to the March 2024 Final Rule requirements, and thus the Agency did not include them in the marginal well site representative facilities. The Agency does not include well completions in the marginal well site representative facilities, as operators conduct well completions prior to a determination of whether a well is a marginal well (or is continuing to be a marginal well). Thus, the EPA is

[397] Deighton, J. A., Townsend-Small, A., Sturmer, S. J., Hoschouer, J., & Heldman, L. (2020). Measurements show that marginal wells are a disproportionate source of methane relative to production. Journal of the Air & Waste Management Association, 70(10), 1030–1042. https://doi.org/10.1080/10962247.2020.1808115

proposing that all well completions will continue to follow the provisions in 40 CFR 60.5375b prior to determining whether the well meets the definition of a marginal well.

There are four types of well sites addressed in NSPS OOOOb and EG OOOOc for purposes of the fugitive monitoring and repair requirements. These are summarized in table 5.

Table 5. Summary of NSPS OOOOb and EG OOOOc Well Site Types

Well Type	Definition[398]
Single wellhead only well site	A wellhead only well site that contains only one wellhead and no major production and processing equipment.[a]
Small wellsite	A well site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. Small well sites cannot include any controlled storage vessels (or controlled tank batteries), control devices, natural gas-driven process controllers, or natural gas-driven pumps.
Multi-wellhead only well site	A well site that contains two or more wellheads and no major production and processing equipment.[a]
Large well site[b]	A well site that includes one or more controlled storage vessels or tank batteries, one or more control devices, one or more natural gas-driven process controllers or pumps, or two or more of the following: reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and uncontrolled storage vessels or tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water.

[a] Major production and processing equipment means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, control devices, natural gas-driven process controllers, natural gas-driven pumps, and storage vessels or tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.
[b] Large well site is not a defined term in NSPS OOOOb or EG OOOOc. For the purpose of this preamble, the EPA is utilizing the term "large well site" to characterize the type of site described in the fugitive emission standards in NSPS OOOOb and the presumptive standards in EG OOOOc (summarized above in table).[399]

The EPA created representative marginal well model plants for each of the well site types described in table 5. These model plants contain representative equipment and processes (emission sources), as applicable. The following sections describe the emission

[398] *See* 40 CFR 60.5430b, 60.5430c.
[399] *See* 40 CFR 60.5397b(g)(1)(iv), 60.5397c(g)(1)(iv)

sources that may be present at well sites and that are thus included in our model plants, along with an estimate of the baseline uncontrolled emissions for a representative source.

i. Fugitive Emissions Components

Fugitive emissions can, in general terms, be understood as unintended emissions that can occur from a range of components at any time due to leaks or equipment malfunctions.[400] Collectively, these emissions constitute one of the largest sources of methane and VOC at marginal well sites, although the magnitude of these emissions can also vary widely across different facilities and over time. In NSPS OOOOb, a fugitive emissions component is defined as "any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, such as valves (including separator dump valves), connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping."[401] The definition in EG OOOOc is the same, with the exception of only pertaining to emissions of methane and referencing 40 CFR 60.5411c and 60.5396c instead of 40 CFR 60.5411b and 60.5395b, respectively. Table 6 provides the number of components at each representative marginal well site and corresponding emissions estimates for the site. As noted in footnote b to table 5, the fourth well site type, well sites that contain major production and processing equipment will henceforth also be referred to as "large well sites." Details of these well sites, the number of components, and the baseline emission levels are provided in the Marginal Well TSD, available in the docket for this proposed rule.

Table 6. Fugitive Emissions Marginal Well Representative Facilities

[400] NSPS OOOOb and EG OOOOc also contain specific definitions of the term "fugitive emissions" for purposes of certain regulatory provisions. *See* 40 CFR 60.5430b (fugitive emissions definition) and 40 CFR 60.5430c (same).
[401] 40 CFR 60.5430b (fugitive emissions component definition)

Marginal Well Site Type	Number of Components	Baseline Methane Fugitive Emissions (tpy)	Baseline VOC Fugitive Emissions (tpy)
Single Wellhead Only Well Site	112	1.37	0.38
Small Well Site	157	1.87	0.52
Multi-Wellhead Only Well Site	220	2.44	0.68
Large Well Site	385	4.84	1.35

ii. Process Controllers

Process controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure difference, or temperature. In the oil and natural gas industry, many process controllers are powered by pressurized natural gas and emit methane and VOC-containing natural gas to the atmosphere. Process controllers may also be powered by electricity or compressed air, and these types of controllers do not use or emit natural gas.

Natural gas-driven process controllers can be categorized based on the emissions pattern of the controller. Some controllers are designed to have the supply-gas provide the required pressure to power the end-device, and the excess amount of gas is emitted. The emissions of this excess gas are referred to as "bleed," and this bleed occurs continuously. Controllers that operate in this manner are referred to as "continuous bleed" process controllers. These controllers can be further categorized based on the amount of bleed they are designed to have. Those that have a bleed rate of less than or equal to 6 scfh are referred to as "low bleed," and those with a bleed rate of greater than 6 scfh are referred to as "high bleed." Another type of controller is designed to release gas only when the process parameter needs to be adjusted by opening or closing the valve, and there is no venting or bleeding of gas to the atmosphere when the valve is stationary. These types of controllers are referred to as "intermittent vent" process controllers. A third type of process controller, a self-contained process controller, is a controller that

routes the exhaust gas into the downstream piping instead of the atmosphere. Emissions from natural gas-driven process controllers are primarily dependent on the number of controllers at a site, the designed bleed rate (for continuous bleed controllers), and the condition of the controller and frequency of malfunction. Emissions from controllers are not directly tied to production levels.

The EPA does not expect that there are natural gas-driven controllers at every marginal well site. For sites that do have such controllers, the Agency assumed there would be two intermittent vent controllers based on available data regarding the number and predominant type of process controllers at well sites.[402] The EPA estimated the annual emissions to be 2.66 tpy of methane and 0.74 tpy of VOC per marginal well site. Details of the model plant development and baseline emission level are provided in the Marginal Well TSD, available in the docket for this proposed rule.

iii. Pumps

In the oil and natural gas industry, operators frequently use pumps to inject precise amounts of chemicals into a process stream or to circulate glycol. These pumps may use natural gas, compressed air, or electricity as a power source. Of these pumps, those that are pneumatic units driven by natural gas emit methane and VOC to the atmosphere as part of normal operation. In many situations across all segments of the oil and gas industry, operators often rely on natural gas-driven pneumatic pumps where electricity is not readily available. Emissions from natural gas-driven pumps are primarily dependent on the number of pumps at a site and not directly tied to production levels. Based on available data regarding the number of pumps at well sites, the EPA does not expect that there are natural gas-driven pumps at every marginal well site.[403] For those

---

[402] *See* Docket ID. No. EPA-HQ-OAR-2025-1348 (Industry data collected by the EPA through an information collection request (ICR) distributed in 2024 for the NESHAP ("2024 Company Phase Two ICR Facility Responses and Supplemental Information").

[403] Industry data collected by the EPA through an information collection request (ICR) distributed in 2024 ("2024 ICR").

sites that do, the Agency assumed there would only be one such pump, based on the available data.[404] The EPA estimated the annual emissions to be 3.46 tpy of methane and 0.96 tpy of VOC. The Marginal Well TSD, available in the docket for this proposed rule, provides details of the model plant development and baseline emission levels.

iv. Oil Well Associated Gas

Associated gas is natural gas that originates at wells operated primarily for oil production that is released from the liquid hydrocarbon during the initial stage of separation after the wellhead. Associated gas is one of the emission sources where emissions are primarily dependent on production levels. More specifically, the volume of associated gas is related to the amount of gas extracted along with the oil or condensate. Put another way, generally speaking and subject to some caveats, the more oil that a well produces, the higher the potential for associated gas emissions there will be from that well because the crude oil is mixed with some natural gas that contains VOCs and methane. If a well site is producing a small amount of oil, usually the uncontrolled VOC and methane emissions from the natural gas associated with that oil will likewise be small. If, however, the well site is producing a very large amount of oil, then usually there will also be higher amounts of associated natural gas, and the uncontrolled emissions from that gas would usually be higher. Operators typically route the mixture of oil and natural gas to a separator, which sends the liquid to a storage vessel. If the gas exiting the separator is of sufficient quality and quantity, operators generally route it to a gas line, provided there is a sales line nearby that has the capacity to accept the gas and that the gas meets quality specifications. In the absence of a sales line, operators may use the gas for another purpose, such as for onsite fuel (provided the quality is adequate) or recover the gas and reinject it into the same well or another well. If none of these options are feasible, operators typically flare or vent the associated gas.

---

[404] *Id.*

The EPA estimates that the annual associated gas methane emissions from the average marginal well are 10.9 tpy of methane and 3.0 tpy VOC. As previously noted, the amount of associated gas is directly correlated to production levels. The Agency estimates the methane emissions from associated gas could range from around 2 tpy from a well site with 1 boe per day to over 100 tpy from a well site with 15 boe per day and that VOC emissions could range from 0.6 tpy from a well site with 1 boe per day to around 29 tpy for a well site with 15 boe per day. The Marginal Well TSD provides detailed explanations of these estimates.[405]

v. Storage Vessels

Storage vessels at oil and natural gas well sites contain crude oil, condensate, intermediate hydrocarbon liquids, or produced water. They are almost exclusively fixed roof tanks. Typically, the most significant cause of emissions from storage vessels at oil and natural gas sites is the "flashing" that occurs when the pressure of a hydrocarbon liquid (oil, condensate, or water) drops, causing volatile components in the liquid to vaporize and be emitted. Flash emissions are somewhat dependent on throughput, as well as a number of other factors (*e.g.*, volatility, composition, density, temperature, pressure drop). Working loss emissions are directly dependent on the throughput of liquid through the vessel.

In order to estimate methane emissions from storage vessels at marginal wells, the EPA developed emissions factors based on the barrels of oil or condensate per day of the well. The EPA created separate methane and VOC emissions factors for storage vessels containing condensate and those containing heavy oil, then averaged the two factors to estimate the storage vessel emissions. The representative marginal well site storage vessel

[405] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

emissions are 0.63 tpy methane and 2.9 tpy VOC. The origin of the emissions factors and estimated emission levels are provided in the Marginal Well TSD, available in the docket for this proposed rule.[406]

vi. Gas Well Liquids Unloading

In new gas wells, there is generally sufficient reservoir pressure/gas velocity to facilitate the flow of water and hydrocarbon liquids from the wellbore through the well head and to the surface along with produced gas. In mature gas wells, the accumulation of liquids in the wellbore can occur when the bottom well pressure/gas velocity approaches the average reservoir pressure, and there is not enough pressure to force the liquids to the surface. This accumulation of liquids can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production, the operator must remove the fluids to maintain production. Mature gas wells therefore often need to remove or "unload" the accumulated liquids (*i.e.*, liquids unloading) so that gas production is not inhibited.

The choice of what liquids unloading technique to employ is based on a well-by-well and reservoir-by-reservoir analysis. To address the complex science and engineering considerations to cover well unloading requirements, many technologies, techniques, and practices have been developed to address an individual well's characteristics. At the onset of liquids loading, operators typically use techniques that rely on the reservoir pressure. Eventually a well's reservoir pressure is not sufficient to remove the liquids from the well and it is necessary to add energy to the well to continue production. Owners and operators can choose from several techniques to remove the liquids, including manual unloading, velocity tubing or velocity strings, beam or rod pumps, electric submergence

[406] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

pumps, intermittent unloading, gas lift (*e.g.*, use of a plunger lift), foam agents, and wellhead compression. Each of these methods/procedures removes accumulated liquids and thereby maintains or restores gas production. Although the unloading method employed by an owner or operator can itself be a method that mitigates/eliminates venting of emissions from a liquids unloading event, choosing a particular method to meet a particular well's unloading needs is a production engineering decision.

The EPA estimates that the representative emissions from uncontrolled liquids unloading are 2.5 tpy methane and 0.7 tpy VOC per marginal gas well. The Marginal Well TSD, available in the docket for this proposed rule, provides additional detail on the baseline emission level.[407]

vii. Sweetening Units

At oil and natural gas production and processing sites, sweetening units (also called gas sweetening systems or amine plants) are specialized processing units designed to remove acid gases—primarily hydrogen sulfide (H_2S) and carbon dioxide (CO_2)—from sour natural gas or process streams. Sweetening units have been subject to NSPS standards since 1984, as NSPS subpart LLL regulates SO_2 emissions for all sweetening units constructed, reconstructed, or modified after January 20, 1984. In addition, NSPS OOOO, NSPS OOOOa, and NSPS OOOOb all include SO_2 standards for sweetening units. The EPA does not believe that sweetening units are located at well sites, as evidenced by the fact that NSPS OOOO and NSPS OOOOa (initially for NSPS OOOOa) only applied to sweetening units located at onshore natural gas processing plants. However, in 2020, the Agency modified NSPS OOOOa to align with NSPS LLL, by revising the affected facility description for the SO_2 standards to include all onshore

[407] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

sweetening units that process natural gas produced from either onshore or offshore wells.[408] While the EPA made this change, the Agency is not aware that sweetening units are located at well sites, much less at marginal well sites. However, the EPA is proposing to include the same SO_2 standards for marginal well sites that are currently in NSPS OOOOb.[409] These standards require facilities to remove a specified percentage of SO_2 from acid gas streams, and the required efficiency depends on how much hydrogen sulfide (H_2S) is in the gas and how much sulfur is being processed.[410] The Agency is specifically requesting information on whether sweetening units are located at marginal well sites and whether different standards should be included in NSPS OOOOb for sweetening units located at marginal well sites. (Question III.10b) The EPA is not proposing that sweetening unit presumptive standards be included in EG OOOOc, as they are not a source of methane emissions.

The remainder of this section addressing the proposed standards for marginal wells does not include any discussion of sweetening units or the proposed standards in NSPS OOOOb.

g. NSPS OOOOb and EG OOOOc Requirements and Estimated Impacts for Marginal Well Site Representative Emission Sources

Following are brief summaries of the NSPS OOOOb standards and EG OOOOc presumptive standards for the six emission source types that may be present at marginal well sites.

i. Fugitive Emissions Components

Table 7 provides an overview of the monitoring requirements in NSPS OOOOb and EG OOOOc for each type of well site. If any source of fugitive emissions is identified via the monitoring survey using audible, visual, and olfactory (AVO) methods,

---

[408] 85 FR 57398 (September 15, 2020); 40 CFR 60.5365a(g).
[409] 40 CFR 60.5365b(g).
[410] *See* 40 CFR 60.5405b.

the owner or operator must make a first attempt at repair within 15 days of detection and must complete the repair 15 days after the first attempt. If a leak or malfunction is identified via OGI or Method 21, the owner or operator must make a first attempt at repair within 30 days of detection and must complete the repair 30 days after the first attempt.[411]

Table 7. Overview of NSPS OOOOb and EG OOOOc Fugitive Emissions Component Monitoring Requirements

Well Type	Fugitive Emissions Component Monitoring Requirements[a]
Single wellhead only well site	Quarterly audible, visual, and olfactory (AVO)
Small wellsite	Quarterly AVO monitoring; visual inspection of thief hatches and separator dump valves
Multi-wellhead only well site	Quarterly AVO and Semiannual OGI or Method 21
Well sites or centralized production facilities that contain major production and processing equipment	Bimonthly AVO and visual inspection of thief hatches and separator dump valves; Quarterly OGI or Method 21

[a] 40 CFR 60.5397b(g)(1)/60.5397c(g)(1) allow for the use of AVO or any other detection method, after the initial survey.

ii. Process Controllers

The standards in NSPS OOOOb and presumptive standards in EG OOOOc require zero methane and zero VOC emissions for all controllers at well sites. The exception is for controllers at Alaska sites without access to electrical grid power, where the requirement is to use low-bleed controllers and perform OGI monitoring of intermittent controllers to ensure proper operation.

iii. Pumps

The standards in NSPS OOOOb and presumptive standards in EG OOOOc establish requirements that vary depending on the number of natural gas-driven diaphragm pumps at the well site and whether the site has access to electrical grid power. For any site with access to electrical grid power and for sites without access to electrical

[411] 40 CFR 660.5397b(h)(2).

grid power that have three or more natural gas-driven diaphragm pumps, the standard for all pumps in the affected facility is zero emissions of VOC and methane. For sites without access to electrical grid power that have fewer than three diaphragm pumps (two or one), the standards require owners and operators to route methane and VOC emissions from all natural gas-driven pumps at the affected facility to a process if a VRU is onsite. If a VRU is not onsite, owners and operators must reduce emissions by 95 percent if a control device with at least this emissions reduction capability is already available onsite. If a control device is onsite but is not capable of reducing 95 percent, owners and operators must reduce emission to the maximum extent achievable by the control device.

iv. Oil Well Associated Gas

NSPS OOOOb requires owners and operators to route all associated gas to a sales line, use it for another purpose, or reinject it back into the reservoir or another well, unless they demonstrate that it is technically infeasible. In limited circumstances related to when construction of the well commenced, owners and operators may flare associated gas provided they demonstrate that it is technically infeasible to route the gas to a sales line, capture and use it for another purpose, or reinject it back into the reservoir or another well. In the model rule for EG OOOOc, owners and operators of wells with associated gas methane content of 40 tpy or less may route to a flare. For wells with associated gas contents greater than 40 tpy, owners and operators must route the gas to a sales line, capture it and use it for another purpose, or reinject it back into the reservoir or another well, unless they demonstrate that these options are technically infeasible.

v. Storage Vessels

In both NSPS OOOOb and EG OOOOc, the storage vessel affected/designated facility is the tank battery, which is defined as "a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage

vessel if only one storage vessel is present."[412] Under NSPS OOOOb, if the potential emissions are greater than 6 tpy VOC or 20 tpy methane, owners and operators must route emissions via a closed vent system to a control device that achieves 95 percent reduction or to a flare. Under EG OOOOc, the applicability threshold is 20 tpy methane.

vi. Gas Well Liquids Unloading

Both NSPS OOOOb and EG OOOOc require that owners and operators perform best management practices to minimize or eliminate methane and/or VOC emissions to the maximum extent possible during liquids unloading events that vent emissions to the atmosphere. For unloading technologies or techniques that eliminate venting of emissions during liquids unloading events, NSPS OOOOb and EG OOOOc require only minimal recordkeeping and reporting. For unloading technologies or techniques that could result in venting to the atmosphere, NSPS OOOOb and EG OOOOc require owners and operators to follow work practices. Specifically, owners and/or operators must employ and document best management practices to minimize or eliminate venting of methane and VOC emissions for each gas well liquids unloading operation.

vii. Summary

The EPA evaluated the total cumulative cost impacts of the NSPS OOOOb requirements on the representative marginal well facilities discussed above. Specifically, the Agency estimated the capital costs, the total annual costs (including annualized capital costs and operation and maintenance costs), the VOC and methane emissions reductions, and the cost effectiveness. The Agency then compared the annual costs to the anticipated profits.

The EPA estimated profits for high, mid, and low range price scenarios for marginal wells (*i.e.*, wells that have production equivalent to 15 boe per day or less) using information on production levels and price scenarios from the U.S. EIA. The high-range

[412] 40 CFR 60.5430b (tank battery definition); 40 CFR 60.5430c (tank battery definition).

scenario represents a situation where an owner can sell their oil and gas for a high dollar amount which equates to more profit for the same production volume compared to the mid-range and low-range price scenarios. Table 8 provides these estimates. The Marginal Well TSD for this proposed rule, available in the docket, provides the basis for these profit levels.

Table 8. Estimated Marginal Well Profit Levels

Profit Price Scenario	Profit for Marginal Oil Wells ($/yr)	Profit for Marginal Gas Wells ($/yr)
Low	$28,603	$7,916
Mid	$43,064	$11,793
High	$56,375	$23,274

Table 9 provides an overview of the cost impacts of the NSPS OOOOb standards and EG OOOOc presumptive standards on the representative marginal well facilities presented in the previous sections. The Marginal Well TSD, available in the docket for this proposed rule provides additional detail for these estimated impacts.

Table 9. Impacts of NSPS OOOOb and EG OOOOc on Marginal Well Representative Facilities

Emission Source/ Requirement	Capital Cost ($)	Total Annual Cost ($/yr)	Annual Cost Compared to Marginal Well Mid-Range Profit Price Scenario (%)		Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Cost-effectiveness	
			Oil	Gas			Methane ($/ton)	VOC ($/ton)
Fugitive Emissions - Single Wellhead Only Site: Quarterly AVO	$116	$869	2.0%	7.4%	0.56	0.16	$1,552	$5,431
Fugitive Emissions - Small Well Site: Quarterly AVO	$116	$920	2.1%	7.8%	0.71	0.20	$1,296	$4,600

Emission Source/ Requirement	Capital Cost ($)	Total Annual Cost ($/yr)	Annual Cost Compared to Marginal Well Mid-Range Profit Price Scenario (%)		Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Cost-effectiveness	
			Oil	Gas			Methane ($/ton)	VOC ($/ton)
Fugitive Emissions - Multi-Wellhead Only Site: Semiannual OGI, Quarterly AVO	$1,552	$3,487	8.1%	29.6%	1.83	0.55	$1,910	$6,299
Fugitive Emissions – Well Sites that contain major production and processing equipment: Quarterly OGI and Bimonthly AVO	$1,509	$5,658	13.1%	48.0%	3.94	1.09	$1,435	$6,169
Process Controllers: Zero Emissions[a]	$36,829	$9,019	20.9%	76.5%	2.66	0.74	$3,391	$12,188
Pumps: Route to Existing Control[b]	$8,027	$881	2.0%	7.5%	3.29	0.91	$268	$966
Pumps: Zero Emissions[b]	$32,800	$4,769	11.1%	40.4%	3.46	0.96	$1,378	$4,967
Associated Gas: 95% or Flare[c]	$132,301	$47,411	110.1 %	N/A	10.32	2.87	$4,596	$16,532
NSPS OOOOb: Associated Gas: Route to Sales	$439,922	$89,393	208%	N/A	55.73	15.6	$8,232	$29,613
EG OOOOc: Associated	$439,922	$89,393	52.0% [c]	N/A	55.73	15.6	$8,232	$29,613

Emission Source/ Requirement	Capital Cost ($)	Total Annual Cost ($/yr)	Annual Cost Compared to Marginal Well Mid-Range Profit Price Scenario (%)		Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Cost-effectiveness	
			Oil	Gas			Methane ($/ton)	VOC ($/ton)
Gas: Route to Sales								
NSPS OOOOb: Storage Vessels: 95% or Flare if VOC >6 tpy or Methane >20 tpy	$132,301	$47,411	27.6%[d]	101%[d]	23.75[d]	109.6[d]	$1,996	$432
EG OOOOc: Storage Vessels: 95% or Flare if Methane >20 tpy	$0[e]	$0[e]	n/a[e]	n/a[e]	n/a[e]	n/a[e]	n/a[e]	n/a[e]
Liquids Unloading: Best Management Practices[f]	$0	$739	1.7%	6.0%	0.63	0.18	$1,171	$4,224

[a] Process controllers located at sites in Alaska without access to electricity are allowed to use low-bleed controllers. These estimated impacts only consider well sites subject to zero emissions.

[b] Pumps at well sites with access to electricity, and those with three or more pumps are subject to the zero emissions standard. For pumps at well sites with less than three diaphragm pumps that do not have access to electricity, emissions must be routed to a control device, if there is one on-site (*i.e.*, a new dedicated control device is not required).

[c] NSPS OOOOb requires that all associated gas must either be routed to a sales line or used for another purpose. In limited circumstances related to when construction of the well was originally commenced, flaring is allowed provided there is a demonstration that it is technically infeasible to route the gas to a sales line or use it for another purpose. In the model rule for EG OOOOc, wells with methane contained in the associated gas of 40 tpy or less can be routed to a flare. Wells with associated gas contents greater than 40 tpy must route to sales or use for another purpose. The representative marginal well facility produces associated gas with a methane content of 10.9 tpy, meaning that EG OOOOc would require that it be routed to a flare. It would not be subject to the route to a sales line or used for another purpose requirement. However, higher production marginal wells could produce associated gas with content higher than 40 tpy. For the purpose of this illustration, the production rate for marginal well sites with production levels between 6 and 15 boe per day was used, with estimated potential associated gas emissions level of 55.7 tpy (control would be required). Therefore, the comparison to profits is made based

on the mid-range profit level for marginal oil wells with production levels between 6 and 15 boe per day, which is $171,732 per year.
[d] At the representative marginal well site (< 15 boe/day), storage vessels are not expected to have a PTE greater than 6 tpy VOC or 20 tpy methane. However, for a representative marginal well site with higher production levels (*i.e.*, those with production levels between 6 and 15 boe per day), the estimated VOC emissions are 11.2 tpy and thus would be subject to the NSPS OOOOb standards. Therefore, the comparison to profits is made based on the mid-range profit level for marginal oil wells with production levels between 6 and 15 boe per day, which is $171,732 per year, and the emissions reductions are based on the representative emissions for marginal wells in this range.
[e] Storage vessels at marginal gas well sites are not expected to have a PTE greater than 20 tpy methane and, and thus are not anticipated to incur costs under EG OOOOc.
[f] Both NSPS OOOOb and EG OOOOc require that owners and operators perform best management practices to minimize or eliminate methane and VOC emissions to the maximum extent possible from liquids unloading events that vent emissions to the atmosphere. For unloading technologies or techniques that eliminate venting of emissions during liquids unloading events, NSPS OOOOb and EG OOOOc require minimal recordkeeping and reporting.

Note that the comparison of annual compliance costs to profits in table 9 is on an individual emission source basis. For example, the EPA estimates that the annual compliance costs in the March 2024 Final Rule for fugitive component emissions at well sites or centralized production facilities that contain major production and processing equipment represent 13 percent of the mid-range profits for marginal oil wells and 48 percent of the mid-range profits for marginal gas wells. The cumulative cost impact on an individual marginal well site would be based on adding up all of the costs for all of the specific emission sources at the site. As such, the cumulative annual compliance costs could represent a significant percentage of the profits for a marginal well, even to the extent of exceeding the profits. For example, at a marginal gas well site that contains major production and processing equipment with fugitive components and process controllers, the estimated cumulative annual compliance costs represent over 120 percent of the mid-range profit level. This finding supports the idea that the true cost of compliance with the March 2024 Final Rule for marginal wells is unreasonable. The true cumulative cost of compliance appears to be more than the marginal well subcategory of the industry can bear and survive. Accordingly, the EPA proposes to determine that the collective suite of standards from the March 2024 Final Rule, as applied to marginal

wells, do not together represent the BSER because their collective costs are excessive and unreasonable, as shown in table 9.

h. Control Options for Marginal Well Sites

This section introduces the control options the EPA identified and evaluated for emission sources at marginal oil and natural gas well sites. For each control option for each emissions source, the Agency assessed the cost and emissions reductions and calculated the costs in relation to the associated emissions reduction (*i.e.*, the cost effectiveness). When the cost effectiveness was higher than the Agency has historically considered reasonable for a control option, the EPA is proposing to determine that that option is not viable and the Agency removed it from consideration in the marginal well regulatory options.

Next, the EPA compared the annual costs of the control option to the estimated profit levels for the mid-range price scenario for marginal wells (see table 8). Where the Agency is proposing to determine that the annual cost of a control option, in isolation, was unreasonably high given the mid-scenario profit level (*i.e.*, that the compliance costs of that specific control option represented a sizable portion of the estimated profit), the Agency is proposing that that control option is not cost reasonable and removed it from consideration in the marginal well regulatory options. Note that, later in the regulatory alternatives section (see section III.J.1.i), the EPA further discusses comparisons between the cumulative annual compliance costs of the full well site suite of control requirements in each regulatory alternative and the mid-range profits used to assess the cost reasonableness of the overall compliance package for a marginal well site. In this first step, the EPA is assessing the cost reasonableness of an individual control option for an emission source type to determine whether it should be included as part of the set of alternatives to be further evaluated.

Finally, a factor that the EPA considered in assessing the viability of control options for marginal well sites is the relationship to the requirements in NSPS OOOO and NSPS OOOOa. Emission sources at oil and natural gas well sites constructed, reconstructed, or modified between August 23, 2011, and September 18, 2015, are subject to NSPS OOOO. Emission sources at oil and natural gas well sites constructed, reconstructed, or modified between September 18, 2015, and December 6, 2022, are subject to NSPS OOOOa. Under the EG OOOOc model rule, emission sources constructed, modified, or reconstructed before December 6, 2022, will be designated facilities. Therefore, all NSPS OOOO and NSPS OOOOa affected facilities will also be designated facilities subject to state or federal rules in accordance with EG OOOOc.

This situation is not unique to marginal wells. The EPA discussed this overlap in detail in section VII.C of the preamble for the March 2024 Final Rule.[413] Overall, the Agency concluded that the presumptive standards in EG OOOOc are as stringent as, and in many cases more stringent than, the standards in NSPS OOOO and NSPS OOOOa. The Agency stated that "the EPA concludes that the methane presumptive standards in EG OOOOc will result in the same or greater emission reductions than the VOC and methane standards in previous NSPS KKK, NSPS OOOO, or NSPS OOOOa. Once sources are subject to and in compliance with a state or Federal plan implementing EG OOOOc, and if that plan is just as stringent as or more stringent than the presumptive standards in EG OOOOc, the source will be deemed to comply with the previous respective VOC NSPS, and no longer subject to the methane NSPS, and will comply with only the state or Federal plan implementing EG OOOOc."[414]

The EPA is proposing to not further consider control options for marginal well sites that are less stringent than the NSPS OOOO or NSPS OOOOa requirements. This

[413] 89 FR 16869-71 (March 8, 2024).
[414] 89 FR 16869 (March 8, 2024).

avoids the situation where different standards could apply to different subsets of marginal wells, and the associated confusion about which requirements apply. The Agency therefore removed any such control options from the BSER analysis.

Table 10 provides a summary of the NSPS OOOO and OOOOa requirements for the emission sources at well sites that emit VOC and methane.

Table 10. Summary of NSPS OOOO and NSPS OOOOa Requirements

Emissions Source/Affected Facility	**NSPS OOOO Requirement**	**NSPS OOOOa Requirement**
Fugitive Emissions	No Requirements	Semiannual OGI/Method 21 Monitoring and Repair
Controllers	Low Bleed	Low Bleed
Pumps	No Requirements	Route to Existing Control Device
Associated Gas (Oil Wells Only)	No Requirements	No Requirements
Storage Vessels	95% Control or Flare if Uncontrolled VOC Emissions are 6 tpy or greater[a]	95% Control or Flare if Uncontrolled VOC Emissions are 6 tpy or greater[a]
Liquids Unloading (Gas Wells Only)	No Requirements	No Requirements

[a] The storage vessel affected facility is a single storage vessel.

After the EPA identified the viable control options, the Agency then calculated weighted impacts to reflect the anticipated costs and emissions reductions that would occur, on average, at marginal well sites for all emissions sources at a site. In many cases, only some emission sources are present at a marginal well site (*e.g.*, only some marginal well sites have a natural gas-driven pump). In other cases, an emission source may be present, but the emissions fall below the applicability threshold for the control option being considered. Therefore, the Agency estimated weighted impacts for each control option based on data for marginal wells, where available, and the EPA's technical knowledge regarding the prevalence of the emission source at marginal well sites and the

percentage of sources above specific emission levels for applicability.[415] For more information about the EPA estimates of the fraction of sites with each type of emission source and other information used to develop weighted impacts of the various control options, see the Marginal Well TSD, available in the docket for this proposed rule. The Agency then carried these weighted average impacts for individual control options forward for consideration in the regulatory alternatives (see Section III.K.1.i of this preamble).

i. Fugitive Component Emissions

The EPA identified three control options for fugitive component emissions at marginal well sites: (1) annual AVO monitoring, (2) semiannual AVO monitoring (*i.e.*, twice per year), and (3) quarterly AVO monitoring. In addition, for well sites that contain major production and processing equipment, the Agency considered a fourth option of annual OGI monitoring and quarterly AVO monitoring. Tables 11 and 12 provide the estimated impacts of the control options for each of the marginal well site types. For comparison to the March 2024 Final Rule, these two tables also include control options equivalent to the requirements in NSPS OOOOb.

Table 11. Cost Impacts of Fugitive Component Emissions Control Options for an Individual Marginal Well Site

Control Option	Capital Cost ($)	Annual Cost ($/yr)	Percentage of Mid-Range Profit (Oil Well)	Percentage of Mid-Range Profit (Gas Well)
Single Wellhead Well Site				
Annual AVO	$0	$0	0.0%	0.0%
Semiannual AVO	$116	$549	1.3%	4.7%
Quarterly AVO	$116	$869	2.0%	7.4%
Small Well Site				
Annual AVO	$0	$0	0.0%	0.0%
Semiannual AVO	$116	$574	1.3%	4.9%

[415] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

Control Option	Capital Cost ($)	Annual Cost ($/yr)	Percentage of Mid-Range Profit (Oil Well)	Percentage of Mid-Range Profit (Gas Well)
Quarterly AVO	$116	$920	2.1%	7.8%
Multi-Wellhead Well Site				
Annual AVO	$0	$0	0.0%	0.0%
Semiannual AVO	$202	$667	1.5%	5.7%
Quarterly AVO	$202	$1,091	2.5%	9.3%
Semiannual OGI and Quarterly AVO	$1,552	$3,487	8.1%	29.6%
Well sites that contain major production and processing equipment				
Annual AVO	$0	$0	0.0%	0.0%
Semiannual AVO	$159	$837	1.9%	7.1%
Quarterly AVO	$159	$1,377	3.2%	11.7%
Annual OGI and Quarterly AVO	$1,509	$4,127	9.6%	35.0%
Quarterly OGI and Bimonthly AVO	$1,509	$5,658	13.1%	48.0%

Table 12. Emissions Impacts of Fugitive Component Emissions Control Options on an Individual Marginal Well Site

Control Option	Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Cost-effectiveness	
			Methane ($/ton)	VOC ($/ton)
Single Wellhead Well Site				
Annual AVO[a]	0.00	0.00	N/A	N/A
Semiannual AVO	0.40	0.11	$1,373	$4,991
Quarterly AVO	0.56	0.16	$1,552	$5,431
Small Well Site				
Annual AVO[a]	0.00	0.00	N/A	N/A
Semiannual AVO	0.46	0.13	$1,248	$4,415
Quarterly AVO	0.71	0.20	$1,296	$4,600
Multi-Wellhead Site				
Annual AVO[a]	0.00	0.00	N/A	N/A
Semiannual AVO	0.61	0.17	$1,093	$3,924
Quarterly AVO	0.90	0.25	$1,212	$4,364
Semiannual OGI and Quarterly AVO	1.99	0.55	$1,752	$6,340
Well sites that contain major production and processing equipment				
Annual AVO[a]	0.00	0.00	N/A	N/A
Semiannual AVO	1.84	0.51	$455	$1,644
Quarterly AVO	1.96	0.54	$701	$2,531

Control Option	Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Cost-effectiveness	
			Methane ($/ton)	VOC ($/ton)
Annual OGI and Quarterly AVO	3.52	0.98	$1,172	$4,232
Quarterly OGI and Bimonthly AVO	3.94	1.09	$1,435	$5,169

[a] Based on discussions with industry, the EPA assumes that owners and operators of marginal well sites perform AVO at least annually as part of current practices. Therefore, there would be no impacts due to this option.

As shown in table 10, NSPS OOOOa requires semiannual OGI monitoring at all well sites except for wellhead only sites. On one hand, this could suggest that at least some marginal wells (those subject to NSPS OOOOa) can bear and survive the cost of semiannual OGI monitoring. However, the EPA is considering a less costly standard for marginal wells in this action for NSPS OOOOb and EG OOOOc that is just as effective for emissions reduction purposes, if not more effective than the requirements in NSPS OOOOa. In the March 2024 Final Rule preamble, the Agency provided a conclusion that quarterly AVO is equivalent to, and potentially more effective than, semiannual OGI: "the EPA is concluding that . . . AVO is effective, and therefore OGI is unnecessary, for detecting fugitive emissions from many of the fugitive emissions components at these sites. By requiring more frequent visits to the sites, the final presumptive standard in EG OOOOc would allow earlier detection and repair of fugitive emissions, in particular large emissions from components such as thief hatches on uncontrolled storage vessels. The EPA concludes that the final presumptive standards under the proposed EG OOOOc, which would be quarterly AVO for single wellhead only well sites and small well sites, quarterly AVO and semiannual OGI for multi-wellhead only well sites, and bi-monthly AVO and quarterly OGI for well sites with major production and processing equipment and centralized production facilities would effectively address the fugitive emissions at these well sites and that semiannual OGI monitoring would no longer be necessary for

these well sites. Therefore, these sources need to comply with NSPS OOOOa until they are in compliance with a state or Federal plan implementing EG OOOOc. Once subject to and in compliance with such a plan, then they no longer need to comply with NSPS OOOOa."[416] The EPA is proposing that the conclusion that quarterly AVO is as effective as semiannual OGI applies equally to all marginal well sites, including multi-wellhead marginal well sites, and well sites with major production and processing equipment. For more details on the EPA's comparative analysis of the effectiveness of quarterly AVO and semiannual OGI at marginal well sites, see the Marginal Well TSD, available in the docket for this proposed rule.

Based on this comparison to the NSPS OOOOa standards, the EPA proposes that quarterly AVO is a viable control option for fugitive component emissions at marginal well sites. This option achieves meaningful emission reductions at a cost that is reasonable in isolation at a marginal well site. The Agency also proposes to conclude that annual and semiannual AVO are not the best options, as they result in fewer emissions reductions compared to quarterly AVO, and these options would not be equivalent to the current NSPS OOOOa standards. Therefore, the only control options for fugitive emissions components included in the marginal well regulatory alternatives are 1) quarterly AVO (for all marginal well sites) and 2) annual OGI with quarterly AVO for large marginal well sites and quarterly AVO for all other marginal well sites. In sections III.K.1.i and j, we further consider whether the remaining control options are still reasonable when combined with other costs for other controls at marginal well sites.

ii. Process Controllers

The EPA identified six control options for process controllers: (1) no control, (2) requiring continuous bleed controllers to be low bleed and requiring annual AVO inspections for malfunctioning intermittent vent controllers, (3) requiring continuous

[416] 89 FR 16871 (March 8, 2024).

bleed controllers to be low bleed and requiring semiannual AVO inspections for malfunctioning intermittent vent controllers, (4) requiring continuous bleed controllers to be low bleed and requiring quarterly AVO inspections for malfunctioning intermittent vent controllers, (5) requiring continuous bleed controllers to be low bleed and requiring annual OGI inspections and quarterly AVO inspections for malfunctioning intermittent vent controllers, and (6) requiring zero emission controllers. Tables 13 and 14 provide the estimated impacts of the six control options for a marginal well site.

Table 13. Cost Impacts of Process Controller Control Options for an Individual Marginal Well Site

Control Option	Capital Cost ($)	Annual Cost ($/yr)	Percentage of Mid-Range Profit (Oil Well)	Percentage of Mid-Range Profit (Gas Well)
No Control	$0	$0	0.0%	0.0%
Low-Bleed/Annual AVO	$0	$110	0.3%	0.9%
Low-Bleed/ Semiannual AVO	$0	$220	0.5%	1.8%
Low-Bleed/Quarterly AVO	$0	$439	1.0%	3.6%
Low-Bleed/Annual OGI and Quarterly AVO	$0	$531	1.2%	4.3%
Zero Emissions Controllers	$36,829	$9,019	20.9%	76.5%

Table 14. Emissions Impacts of Process Controller Control Options for an Individual Marginal Well Site

Control Option	Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Methane Cost Effectiveness ($/ton)	VOC Cost Effectiveness ($/ton)
No Control	0	0	N/A	N/A
Low-Bleed/Annual AVO	0.11	0.03	$998	$3,658
Low-Bleed/ Semiannual AVO	0.22	0.06	$998	$3,658
Low-Bleed/Quarterly AVO	0.44	0.12	$998	$3,658
Low-Bleed/Annual OGI and Quarterly AVO	1.63	0.45	$326	$1,176
Zero Emissions Controllers	2.66	0.74	$3,391	$12,240

For the sixth option, requiring zero emission controllers, the EPA considered the comparison of annual costs to the average marginal well profits value to be cost unreasonable. The annual cost of this control option in isolation represents over 73 percent of profits at a marginal gas well site. Thus, the Agency proposes to determine that

zero emission controllers are not a viable control option for marginal well sites. While all five remaining options appear to be viable when evaluated individually, the estimated costs assume that the inspections for process controllers are performed in conjunction with the inspections required for fugitives. Since the EPA is proposing to determine that annual AVO and semiannual AVO are not viable options for fugitives monitoring (see above), the Agency also eliminated them from consideration for process controllers.

As noted previously, the EPA proposes to not further consider control options that are less stringent than the requirements in NSPS OOOO and NSPS OOOOa. Therefore, the only remaining options, which align with the options further considered for fugitives monitoring, are (1) low bleed devices for continuous bleed natural gas-driven pneumatic controllers along with quarterly AVO inspections for intermittent vent natural gas-driven controllers, and (2) low bleed devices for continuous bleed natural gas-driven pneumatic controllers along with quarterly AVO and annual OGI inspections for intermittent vent natural gas-driven controllers.

iii. Pumps

The EPA identified four control options for pumps:(1) no control, (2) routing emissions to an existing control device that achieves 95% emission reduction if one is already available onsite that can accept emissions from the pump, (3) routing emissions to a newly purchased and installed flare (or other control device that achieves 95 percent reduction in VOC and methane emissions) if no existing control device is available, and (4) zero emission pumps. Tables 15 and 16 provide the estimated impacts of the four control options for a marginal well site (assuming one natural gas-driven pneumatic pump per site).

Table 15. Cost Impacts of Pump Control Options for an Individual Marginal Well Site

Control Option	Capital Cost ($)	Annual Cost ($/yr)	Percentage of Mid-	Percentage of Mid-

			Range Profit (Oil Well)	Range Profit (Gas Well)
No Control	$0	$0	0.0%	0.0%
Route to Existing Control	$8,027	$881	2.0%	7.5%
Route to Control (95%)	$132,301	$47,411	110.1%	402%
Zero Emission Pumps for well sites with electricity and sites with 3 or more pumps	$9,371	$1,572	3.7%	13.3%

Table 16. Emissions Impacts of Pump Control Options for an Individual Marginal Well Site

Control Option	Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Methane Cost Effectiveness ($/ton)	VOC Cost Effectiveness ($/ton)
No Control	0.00	0.00	N/A	N/A
Route to Existing Control	3.29	0.91	$268	$966
Route to Control (95%)	3.29	0.91	$14,424	$51,986
Zero Emission Pumps for well sites with electricity and sites with 3 or more pumps	3.46	0.96	$454	$1,638

The EPA considered both the comparison of annual costs to marginal well profits and the cost effectiveness values for the option to route to a new control device to be cost unreasonable. Thus, the Agency proposes to determine that routing to a new control device is not a viable control option for marginal well sites. The EPA also proposes to not further consider the "no control" option as it is less stringent than the standard for pumps in NSPS OOOOa. Therefore, the only viable control options for pumps at marginal well sites that the Agency considered in the regulatory alternatives analysis are: (1) routing emissions to an existing control device that achieves a 95% emission reduction if one is already on site that can accept the emissions from the pump(s), and (2) zero emission pumps for well sites with electricity and sites with 3 or more diaphragm pumps.

iv. Oil Well Associated Gas

The EPA identified four control options for associated gas at marginal oil well sites: (1) no control, (2) routing to an existing control device if one is already on site, (3) routing to a flare (or other control device that achieves 95 percent reduction in VOC and

methane emissions) if potential methane emissions are 20 tpy, or greater (which may require purchasing and installing a new flare if there is not an existing control device), and (4) routing to a control device achieving 95 percent reduction (no threshold). In section III.J.3 of this preamble, the Agency is proposing that routing associated gas to a sales line is not BSER. As such, the EPA did not evaluate routing associated gas to a sales line as a control option for this analysis. However, analysis of this option is available in the marginal well TSD. In section III.J.3 of this preamble, the Agency is also proposing that routing associated gas through a closed vent system to a control device achieving 95 percent reduction is BSER for non-marginal wells. This is equivalent to option 4 in this analysis for marginal wells. The Agency has previously determined that 20 tpy methane emissions is the level below which the costs of flaring storage vessel emissions are not considered reasonable relative to the emissions reductions achieved.[417] In recognition of this, control option 3 is an intermediate option that includes this methane emissions threshold for the requirement to flare associated gas from marginal wells. For this option, no control would be required if uncontrolled methane emissions are less than 20 tpy.

Tables 17 and 18 provide the estimated impacts of the four control options for a marginal well site.

Table 17. Cost Impacts of Associated Gas Control Options for an Individual Marginal Well Site

Control Option	Capital Cost ($)	Annual Cost ($/yr)	Percentage of Mid-Range Profit (Oil Well)
No Control	$0	$0	0.0%
Route to Existing Control	$8,027	$881	2.0%
Route to Control (95%) if > 20 tpy methane	$132,301	$47,411	27.6%[a]
Route to Control (95%) (no threshold)	$132,301	$47,411	110%

[417] 86 FR 63178 (November 15, 2021).

[a] The estimated average methane emissions level from marginal wells with production levels less than 15 boe per day is 10.9 tpy, which would not require control under this option. However, at higher production levels the potential emissions would increase. Based on the average production rate for marginal well sites with production levels between 6 and 15 boe per day, the estimated potential associated gas emissions level is 55.7 tpy (control would be required). Therefore, the comparison to profits is made based on the mid-range profit level for marginal oil wells with production levels between 6 and 15 boe per day, which is $171,732 per year.

Table 18. Emissions Impacts of Associated Gas Control Options for an Individual Marginal Well Site

Control Option	Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Methane Cost effectiveness ($/ton)	VOC Cost effectiveness ($/ton)
No Control	0.00	0.00	N/A	N/A
Route to Existing Control	10.3	2.9	$85	$307
Route to Control (95%) if > 20 tpy methane	53.2.[a]	14.8[a]	$892[a]	$3,207[a]
Route to Control (95%) (no threshold)	10.3	2.9	$4,596	$16,532

[a] Based on the average production rate for marginal well sites with production levels between 6 and 15 boe per day, the estimated potential associated gas emissions level is 55.7 tpy (control would be required). Therefore, the emission reductions and cost effectiveness calculations are based on this level of emissions.

For the fourth option, routing to a control device achieving 95 percent reduction (with no minimum threshold for potential methane emissions), the EPA considered the comparison of annual costs to the average marginal well profits value and proposes to determine that this option is cost unreasonable for a marginal well site. The EPA also reviewed whether routing to an existing control device if one is available is a viable control option for associated gas. At a marginal well site, the flow rate of associated gas to a flare or other control device would likely be significantly larger than that of another emission source. Therefore, an existing control device at a marginal well site that is designed for other emission sources with significantly lower flow rates would be unlikely to be able to handle the higher flows from the associated gas. Thus, the Agency does not anticipate situations where it would be technically feasible to route the associated gas to an existing control device. Given this assumption that it would be technically infeasible

to route associated gas to an existing control device already at a marginal well site in many, if not all situations, the EPA proposes to conclude that including this requirement would add unnecessary burden (due to the associated requirement to demonstrate technical infeasibility if routing to existing control is not technically feasible) without any environmental benefit. Thus, although the cost effectiveness shown in Table 17 for routing to an existing control device is reasonable, the EPA proposes to conclude that routing to an existing control device if one is available is not the best control option for associated gas. The Agency is specifically requesting comment on these assumptions and whether routing to an existing control device should be considered a viable option for associated gas at marginal oil wells. (Question III.10c)

Therefore, the EPA considered the following two control options in the regulatory alternatives for associated gas: (1) no control and (2) routing to a flare (or other control device that achieves 95 percent reduction in VOC and methane emissions) if potential methane emissions are 20 tpy or greater.

v. Storage Vessels

The EPA identified three control options for storage vessels at marginal wells: (1) no control, (2) routing to an existing control device if onsite already, and (3) routing to a flare (or other control device that achieves 95 percent reduction in VOC and methane emissions). Historically, the EPA has determined that 6 tpy VOC and 20 tpy methane emissions are the levels below which the costs of flaring storage vessel emissions are not considered reasonable relative to the emissions reductions achieved for storage vessels.[418] In recognition of this, control option 3 includes this threshold. Specifically, control option 3 is routing to a control device that achieves 95 percent reduction in VOC and methane emissions or to a flare if the uncontrolled VOC emissions are 6 tpy or greater (NSPS OOOOb only) or the uncontrolled methane emissions are 20 tpy or greater (applicable to

[418] 86 FR 63178 (November 15, 2021).

both NSPS OOOOb and EG OOOOc). Under this option, if uncontrolled VOC emissions are less than 6 tpy and uncontrolled methane emissions are less than 20 tpy, the storage vessel tank battery would not be an affected facility under NSPS OOOOb, and if the uncontrolled methane emissions are less than 20 tpy, the storage vessel tank battery would not be a designated facility under EG OOOOc. Thus, no control would be required. This is consistent with the current requirements in NSPS OOOOb and EG OOOOc. Tables 19 and 20 provide the estimated impacts of the three control options on a marginal well site.

Table 19. Cost Impacts of Storage Vessel Control Options for an Individual Marginal Well Site

Control Option	Capital Cost ($)	Annual Cost ($/yr)	Percentage of Mid-Range Profit (Oil Well)
No Control	$0	$0	0.0%
Route to Existing Control	$8,027	$881	2.0%
Route to Control (95%) if > 20 tpy methane[a]	$132,301	$47,411	27.6%[a]

[a] This option would only apply if the potential methane emissions from associated gas are 20 tpy or greater. The representative marginal well facility has uncontrolled emissions from storage vessels of 0.63 tpy methane and 2.9 tpy VOC - thus would not be required to control. However, higher production marginal well sites with high Gas-Oil Ratio (GOR) in the oil/condensate could have emissions that exceed 20 tpy methane or 6 tpy VOC. For the comparison to profits, the annual cost was compared with the mid-range profit for marginal wells with production levels between 6 and 15 boe/day.

Table 20. Emissions Impacts of Storage Vessel Control Options for an Individual Marginal Well Site

Control Option	Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Methane Cost Effectiveness ($/ton)	VOC Cost Effectiveness ($/ton)
No Control	0.00	0.00	N/A	N/A
Route to Existing Control	0.6	2.75	$1,478	$320
Route to Control (95%) if > 20 tpy methane	23.8[a]	109.6[a]	$1,996[a]	$432[a]

[a] This would only apply if the potential methane emissions from associated gas are 20 tpy or greater. The representative marginal well facility has uncontrolled emissions from storage vessels of 0.63 tpy methane and 2.9 tpy VOC - thus would not be required to control. However, higher production marginal well sites with high GOR in the oil/condensate could have emissions that exceed 20 tpy methane or 6 tpy VOC. For the

purpose of the cost effectiveness estimate, an uncontrolled emissions levels of 25 tpy methane and 115 tpy VOC was assumed.

Both the option of no control and the option of routing to an existing control device are less stringent than the requirements in NSPS OOOO and NSPS OOOOa and the EPA proposes to not further consider these options. With regard to the option of routing to a control device that achieved 95 percent reduction if potential methane emissions are greater than 20 tpy, the comparison is not as straightforward because the affected facility definitions differ across rules. Under NSPS OOOO and NSPS OOOOa, a storage vessel affected facility is a single storage vessel that has potential VOC emissions greater of 6 tpy or greater. Under EG OOOOc, the storage vessel designated facility is a tank battery that has potential methane emissions of 20 tpy or greater. Although the standards and presumptive standards all require a 95 percent reduction in emissions, these differences in the applicability could result in a situation where a storage vessel has potential VOC emissions greater than 6 tpy (thus meaning it is an NSPS OOOO or NSPS OOOOa affected facility) but has potential methane emissions less than 20 tpy (thus is not an EG designated facility). In this instance, the storage vessel would continue to be subject to NSPS OOOO or NSPS OOOOa but would not be subject to a state or federal rule via EG OOOOc. However, it would not result in a situation where the same storage vessel is subject to two rules. Therefore, the EPA proposes to conclude that the option of routing to a control device that achieves 95 percent reduction if potential methane emissions are greater than 20 tpy is viable. This is the only control option considered in the regulatory alternatives for storage vessels at marginal well sites.

vi. Gas Well Liquids Unloading

The EPA identified two control options for liquids unloading at marginal gas well sites: (1) no control and (2) best management practices if an unloading technique is used that vents to the atmosphere. Tables 21 and 22 provide the estimated impacts of the two control options for a marginal well site.

Table 21. Cost Impacts of Gas Well Liquids Unloading Control Options for an Individual Marginal Well Site

Control Option	Capital Cost ($)	Annual Cost ($/yr)	Percentage of Mid-Range Profit (Gas Well)
No Control	$0	$0	0.0%
Best Management Practices	$0	$739	6.3%

Table 22. Emissions Impacts of Gas Well Liquids Unloading Control Options for an Individual Marginal Well Site

Control Option	Methane Emission Reduction (tpy)	VOC Emission Reduction (tpy)	Methane Cost Effectiveness ($/ton)	VOC Cost Effectiveness ($/ton)
No Control	0.00	0.00	N/A	N/A
Best Management Practices	0.63	0.18	$1,171	$4,224

The EPA considers both options to be viable. Therefore, (1) no control and (2) best management practices options were considered in the regulatory alternatives analysis.

i. Regulatory Alternatives and BSER Determination

As discussed above in section III.K.1.c of this preamble, the EPA is evaluating BSER at the marginal well site level, considering the combination of emissions reductions, emissions reduction compared to compliance costs (*i.e.*, cost effectiveness), compliance costs compared to profits (*i.e.*, cost reasonableness), and impact on nationwide emissions. This section provides an overview of the regulatory alternatives evaluated, as well as the selection of BSER for marginal well sites.

i. Weighting Factors

As also noted above, the EPA recognizes that there is substantial variation in the equipment and operations at oil and natural gas well sites, even for sites that produce similar amounts of oil and/or natural gas. This BSER analysis considers differences in well sites by using weighted averages of the number and types of emission sources

present.[419] By using weighted averages, the EPA is able to consider the overall impact of different options and alternatives. These weighted averages are based on data, where available, or on our estimates based on knowledge of the industry.[420] The list that follows includes the weighting factors considered in the alternatives analysis.

- Fugitive Emission Components. Fraction of marginal wells sites by well type:
    - Single wellhead – 30 percent
    - Small well – 10 percent
    - Multi-wellhead – 10 percent
    - Well sites with major production and processing equipment – 50 percent
- Process Controllers. Fraction of marginal wells with natural gas-driven controllers – 50 percent
- Pumps. Fraction of marginal well sites with:
    - Natural gas-driven pneumatic pumps – 10 percent
    - Natural gas-driven pneumatic pumps at well sites that have electrical service or at well sites that do not have electrical service but have 3 or more diaphragm pumps – 50 percent
- Associated Gas. Fraction of marginal well sites that are oil well sites and:
    - Have associated gas that is not currently routed to sales – 50 percent
    - Have associated gas with the potential to emit more than 20 tpy methane and that is not currently routed to sales – 10 percent
    - Have associated gas with the potential to emit more than 40 tpy methane and that is not currently routed to sales – 0 percent
- Storage Vessels. Fraction of marginal well sites that are oil well sites and:
    - Have storage vessels – 50 percent
    - Have storage vessels with 20 tpy or more uncontrolled methane emissions – 3 percent
- Liquids Unloading. Fraction of marginal well sites that are gas well sites and have liquids unloading that vents to the atmosphere – 50 percent
- Fraction of marginal well sites with an existing control device – 4 percent

The Marginal Well TSD provides the basis for these factors. The EPA requests comment on the proposed weighting factors used in the BSER analysis. (Question III.10d)

---

[419] EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

[420] U.S. EPA (2026 Marginal Well TSD). Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Proposed Amendments. Marginal Well Technical Support Document (TSD) for the Proposed Amendments to the New Source Performance Standards (NSPS) and Emissions Guidelines (EG). 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). August 2025.

ii. Marginal Well Regulatory Alternatives

Utilizing the weighting factors, the viable control options for each emissions source at a marginal well site were combined into four regulatory alternatives. These regulatory alternatives are summarized below in table 23.

Table 23. Marginal Well Regulatory Alternatives Considered

Regulatory Alternative/ Emissions Source	Requirement
Regulatory Alternative 1	
Fugitive Components	Quarterly AVO
Controllers	Continuous Bleed - Low Bleed Intermittent Vent –Quarterly AVO
Pumps	Route to Existing Control Device
Associated Gas (Oil Wells Only)	No Control
Storage Vessels	95% Control or Flare if Uncontrolled Emissions are 6 tpy or greater VOC or 20 tpy or greater methane
Liquids Unloading (Gas Wells Only)	No Control
Regulatory Alternative 2	
Fugitive Components	Quarterly AVO
Controllers	Continuous Bleed - Low Bleed Intermittent Vent - Quarterly AVO
Pumps	Route to Existing Control Device
Associated Gas (Oil Wells Only)	95% Control or Flare if Methane Content in Associated Gas is 20 tpy or greater
Storage Vessels	95% Control or Flare if Uncontrolled Emissions are 6 tpy or greater VOC or 20 tpy or greater methane
Liquids Unloading (Gas Wells Only)	No Control
Regulatory Alternative 3	
Fugitive Components	Quarterly AVO
Controllers	Continuous Bleed - Low Bleed Intermittent Vent - Quarterly AVO
Pumps	Zero at Sites with Electricity and Sites with 3 or More Pumps, Route to Existing Control Device if No Electricity and Less than 3 pumps
Associated Gas (Oil Wells Only)	95% Control or Flare if Methane Content in Associated Gas is 20 tpy or greater
Storage Vessels	95% Control or Flare if Uncontrolled Emissions are 6 tpy or greater VOC or 20 tpy or greater methane
Liquids Unloading (Gas Wells Only)	Best Management Practices
Regulatory Alternative 4	
Fugitive Components	Quarterly AVO plus Annual OGI at sites with major processing and production equipment
Controllers	Continuous Bleed - Low Bleed

	Intermittent Vent – Annual OGI and Quarterly AVO
Pumps	Route to Existing Control Device
Associated Gas (Oil Wells Only)	95% Control or Flare if Methane Content in Associated Gas is 20 tpy or greater
Storage Vessels	95% Control or Flare if Uncontrolled Emissions are 6 tpy or greater VOC or 20 tpy or greater methane
Liquids Unloading (Gas Wells Only)	No Control

The baseline option (*i.e.*, Regulatory Alternative 1) for all of the marginal well regulatory alternatives is quarterly AVO for fugitive component emissions and process controllers, requirements for low bleed controllers, and routing emissions from pumps to existing control devices. Regulatory Alternative 2 adds control requirements for marginal oil wells with associated gas containing 20 tpy methane or greater and requirements for storage vessels with the potential to emit 20 tpy or greater. Regulatory Alternative 3 then adds BMPs for liquids unloading emissions at marginal gas wells and requirements to install zero emission pumps at sites where electricity is available or that have three or more pumps to the requirements in Regulatory Alternative 2. Regulatory Alternative 4 revises Regulatory Alternative 2 to add a requirement for annual OGI (in addition to quarterly AVO) for large well sites for fugitives and process controllers.

j. BSER Determination

As described in section III.K.1.c of this preamble, the EPA is determining the BSER for marginal wells based on the site-wide impacts and site-wide cost reasonableness. Tables 24 and 25 provide the well-site-wide weighted average impacts for the four regulatory alternatives presented in table 22.

Table 24. Weighted Average Cost Impacts of Marginal Well Regulatory Alternatives

	Weighted Average Capital Cost ($ per marginal well site)	Weighted Average Annual Cost ($/yr per marginal well site)	Weighted Average Annual Cost Comparison to Profit[a]
Regulatory Alternative 1			

Marginal Oil Wells	$3,614	$2,572	6.0%
Marginal Gas Wells	$307	$1,387	11.8%
Regulatory Alternative 2			
Marginal Oil Wells	$10,229	$4,943	11.5%
Marginal Gas Wells	$307	$1,387	11.8%
Regulatory Alternative 3			
Marginal Oil Wells	$11,133	$5,101	11.8%
Marginal Gas Wells	$1,210	$1,914	16.2%
Regulatory Alternative 4			
Marginal Oil Wells	$11,808	$6,522	15.1%
Marginal Gas Wells	$1,885	$2,966	25.1%

[a] Mid-range profit scenario.

Table 25. Weighted Average Emissions Impacts of Marginal Well Regulatory Alternatives

	Weighted Average Methane Emissions Reduction (tpy per marginal well site)	Cost effectiveness ($ per ton of methane reductions)
Regulatory Alternative 1		
Marginal Oil Wells	1.6	$1,597
Marginal Gas Wells	1.6	$869
Regulatory Alternative 2		
Marginal Oil Wells	4.3	$1,158
Marginal Gas Wells	1.6	$869
Regulatory Alternative 3		
Marginal Oil Wells	4.6	$1,108
Marginal Gas Wells	2.2	$853
Regulatory Alternative 4		
Marginal Oil Wells	6.0	$1,091
Marginal Gas Wells	3.3	$898

The EPA considers the annual costs in relation to the annual predicted emissions reductions (*i.e.*, the cost effectiveness as represented in Table 25) to be reasonable for all four regulatory alternatives. Further, the EPA considers the incremental cost effectiveness between Regulatory Alternative 1 and Regulatory Alternative 2, and between Regulatory Alternative 2 and Regulatory Alternative 3, or Regulatory Alternative 4, to be reasonable.

As such, based on an evaluation of the EPA's more traditional cost metric for previous oil and natural gas regulations (cost effectiveness), all alternatives are cost reasonable.

Further, as shown in Table 24, the EPA also considered the annual compliance costs in relation to the profit levels, *i.e.*, the cost reasonableness of each regulatory alternative. First, based on the weighted average impacts, the EPA proposes to conclude that the additional emissions reduction achieved for Regulatory Alternative 2 over Regulatory Alternative 1 is reasonable given the additional costs. Put another way, the EPA ruled out Regulatory Option 1 because there were other cost reasonable alternatives that achieved more emission reductions. In addition, some marginal oil wells could have associated gas methane contents considerably greater than the representative levels assumed in the weighted averages. Regulatory Alternative 2 includes requirements that would cover these higher-emitting situations, whereas Regulatory Option 1 does not.

To further assess the remaining options, the EPA also considered whether the annual compliance costs specifically for large marginal well sites (*i.e.*, those with major production and processing equipment) were cost reasonable in relation to profits. The EPA also considered the profits at two different production levels to evaluate cost reasonableness for both lower production marginal wells (less than or equal to 6 boe per day) and higher production marginal wells (greater than 6 and less than or equal to 15 boe per day). As noted above in section III.K.1.i.i of this preamble, the BSER analysis uses weighted averages of the number and types of emission sources present and assumes that 50 percent of well sites are well sites with major production and processing equipment (*i.e.*, "large" well sites). The remaining well sites are divided between single wellhead, multi-wellhead and small well sites. The EPA notes that most of the differences in requirements (and thus impacts) between Regulatory Alternative 2 and Regulatory Alternatives 3 and 4 only apply to large well sites. Thus, for consideration of whether Regulatory Alternative 3 or 4 is cost reasonable, the EPA specifically considered the total

compliance costs at large well sites. For the regulatory alternatives considered, total site-wide costs for a marginal well site are also expected to be greatest for large well sites due to the presence of major production and processing equipment. Additionally, for these large marginal well sites, the total compliance costs are expected to be even greater for those sites with larger production volumes (*i.e.*, those with greater than 6 boe per day and less than or equal to 15 boe per day) due to the potential to surpass the thresholds being considered that would trigger requirements to control emissions from storage vessels and associated gas. Conversely, the Agency would not expect these compliance costs at large well sites with lower production volumes. The EPA also notes that 86 percent of marginal wells have production volumes less than or equal to 6 boe per day, as discussed in section III.K.1.d of the preamble. Thus, the EPA additionally considered the impacts on these subsets of large well sites. Table 26 compares the unweighted annual costs for large well sites (*i.e.*, well sites that contains major production and processing equipment) with relevant compliance costs assuming equipment as described in large marginal well model plant to the mid-range profit scenario for two different production level groups: marginal wells up to 6 boe per day and marginal wells with greater than 6 and less or equal to 15 boe per day. This additional information provides greater transparency about the cost impacts associated with large well sites.

Table 26. Comparison of Unweighted Annual Costs to Profit for Lower Production (less than or equal to 6 boe/day) and Higher Production (greater than 6 and less than or equal to 15 boe/day) Marginal Well Sites with Major Production and Processing Equipment

	Capital Cost ($ per marginal well site)	Annual Cost ($/yr per marginal well site)	Annual Cost Comparison to Profit[b] for Marginal Wells <= 6 boe/day	Annual Cost Comparison to Profit[b] for Marginal Wells > 6 and < =15 boe/day
Regulatory Alternative 1				
Marginal Oil Wells	$8,186	$2,697	12.6%	1.6%

Marginal Gas Wells	$8,186	$2,697	61.6%	5.7%
Regulatory Alternative 2				
Marginal Oil Wells	$140,487	$50,108	12.6%[c]	29.2%
Marginal Gas Wells	$8,186	$2,697	61.6.%	5.7%
Regulatory Alternative 3				
Marginal Oil Wells	$141,831	$50,799	15.8%[c]	29.6%
Marginal Gas Wells	$9,530	$4,127	94.3%	8.8%
Regulatory Alternative 4				
Marginal Oil Wells	$141,837	$53,200	25.9%[c]	30.8%
Marginal Gas Wells	$9,536	$5,539	126.5%	11.8%

[a] Annual costs assuming marginal wells contain major production and processing equipment and all other emission sources. Also assume that associated gas contains greater than 20 tpy methane (95 percent reduction/flare is required) and that storage vessels have methane emissions less than 20 tpy (no control is required).
[b] Mid-range profit scenario.
[c] As noted previously, the EPA assumes that marginal wells with less than or equal to 6 boe per day will not be above the 20 tpy methane threshold for the requirement to flare associated gas in this option. Thus, the costs associated with flaring of associated gas are not included in the unweighted total costs for comparison to profits for oil wells with less than or equal to 6 boe per day production.

As shown in table 26, the annual compliance costs associated with regulatory options 4 for large marginal well sites are cost unreasonable for the majority of large marginal gas well sites, with costs greater than 125 percent of profits. The EPA considers Regulatory Alternative 3 to also be cost unreasonable with costs greater than 90 percent of profits for the majority of large marginal gas well sites. The EPA also considered the additional emissions reduction of Regulatory Alternative 3 compared to Regulatory Alternative 2. For Regulatory Alternative 2, using the data in tables 23 and 24, the Agency estimates that the emissions reduction per percentage of profits for large marginal gas well sites (for all production levels) is 0.25 tons of methane per percentage of profits. For Regulatory Alternative 3, the incremental reductions from adding best management practices and zero emission pumps drop to only 0.07 tons of methane per additional percentage of profits. Thus, Regulatory Option 2 achieves greater emissions reductions for the cost. Of the remaining options, Regulatory Alternative 2 achieves the greatest emissions reductions, and is cost reasonable. It is thus the best system of emission reduction for marginal well sites.

Therefore, the EPA is proposing Regulatory Alternative 2 for marginal wells. The following subsection provides more detail on the specifics of the proposed requirements.

k. Proposed Marginal Well Requirements

i. Affected/Designated Facility Definition

The affected/designated facility is defined as a marginal well site. The EPA is proposing definitions for both a marginal well and a marginal well site that are based on oil and natural gas production levels.

Specifically, the EPA proposes the following definitions:

Marginal well means a well that produced less than or equal to 15 barrels of oil equivalent per day over the prior 12-month period

Marginal well site means a well site with only marginal wells and the total oil and natural gas produced from all the wells at the site is less than or equal to 15 barrels of oil equivalent per day over the prior 12-month period.

The EPA is also proposing definitions for "non-marginal well" and "non-marginal well site." Specifically, the EPA proposes the following definitions:

Non-marginal well means a well that produced an annual average of greater than 15 barrels of oil equivalent produced per day over the prior 12-month period.

Non-marginal well site means a well site where the total cumulative oil and natural gas produced from all the wells at the site is greater than 15 barrels of oil equivalent per day over the prior 12-month period.

One aspect of these definitions is what constitutes a new marginal well site affected facility subject to NSPS OOOOb and an existing marginal well site designated facility subject to a state or federal plan via EG OOOOc. The EPA is proposing that if any emission source at an existing marginal well site is modified or reconstructed, the entire well site becomes an NSPS OOOOb affected facility (or facilities, if the marginal

status no longer applies post-modification). The specific instances that constitute a modification to an existing marginal well site include the following.

- If a new well is drilled at an existing marginal well site.
- If an existing well at a marginal well site is hydraulically fractured or hydraulically refractured.
- A well at the well site is stimulated in any manner beyond that of normal well maintenance (*e.g.*, acid simulation, recompletion to a new zone) for the purpose of increasing production, including well workover.
- A well at the well site is shut-in for the purpose of increasing production from another well at the site.
- If the number of natural gas-driven process controllers is increased by one or more.
- If a storage vessel is added to a tank battery at an existing marginal well site, if one or more storage vessels at an existing marginal well site are replaced such that the cumulative storage capacity of the existing tank battery increases, or if a tank battery at an existing marginal well sites receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of operations, the addition of a production well, or changes to operations of a production well (including hydraulic fracturing or refracturing of the well).
- If the number of natural gas-driven pumps is increased by one or more.

Another aspect of the marginal well affected/designated facility definition is how owners and operators must demonstrate that production levels are below 15 boe per day. Owners and operators must base this determination on the daily combined oil and natural gas production at the well site for each day during the previous 12 months divided by the number of operating days in the 12-month period. A facility may make this initial

determination at any time. After the facility makes the initial determination that the site has production levels below 15 boe per day, any modification, reconstruction, or action taken that will increase production from one or more wells at the site triggers a requirement to make a new determination. Owners and operators must complete this new determination within 45 days of completion of the activity using information based on the daily average production level from the first 30 days of operation following completion of the activity.

The proposed requirements in NSPS OOOOb and the model rule in EG OOOOc allow facilities to comply with the requirements that apply to marginal well sites after submission of a notification of marginal well site determination. For facilities subject to NSPS OOOOb, if this determination shows that production from the site is above 15 boe per day, the proposed requirements of NSPS OOOOb are that the facility would no longer be a marginal well site affected facility and must comply with the applicable requirements of NSPS OOOOb for affected facilities that are not marginal well site affected facilities by the dates described in 40 CFR 60.5370b. For facilities subject to a state or Federal plan implementing EG OOOOc that completed a modification or reconstruction, the proposed requirements are that the facility would become subject to NSPS OOOOb and must comply with the applicable requirements of NSPS OOOOb for sites that are not marginal well sites by the dates described in 40 CFR 60.5370b. For facilities subject to a state or Federal plan implementing EG OOOOc that did not complete a modification or reconstruction, the proposed model rule in EG OOOOc requires that the facility follow the applicable requirements of EG OOOOc for designated facilities that are not marginal well site designated facilities by the dates described in 40 CFR 60.5370b.

ii. Proposed Standards

The EPA is proposing the same standards for marginal wells in both the NSPS OOOOb and EG OOOOc. The following paragraphs discuss these proposed standards.

For fugitive component emissions, the EPA is proposing to require that owners and operators conduct quarterly AVO inspections to detect any leaking or malfunctioning components. Specifically, the Agency is proposing that AVO inspections must include all fugitive emissions components at the marginal well site, except buried yard piping and associated components (*e.g.*, connectors). The AVO inspections must include a visual inspection of all thief hatches and other openings on storage vessels (or tank batteries) to ensure that they are kept closed and sealed at all times except during times of adding or removing material, inspecting or sampling material, or during required maintenance operations. The AVO inspections must also include a visual inspection of all separator dump valves to ensure the dump valve is free of debris and not stuck in an open position. If leaks or malfunctions are found, a first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using AVO. Repair shall be completed as soon as practicable, but no later than 15 calendar days after the first attempt at repair, subject to delay of repair provisions. If using OGI or Method 21 of appendix A-7 to this part, the first attempt at repair shall be made no later than 30 calendar days after detection of fugitive emissions that were identified and repair shall be completed as soon as practicable, but no later than 30 calendar days after the first attempt at repair.

In addition, the EPA is proposing that these quarterly AVO inspections must include inspections of intermittent vent natural gas driven process controllers to identify situations when the controllers are emitting during idle periods. Specifically, these inspections must include AVO-based inspections of each natural gas-driven intermittent vent process controller to ensure that it is not obviously emitting to the atmosphere during idle periods. Using manufacturers' product information and company-specific

procedures, the inspection must identify indicators of obvious emissions beyond designed de minimis seal seepage rates during idle periods, including audible perception of continuous flow, hissing sounds, and abnormal clicking or chattering; olfactory detection of odors; and visual detection of leaks, cracks, holes, gaps, corrosion, damage, missing pieces, or other visual or physical flow indications of emissions.[421] When monitoring identifies emissions to the atmosphere from a natural gas-driven intermittent vent controller during idle periods, an owner or operator must take corrective action by cleaning, repairing, or replacing the natural gas-driven intermittent vent process controller within 5 calendar days of the date the emissions to the atmosphere were detected. After the repair or replacement of a natural gas-driven intermittent vent process controller, an owner or operator must re-survey the natural gas-driven intermittent vent process controller within five days to verify that it is not venting emissions during idle periods.

Under the EPA's proposal, if continuous bleed natural gas driven process controllers are used, they must have a bleed rate of 6 scf/hour or less. In specific circumstances in which the owner/operator demonstrates that there is a functional need, including but not limited to response time, safety, or positive actuation, continuous bleed process controllers with a bleed rate higher than 6 scf/hour may be used.

For pumps at marginal well sites, the Agency is proposing standards that require that VOC and methane emissions from all natural gas-driven pumps at the marginal well site affected facility be routed to a control device that reduces emissions by 95 percent if a control device with at least this emissions reduction capability is already available onsite, or be reduced by less than 95 percent if a control device is onsite but is not capable of reducing VOC and methane emissions by 95 percent or more. Alternatively,

---

[421] Eben Thoma, OCAP-RAD-MSB (2026). Memorandum to Docket ID No. EPA-HQ-OAR-2025-0163. Examples of Pneumatic Controller Operation, Troubleshooting, and Repair Information.

pump emissions may be routed to a process or pumps not driven by natural gas may be used.

For associated gas, the EPA is proposing that if the methane content in the associated gas produced at the well site is 20 tpy or greater, the associated gas must be routed through a closed vent system to a control device that achieves 95 percent reduction in emissions or greater, or route through a closed vent system to a flare that meets the applicable flare requirements. Well sites with less than 20 tpy methane in the produced associated gas have no control requirements, although a demonstration proving the methane content is less than 20 tpy is required. Note that owners and operators of marginal well sites also can comply by routing the associated gas to a sales line or using it for another purpose.

For storage vessels, the EPA is proposing in NSPS OOOOb that if the potential VOC emissions are 6 tpy or greater or the potential methane emissions are 20 tpy or greater, the emissions must be routed through a CVS to a control device that achieves 95 percent reduction in emissions or greater, or route through a CVS to a flare that meets the applicable flare requirements. For EG OOOOc, this applicability is based only on 20 tpy methane.

Since some well sites are expected to transition between the non-marginal and marginal well site subcategories, there will be situations where a site is already subject to the provisions of NSPS OOOOb or state plans under EG OOOOc that apply to non-marginal well sites prior to making the determination that the well is a marginal well site. In these situations, the EPA is proposing that these well sites would continue to be subject to some requirements specific to non-marginal wells after determining the well site is a marginal well site. There are two circumstances under which owners or operators of a well site that transitions from the non-marginal well requirements to the marginal well requirements would be required to maintain compliance with certain provisions that

apply to non-marginal wells. These circumstances include: the installation of zero emission controllers in accordance with 40 CFR 60.5390b(a) in NSPS OOOOb; and the installation of zero emission pumps in accordance with 40 CFR 60.5393b(a) in NSPS OOOOb. In each of these cases, the owner or operator has already made the capital investment necessary to achieve compliance, and the ongoing costs of maintaining compliance are minimal and potentially negligible. The EPA is proposing the same for the model rule in EG OOOOc (40 CFR 60.5394c(a) and 60.5395c(a)).

Accordingly, the proposed provisions require these emission sources at marginal well sites to continue to meet the more stringent standards, rather than replace compliant equipment with higher emitting natural gas driven controllers or pumps. If additional controllers or pumps are installed at the marginal well site, they must also conform to the zero emission requirements.

I. Request for Comments

As noted in section III.K.1.d of this preamble, the EPA is proposing a single subcategory for marginal well sites based on 15 boe per day. Some industry representatives have suggested that the Agency should create separate subcategories of marginal wells to reflect the differences in production levels, emissions, and profits. One suggestion was that two marginal well subcategories be created: (1) wells with average production levels of 6 boe per day or less, and (2) wells with average production levels greater than 6 and less than or equal to 15 boe per day. Consistent with the approach proposed above for marginal well sites, the EPA is requesting comment on a subcategorization approach to marginal well sites that creates two subcategories of marginal well sites, where there would be different standards for well sites with average production levels of 6 boe per day or less and well sites with average production levels greater than 6 boe and less than or equal to15 boe per day. This subcategorization would likely result in more stringent standards for the higher producing subcategory (with

higher profits) and less stringent standards for the lower emitting subcategory. (Question III.10e) Although stakeholders suggested the aforementioned cut-off levels, the EPA is requesting comment on whether there are other reasonable ways to subcategorize based on production (*e.g.* would subcategories at other production levels be more appropriate) or whether further distinctions may be needed to appropriately target meaningful emissions reductions. (Question III.10f)

The EPA is also soliciting comment on an alternative set of requirements if the EPA establishes two marginal well site subcategories. The Agency is specifically requesting comment on the set of compliance options for a dual subcategory for marginal well sites outlined in the following paragraph. (Question III.10g)

The EPA assessed the previously discussed regulatory alternatives for the two subcategories of marginal well sites described above. Using the same analysis and affordability approach as described in the previous sections, the Agency proposes to determine that if the EPA were to propose two subcategories for marginal well sites of 1) less than or equal to 6 boe per day and 2) greater than 6 boe and less than or equal to 15 boe per day, each subcategory would warrant a different set of standards. Specifically, if the EPA proposed a subcategory of marginal wells with less than or equal to 6 boe per day, the resulting compliance requirements would be similar to the selected option but exclude the requirement to flare associated gas with greater than 20 tpy methane in this subcategory. The EPA would propose that for this subcategory, the control option to flare associated gas would be cost unreasonable and the Agency also does not expect marginal wells in this subcategory to surpass the 20 tpy methane threshold. For the subcategory of marginal wells with production greater than 6 and less than or equal to 15 boe per day the requirements would likely be more stringent. The EPA preliminarily assessed that annual OGI and quarterly AVO for large well sites would be cost reasonable for controlling emissions from fugitives and process controllers for marginal well sites with greater than

6 boe and up to 15 boe per day. For further details on this scenario, see the Marginal Well TSD, available in the in the docket for the proposed rule. In addition, for purposes of setting fugitive emissions monitoring requirements for marginal wells, the EPA seeks comment (including data and detailed information) on how often fugitive emissions are found at marginal well sites, the approximate volume of gas emitted during a typical fugitive emissions event at a marginal well site, estimates regarding the approximate length of time that fugitive events last at marginal well sites, and the cost of conducting fugitive emissions monitoring at a marginal well site (*e.g.*, capital costs, variable costs, changes to business practices, safety implications of conducting the fugitives monitoring, and any other relevant costs)(Question III.10h)

The EPA is also soliciting comment on the cost effectiveness and cost reasonableness of the fugitive emissions monitoring requirements in this proposal for marginal wells. Specifically, the EPA is requesting information on the appropriate frequency, type of monitoring technology, equivalent monitoring technologies for various equipment types, and other relevant information that may improve EPA's cost effectiveness and cost reasonableness analysis, allowing the EPA to better target emission reductions. (Question III.10i) The Agency also seeks comment on whether the fugitive emissions monitoring requirements in NSPS OOOOb and EG OOOOc are necessary for marginal wells considering this information. (Question III.10j)

This proposal also includes proposed instances that constitute a modification to an existing marginal well site. The EPA is seeking comment on what level or type of stimulation for the purposes of increased production could result in increases in emissions. (Question III.10k)

2. Option 2. Subcategorization of Conventional Wells

Another method of characterizing wells is by the resource type; U.S. onshore oil and gas production consists of both conventional and unconventional resources, which

typically require different extraction approaches. Conventional wells are relatively shallow and are drilled vertically (or slightly deviated) to access structural reservoirs with permeability typically sufficient for hydrocarbon flow without intensive stimulation. Unconventional wells extract hydrocarbons from low permeability shale and other tight formations or formations containing viscous oils that resist flow. Unconventional wells can be much deeper and are typically horizontally drilled and hydraulically fractured to create flow. Conventional well production sites usually service single well sites while unconventional well sites trend toward integrated operations that can support up to 10 or more wells. Conventional wells generally operate at lower wellhead pressures and production rates. Unconventional wells exhibit much higher wellhead pressures coupled with high initial hydrocarbon and produced water production rates. Conventional wells typically experience increasing produced water loads over time that must be managed to maintain production.[422, 423, 424] These differences in conventional and unconventional wells are expected to result in differences in the types and amount of equipment at the site and the number of potential emission points. With up to an order of magnitude higher initial well head pressures and high initial flow rates, unconventional well sites can require multistage heated gas, liquid, and water separation, with additional associated components and controls, to properly manage production.[425, 426] In general, the EPA expects that unconventional well sites would have more fugitive components and major production and processing equipment at the site than conventional well sites.

---

[422] Society of Petroleum Engineers (SPE), 2018 (2022), Petroleum Resources Management System, V1.03, ISBN 978-1-61399-994-3.
[423] Omara et al. (2016). Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale Basin. https://doi.org/10.1021/acs.est.5b05503.
[424] Haines et al. (2024). How Quickly Do Oil and Gas Wells "Water Out"? Quantifying and Contrasting Water Production Trends. https://doi.org/10.1007/s11053-024-10308-6.
[425] Boschee, P. (2014). Design of Onshore Production Systems for Unconventional Resources. Oil and Gas Facilities, 3(04), 34-37, https://doi.org/10.2118/0814-0034-OGF.
[426] Conder M. and Schrorer A. (2015). Production Facility Design, Simulation Workflow Optimizes Facility Design For Producing Multiwell Pads. The American Oil and Gas Reporter. https://www.aogr.com/magazine/editors-choice/simulation-workflow-optimizes-facility-design-for-producing-multiwell-pads.

Unconventional muti-well production sites with common header produced water and condensate tank batteries may also have a higher propensity for process upset and malfunction-related emissions compared to conventional sites.[427]

As an alternative to defining a marginal well subcategory based on production levels, the EPA is co-proposing an option to define a conventional well site subcategory based on the type of formation in which the well is drilled. The EPA considered alternative definitions to establish a conventional well site subcategory. One stakeholder noted that conventional wells typically have depths less than 8,000 feet.[428] Supporting information provided by the stakeholder also included a letter asserting that there are fundamental differences between high-GOR shale wells and low-GOR conventional wells and suggested that the EPA classify oil and gas producers into distinct categories using GOR, production rate, and cumulative production as primary indicators.[429] Although GOR and vertical depth could be reasonable indicators of the type of well, the EPA is proposing a definition of unconventional wells that is based on widely accepted resource type and required extraction need descriptions, drawn, in comparison to conventional resources.[430] The EPA believes it is appropriate to base definitions on underlying resource type because the complexity of extraction and surface processing, coupled with production intensity, can differ between resource types, which could lead to differences in emission potential. The Agency is proposing the following definitions associated with this option.

Unconventional formation means a low-permeability geological formation typically composed of shale or other similar fine-grained, organic-rich sedimentary rocks - where oil and natural gas generally remain in the source rock unless natural or artificial fractures occur. Unconventional formations can also include somewhat more porous and permeable formations that contain higher viscosity oils that resist flow. These formations

---

[427] Johnson et al. (2022). Methane emissions from oil and gas production sites and their storage tanks in West Virginia. https://doi.org/10.1016/j.aeaoa.2022.100193.
[428] Berecxo LLC (2025). Letter Mr. Aaron Szabo. Re: Revised Rule-Making Recommendation. October 7, 2025.
[429] Letter to Berexco LLC from Reza Barati. Subject: Recommendation for Categorizing Oil and Gas Producers Based on GOR and Production Characteristics. (September 2, 2025)
[430] SPE (2018)

cannot be produced at economic flow rates or in economic volumes except by vertical or horizontal well bores stimulated by intensive multistage hydraulic fracture treatments or by using multilateral well bores or other techniques to expose more of the formation to the well bore or to generate flow.

Unconventional well means a 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.

Conventional well means any well drilled for the purpose of producing oil or natural gas that is not an unconventional well.

Conventional well site means a well site with only conventional wells.

The EPA is also proposing to add to the definition of "well site" the phrase "this term encompasses both unconventional and conventional well sites." The EPA requests comment on these definitions. (Question III.10l)

A key difference in conventional and unconventional wells is that unconventional wells typically decline quickly and have total productive lives of only 10 to 15 years, in contrast to conventional wells that can remain productive for several decades, often 40 to 50 years or longer.[431] Due to this decline curve, and the long history of conventional vertical well drilling compared to unconventional (primarily horizontal) wells, the vast majority of the lower production wells in operation in the U.S. (> 90 percent) are conventional vertically drilled wells.[432] As a result, the EPA proposes to conclude that the subset of total oil and gas wells that are conventional is largely the same subset of wells that have production levels of 15 boe per day or less (*i.e.*, marginal wells). The EPA is requesting comment on the conclusion that the subset of wells that are marginal largely overlaps with the subset that are conventional wells. (Question III.10m).

Due to this substantial overlap, all the concerns raised by petitioners and industry representatives that are summarized in section III.K.1.b for marginal wells are relevant for conventional wells. Since most conventional wells are lower production wells, these

---

[431] Bouchee (2014).
[432] EIA (2025). The Distribution of U.S. Oil and Natural Gas Wells by Production Rate with Data Through 2024, U.S. Energy Information Administration, U.S. DOE, Washington, DC 20585.

sites will largely have the same concerns about cost and affordability. As noted in this section, the EPA also expects that all conventional well sites will have fewer components and pieces of major production and processing equipment than unconventional well sites. The EPA also expects that the marginal well site representative emission sources are also generally representative for all conventional well sites, as the type of site is expected to correlate with the numbers of components and pieces of major production and processing equipment. Section III.k.1.f describes the well site representative emission sources for marginal wells, which also generally represent sources at conventional well sites. Thus, the Agency would expect conventional well sites to have similar emissions profiles to marginal well sites. Further, all other aspects of the marginal well site BSER analysis discussed in section III.K.1 for marginal well sites are also applicable to conventional well sites.

In conclusion, the EPA finds that the proposed BSER determination for marginal wells presented above in section III.K.1.j of this preamble is also applicable for the conventional well subcategory. Following is a summary of the proposed requirements for conventional wells under Option B.

a. Proposed Conventional Well Requirements

i. Affected/Designated Facility Definitions

The affected/designated well facility is defined as a conventional well site. The EPA is proposing definitions for unconventional formation, unconventional well, conventional well, and conventional well site. These proposed definitions are provided above in the introduction to section III.K.2 of this preamble.

Perhaps the most significant difference between a marginal well site affected/designated facility under Option 1 and a conventional well affected/designated facility under Option 2 is that under Option 2, there would not be a requirement to demonstrate that production levels are below 15 boe per day for each well at the site.

Rather, the owner or operator would only need to provide documentation that the well site meets the definition of a conventional well site. This difference would significantly reduce the regulatory burden associated the determining the correct well site subcategory and associated regulatory requirements as compared to Option 1. The EPA also expects that well sites would not switch between the different well site subcategories (conventional vs. unconventional), as could occur under Option 1, which would provide regulatory certainty for the subsector.

As with Option 1, one aspect is what constitutes a new conventional well site affected facility subject to NSPS OOOOb and an existing conventional well site designated facility subject to a state or federal plan via EG OOOOc. The EPA is proposing that if any emission source at an existing conventional well site is modified or reconstructed, the entire well site becomes an NSPS OOOOb affected facility (or facilities, if the conventional well status no longer applies post-modification). The specific instances that constitute a modification to an existing conventional well site include the following.

- If a new well is drilled at an existing conventional well site.
- If an existing conventional well at a conventional well site is hydraulically fractured or hydraulically refractured.
- A well at the conventional well site is stimulated in any manner beyond that of normal well maintenance (*e.g.*, acid simulation, recompletion to a new zone) for the purpose of increasing production.
- A well at the conventional well site is shut-in for the purpose of increasing production from another well at the site.
- If the number of natural gas-driven process controllers is increased by one or more.

- If a storage vessel is added to a tank battery at an existing marginal well site, if one or more storage vessels at an existing conventional well site are replaced such that the cumulative storage capacity of the existing tank battery increases, or if a tank battery at an existing conventional well sites receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of operations, the addition of a production well, or changes to operations of a production well (including hydraulic fracturing or refracturing of the well).
- If the number of natural gas-driven pumps is increased by one or more.

ii. Proposed Standards

The EPA is proposing the same standards for conventional wells in both the NSPS OOOOb and EG OOOOc. The proposed standards are identical to those proposed for marginal wells discussed above in section III.1.k.ii of this preamble. Table 27 provides a brief summary of these requirements. More detail is provided in section III.1.k.ii of this preamble.

Table 27. Summary of Proposed Standards for Conventional Well Sites Under Option B

Emission Source	Summary of Proposed Standard
Fugitive component emissions	Quarterly AVO and repair of leaks
Continuous bleed natural gas-driven controllers	Low bleed
Intermittent natural gas-driven controllers	Quarterly AVO and repair of malfunctions
Natural gas-driven pumps	Route to a control device that reduces emissions by 95 percent if a control device with at least this emissions reduction capability is already available onsite or be reduced by less than 95 percent if a control device is onsite but is not capable of reducing VOC and methane emissions by 95 percent or more.
Associated gas	If the methane content of the associated gas is 20 tpy or greater, route to a control device that achieves 95 percent reduction in emissions or greater, route to a flare that meets the applicable flare requirements,

	routing to a sales line, use for another purpose, or inject/reinject the gas to a well.
Storage vessels	If the potential VOC emissions are 6 tpy or greater or the potential methane emissions are 20 tpy or greater, the emissions must be routed to a control device that achieves 95 percent reduction in emissions or greater, or route to a flare that meets the applicable flare requirements. For EG OOOOc, this applicability is based only on 20 tpy methane.

In section III.K.1.k.i of this preamble, the EPA is proposing that in situations where a site is already subject to the provisions of NSPS OOOOb, or regulations in a state or federal plan under EG OOOOc, that apply to non-marginal well sites prior to determining the well site is marginal, that those marginal well sites would continue to be subject to some requirements specific to non-marginal wells after determining the well site is a marginal well site. Similarly, the EPA is proposing that in situations where a conventional well site is already operating in compliance with NSPS OOOOb such that the well site already has zero emissions process controllers and pumps, that well site would continue to be subject to the associated standard for that equipment (the installation of zero emission controllers in accordance with 40 CFR 60.5390b(a) in NSPS OOOOb; and the installation of zero emission pumps in accordance with 40 CFR 60.5393b(a) in NSPS OOOOb). Put another way, even after finalization of a new subcategory for conventional wells that includes less stringent standards, those conventional well sites that were previously required to install and operate zero emissions process controllers and pumps would continue to be subject to the more stringent standards for that equipment. However, as the Agency does not expect wells to change from conventional to unconventional or vice-versa, the EPA is not proposing similar provisions in the model rule under OOOOc.

b. Request for Comments

The Option 2 proposal would subcategorize oil and natural gas wells based on the resource type (*i.e.*, conventional or unconventional). Therefore, all conventional wells

would be subject to less stringent standards, without regard to actual production levels. Further, all unconventional wells would be subject to the NSPS OOOOb standards or the EG OOOOc presumptive standards, including the changes finalized as part of this action. The EPA is specifically requesting comment on the following questions. Is our conclusion that most conventional wells are low production and likely have lower emissions than unconventional wells correct? (Question III.10n) If not, what is the prevalence of high production conventional wells that have emissions equivalent to, or higher than, unconventional wells? (Question III.10o) Should all unconventional wells be subject to the more stringent standards even if production is low? (Question III.10p)

In addition, for purposes of setting fugitive emissions monitoring requirements for conventional wells, the EPA seeks comment (including data and detailed information) on how often fugitive emissions are found at conventional well sites, the approximate volume of gas emitted during a typical fugitive emissions event at a conventional well site, estimates regarding the approximate length of time that fugitive events last at conventional well sites, and the cost of conducting fugitive emissions monitoring at a conventional well site (*e.g.*, capital costs, variable costs, changes to business practices, safety implications of conducting the fugitives monitoring, and any other relevant costs).(Question III.10q)

The EPA is also soliciting comment on the cost effectiveness and cost reasonableness of the fugitive emissions monitoring requirements in this proposal for conventional wells. Specifically, the EPA is requesting information on the appropriate frequency, type of monitoring technology, equivalent monitoring technologies for various equipment types, and other relevant information that may improve EPA's cost effectiveness and cost reasonableness analysis, allowing the EPA to better target emission reductions. (Question III.10r)

The Agency also seeks comment on whether the fugitive emissions monitoring requirements in NSPS OOOOb and EG OOOOc are necessary for conventional wells considering this information. (Question III.10s)

This proposal also includes proposed instances that constitute a modification to an existing conventional well site. EPA is seeking comment on what level or type of stimulation for the purposes of increased production could result in increases in emissions. (Question III.10t)

IV. Technical Corrections and Clarifications

Following signature of the March 2024 Final Rule, stakeholders and the EPA identified inadvertent errors that require correction in the regulatory text of NSPSs OOOO, OOOOa, OOOOb, and EG OOOOc, including cross-reference, paragraph designation, typographical errors, and instances with needed clarifications present. The IFR published in August of 2024 ("August 2024 IFR") addressed several of these issues.[433]

Some corrections and clarifications identified prior to the publication of the August 2024 IFR were not included in the August 2024 IFR. Additional corrections and clarifications were also identified after the August 2024 IFR's publication in the *Federal Register*. The EPA proposes additional corrections and clarifications not addressed in the August 2024 IFR with this action. Section IV.A of this preamble includes a discussion of our proposed changes to NSPS subparts OOOO and OOOOa; section IV.B includes a discussion of our proposed changes to NSPS subpart OOOOb; and section IV.C includes a discussion of our proposed changes to EG OOOOc.

A. NSPS Subparts OOOO and OOOOa Technical Corrections and Clarifications

[433] 91 FR 18056 (April 9, 2026).

1. Testing Range Requirement for Manufacturer's Performance Test for Combustion Control Devices

The March 2024 Final Rule prescribes performance testing procedures for control devices. More specifically, 40 CFR 60.5413b(d) and 40 CFR 60.5413c(d) provide a procedure for the performance testing of a control device conducted by the device manufacturer, referred to as the "Manufacturers' Performance Test" (MPT). While not specifically raised by the petitioners, in this proposed rule the EPA proposes an alternative option to clarify the four firing rate settings prescribed.

Currently, 40 CFR 60.5413b(d) prescribes four firing rate settings of (1) 90-100 percent of the maximum design rate of the control device, (2) 70-100-70 percent of the maximum design rate of the control device, (3) 30-70-30 percent of the maximum design rate of the control device, and (4) 0-30-0 percent of the maximum design rate of the control device, where "0 (zero) percent" represents the minimum firing rate of the control device. In this proposed rule, the EPA proposes to clarify that the actual firing rate percent values tested at are approximate (to the extent practicable). The EPA also proposes an alternative to the 0, 30, 70, 90, and 100 percent firing rate settings at the same 70, 90, and 100 percent testing values. The alternative replaces the 0 and 30 percent values with a minimum firing rate achievable in practice by the control device, as well as a firing rate percent equally spaced between the minimum firing rate and the 70 percent firing rate. These proposed changes impact NSPS OOOO (40 CFR 60.5413(d)(2)) and NSPS OOOOa (40 CFR 60.5413a(d)(2)).

The EPA also proposes to clarify that the testing percent values are approximate (to the extent practicable), since owners and operators may not have the ability to achieve testing at an "exact" percent value in practice. Moreover, the EPA proposes to allow an alternative to the prescribed 0 and 30 percent firing rates to perform testing at. The EPA justifies this alternative since on some control devices, based upon the design and

operation of the device, the minimum firing rate may be *greater than* 30 percent of the maximum design rate of the control device. This would render the 30 percent firing rate test moot since a 30 percent firing rate cannot be achieved in practice by the device. By providing this alternative, four firing rates will still be tested, providing a representative range of operation successfully demonstrated by the control device.

2. Connector Monitoring Under NSPS Subparts OOOO and OOOOa

NSPS subparts OOOO and OOOOa point to NSPS subpart VVa for connector monitoring. The connector monitoring provisions in 40 CFR 60.482-11a (Standards: Connectors in gas/vapor service and in light liquid service) that applied to gas processing plants were removed from NSPS subpart VVa. The EPA proposes to incorporate these provisions into NSPS subparts OOOO and OOOOa. These proposed changes correct an omission of requirements that resulted from the connector provisions being removed from 40 CFR 60.482-11a and do not change the requirements that have applied and would apply.

When implementing the changes to incorporate the NSPS subpart VVa connector provisions into NSPS OOOO, the EPA identified an inadvertent error at 40 CFR 60.5400(a). The current regulatory text requires compliance with the requirements of 40 CFR 60.482-1a(a), (b), and (d) and did not cite paragraph (e) which includes the < 300 hours per year in service exclusion. The EPA proposes to change the current regulatory text to require compliance with the requirements of 40 CFR 60.482-1a(a), (b), (d) and (e). This proposed change is consistent with NSPS OOOOa and with the record requirement cited in 40 CFR 60.486a (now included in 40 CFR 60.542(c)(4)(ii)). These changes are made in 40 CFR 60.5400, 60.5401, 60.5421, and 60.5422 of NSPS subpart OOOO, and 60.5400a, 60.5401a, 60.5421a, and 60.5422a of NSPS subpart OOOOa.

3. CBI Email Address

The EPA proposes to update the CBI email address in NSPS subpart OOOOa at 40 CFR 60.5420a(b)(9)(i)(A) and 60.5420a(b)(11)(i) to reflect a change of address to *ocapcbi@epa.gov*.

4. Cross-Reference Technical Correction

The EPA proposes to revise 40 CFR 60.5420a(b)(7)(ii)(C) "[section] 60.5397a(c)(1), (2), and (7), and (c)(8)(i)" to "[section] 60.5397a(c)(1), (2), and (7), and (c)(8), or (d)" to correct an inadvertent cross-reference error.

The EPA also proposes to revise 40 CFR 60.5400(a) "requirements of §§ 60.482-1a(a), (b) and (d)," to "requirements of §§ 60.482-1a(a), (b), (d) and (e)". This revision corrects an inadvertent omission of a citation to recordkeeping requirements that are included in the parallel provisions of NSPS OOOOa (see 40 CFR 60.5400a(a)).

Red line and strike-out versions of the corrected regulatory language for NSPS subparts OOOO and OOOOa are available in Docket ID No. EPA-HQ-OAR-2025-0163.

B. NSPS Subpart OOOOb Technical Corrections and Clarifications

1. Testing Range Requirement for Manufacturer's Performance Test for Combustion Control Devices

The March 2024 Final Rule prescribes performance testing procedures for control devices. More specifically, 40 CFR 60.5413b(d) and 40 CFR 60.5413c(d) provide a procedure for the performance testing of a control device conducted by the device manufacturer, referred to as the "Manufacturers' Performance Test" (MPT). While not specifically raised by the petitioners, in this proposed rule the EPA proposes an alternative option to clarify the four firing rate settings prescribed. These proposed changes impact NSPS OOOOb (40 CFR 60.5413b(d)(2)). *See* Section V.A.1 of this preamble for more information.

2. NHV Sampling

In the April 2026 Reconsideration Final Rule, the EPA expanded the scope of streams not subject to the March 2024 Final Rule's NHV monitoring requirements to include all flares and ECDs at both new and existing sources.[434] More specifically, the Agency prescribed that NHV continuous monitoring sampling and the alternative performance test (sampling demonstration) are required only where there are contributions from inert gases or other miscellaneous scenarios that decrease NHV content, and the EPA concluded that such scenarios can be validated and documented through the physical presence or absence of process equipment, process piping, engineering analysis, or process flow diagrams.[435, 436]

Since publishing the April 2026 Reconsideration Final Rule, the EPA has learned that some owners and operators interpret the NHV sampling provisions to require monitoring whenever any inert gas contribution or other scenario reduces NHV, even when the combined stream remains well above the appliable minimum NHV value. This reading of the regulatory text is not consistent with the EPA's intent for the April 2026 Reconsideration Final Rule. Such an interpretation would essentially eliminate the monitoring exemptions for flares and ECDs finalized in the April 2026 Reconsideration Rule in situations where minor dilutions have no realistic potential to lower NHV below the required threshold. After reviewing this issue, including a request for confirmation submitted by GPA Midstream Association,[437] the EPA agreed and determined that the regulatory text did not consistently convey the intended monitoring trigger.[438] As a result, the Agency proposes to update and clarify the regulatory text, where applicable, to consistently indicate that the prescribed NHV sampling requirements are required only

[434] 91 FR 18056 (April 9, 2026).
[435] 91 FR 18056 (April 9, 2026).
[436] 91 FR 18077 (April 9, 2026).
[437] GPA Midstream Association (GPA) (2026). Letter to EPA, et al. from GPA Midstream Association. Re: Docket ID No. EPA-HQ-OAR-2024-0358; Request for Confirmation Regarding Net Heating Value Monitoring and Reporting Requirements in 40 CFR Part 60, Subparts OOOOb/c. June 23, 2026.
[438] 91 FR 18082 (April 9, 2026).

where there are contributions from inert gases or other miscellaneous scenarios that may lower the NHV of the combined stream below the applicable minimum NHV value, and not just when contributions from inert gases or other miscellaneous scenarios are simply introduced into the process. That is, where an owner or operator can document, using reasonable process knowledge or engineering analysis, that an added stream does not have the potential to lower the combined inlet gas below the applicable minimum NHV value, the flare or ECD would thereby not be subject to the continuous NHV monitoring requirements in 40 CFR 60.5417b(d)(8)(ii) nor the alternative NHV monitoring sampling demonstration in 40 CFR 60.5417b(d)(8)(iii). The EPA notes that without this clarification, the current regulatory text could be interpreted to provide that any stream or scenario that lowers the NHV by any amount, even if the combined stream remains comfortably above the applicable minimum value, disqualifies a flare or ECD from the monitoring exemptions provided in the April 2026 Reconsideration Final Rule. The changes proposed herein would also be consistent with the preamble to the April 2026 Reconsideration Final Rule where the EPA stated its intent, in its updates to the qualifying NHV sampling requirements, that "it is the EPA's understanding that operators have various means of making this determination on an operating history, best engineering judgement, or manufacturer's recommendation basis as a response to known operating scenarios that could lower the NHV below the applicable minimum value."[439]

Moreover, this proposal would also align with the EPA's existing requirement that the NHV sampling be performed "at the highest [inert] percentage possible" at 40 CFR 60.5417b(d)(8)(iii)(F) and (G), 40 CFR 60.5420b(b)(11)(v)(I), and 40 CFR 60.5420b(c)(11)(vi). These proposed clarifications would be made to NSPS OOOOb at 40 CFR 60.5417b(d)(8)(ii), 40 CFR 60.5417b(d)(8)(iii), 40 CFR 60.5417b(d)(8)(iii)(F), and 40 CFR 60.5420b(c)(11)(vi).

---

[439] *Id.*

3. CBI Email Address

The EPA proposes to update the CBI email address in NSPS subpart OOOOb at 40 CFR 60.5398b(d)(1) and 60.5413b(d)(12) to reflect a change of address to *ocapcbi@epa.gov*.

4. Electronic Reporting

In this proposal, the EPA is proposing minor updates to the semi-annual and annual compliance report spreadsheets for NSPS OOOOb sources submitted through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). These updates pertain to the reporting requirements included in this proposal, as well as the finalized April 2026 Reconsideration Final Rule.[440]

A draft version of the proposed templates for these reports is included in the docket for this action. The EPA specifically requests comment on the content, layout, and overall design of the template(s). (Question IV.1)

5. Cross-Reference, Paragraph Designation, and Typographical Technical Corrections

Table 28 (Cross-Reference, Paragraph Designation, and Typographical Technical Corrections to 40 CFR Part 60, subpart OOOOb) includes the sections and paragraphs of each identified error, the corrections proposed in this action, and the reasoning for the corrections.

Table 28. Cross-reference, Paragraph Designation, and Typographical Technical Corrections to 40 CFR Part 60, Subpart OOOOb

Section and Paragraph	Technical Correction and Reason for Change
60.5370b(a)(5)(i)	Revised "may comply with [section] 60.5390b(b)(1)" to "may comply with [section] 60.5390b(d)(1)" to correct an inadvertent cross-reference error.

[440] 91 FR 18056 (April 9, 2026).

60.5370b(c)	Deleted 40 CFR 60.5370b(c). This paragraph is included in 40 CFR 60.5360b(c).
60.5386b(a)	Revised "[section] 60.5380b(a)(3) through (6)" to "[section] 60.5380b(a)(4) through (7)" to correct inadvertent cross-reference errors.
60.5397b(d) introductory text	Revised 40 CFR 60.5397b(d) introductory text to reflect referencing to three paragraphs instead of two; "(d)(1) through (3)" instead of "(d)(1) and (2)." Revised 40 CFR 60.5397b(d)(2) by splitting into two paragraphs, 40 CFR 60.5397b(d)(2) and (3). This correction was made to be consistent with NSPS OOOOa.
60.5398b(b)(2)(vi)	Revised the last sentence of 40 CFR 60.5398b(b)(2)(vi) from "[t]he provisions of [section] 60.5397b(d)(3) do not apply" to "[t]he provisions of [section] 60.5397b(c)(3) do not apply" to correct an inadvertent cross-reference error.
60.5400b(h)(2)(ii)(A)	Changed period to a semi-colon to correct a typographical error so it reads as follows: "(A) Repack the existing valve with a low-e packing;"
60.5401b(a), (f), and (h); 60.5402b(b), (c), and (e); and 60.5415b(j)(1)	Revised "in gas/vapor service and in light liquid service" to "in gas/vapor service or in light liquid service" to be consistent with other references in NSPS OOOOb.
60.5401b(i)	Removed 40 CFR 60.3401b(i) section paragraph (second one) due to an inadvertent duplication of the section paragraph.
60.5403b(e)	Revised "[s]amples used in conjunction with paragraph (d) and (e) of this section" to "[s]amples used in conjunction with paragraph (d) of this section and [section] 60.5402b(d)" to clarify alternative heavy/light liquid service requirements.
60.5410b(c)(2)(i)	Revised "[section] 60.5377(g)" to "[section] 60.5377b(g)" to correct an inadvertent typographical error.
60.5410b(j)(10)	Revised the second sentence of the regulatory text from "complying with [section] 60.112b(d)(a)(1) or (2)" to "complying with [section] 60.112b(a)(1) or (2)" to correct an inadvertent typographical error.
60.5398b(d)(1) introductory text and 60.5413b(d)(12) introductory text	Updated CBI email address in the cited introductory section paragraphs in two places to reflect a change in the email address.
60.5415b(f)(3)	Removed 40 CFR 60.5415b(f)(3) section paragraph (first one) due to an inadvertent duplication of the section paragraph.
60.5415b(l)	Revised 40 CFR 60.5415b(l) introductory paragraph descriptor by deleting "[c]ontinuous compliance" and replace it with "[f]ugitive emissions components affected facility." This change corrects an inadvertent error and is consistent with other descriptors in the section.
60.5420b(a)(4)	Revised paragraph so that "of (5) decimals of a degree" is clearly included as part of paragraph (a)(4). This change is a paragraph format change.
60.5420b(b)(2)(xv) and 60.5420b(c)(1)(vi)(A)	Revised "in order the make that claim, including" to "in order to make that claim, including." This edit corrects an inadvertent typographical error.

60.5420b(b)(7)(i)	Revised "each process controller that is driven by natural gas, as required by [section] 60.5390b(d), that allows traceability" to "each process controller that is driven by natural gas that allows traceability" to remove an inadvertent incorrect cross-reference.
60.5420b(b)(8)(vii) second sentence	Revised "each storage vessel that that" to "each storage vessel that." This edit corrects an inadvertent typographical error.
60.5420b(b)(8)(ix)	Revised last sentence from "information in (b)(8)(iii) through (vii) of this section" to "information in (b)(8)(iii) through (viii) of this section" to correct an inadvertent cross-reference error.
60.5420b(b)(9)(ii)(C)	Revised "[section] 60.5397b(c)(1), (2), and (7), (c)(8)(i), or (d)" to "[section] 60.5397b(c)(1), (2), and (7), (c)(8), or (d)" to correct an inadvertent cross-reference error.
60.5430b Process controller definition	"Process controller" definition order in list of definitions corrected to reflect alphabetical order to correct an inadvertent placement of the definition in the list of definitions.

6. Clarifying Technical Corrections

This action also proposes technical corrections to clarify erroneously included language in the regulatory text (or in some cases, erroneously omitted). Table 29 (Clarifying Technical Corrections to 40 CFR part 60, subpart OOOOb) includes the sections and paragraphs of each identified error, the corrections proposed by this action, and the reasoning for the corrections.

Table 29. Clarifying Technical Corrections to 40 CFR Part 60, Subpart OOOOb

Section and Paragraph	Clarifying Technical Correction and Reason for Change
60.5370b(a)(1)	Revised to better clarify the compliance date for when an owner or operator is complying with the alternative requirement to replace reciprocating compressor rod packing every 8760 hours. Specifically, the EPA proposes to revise 40 CFR 60.5370b(a)(1) introductory text to add "or as an alternative, with the requirements in [section] 60.5385b(d)," and 40 CFR 60.5370v(a)(1)(ii) to delete "and (d)(3)."
60.5377b(b), (c), (f)(1), (f)(2), (g) introductory text, (g)(1), and (g)(3)	Revised "paragraph [or paragraphs] (a)(1) through (4) of this section" to "paragraph (a)(1), (2), (3), or (4) of this section" to distinguish that an owner or operator is required to comply with one and not all compliance options. These edits clarify conditional applicability.
60.5400b(a) introductory text	a. Revised the first sentence from "for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service, and connector in gas/vapor or light liquid service, as applicable" to "for each pump in light liquid service, each pressure relief device in gas/vapor service, each valve in gas/vapor or light liquid service, and each connector in gas/vapor or light liquid service, as applicable." b. Revised the third sentence from

	"for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service" to "for each pump, each valve, and each connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service." These corrections clarify that requirements apply to each component type in service, as applicable.
60.5401b(f)	Revised "each valve in gas/vapor and in light liquid service" to "each valve in gas/vapor and each valve in light liquid service" to clarify that requirements apply to each valve.
60.5410b(c)(1)	a. Revised "[section] 60.5377b(a)," to "[section] 60.5377b(a)(1), (2), (3), or (4)," and b. Revised "[section] 60.5420b(c)(3)(i), (ii), and (iv)" to "[section] 60.5420b(c)(3)(i), and (ii), as applicable, and submit the information required by [section] 60.5420b(b)(4)(i) through (v) in your initial annual report." These edits correct an inadvertent cross-reference error, clarify conditional applicability, and are consistent with edits and parallel requirements in EG OOOOc.
60.5415b(d)(2)	Revised by splitting it up into three separate subparagraphs (i) through (iii) based on each compliance option type. This proposed change increases clarity without changing requirements and is consistent with 40 CFR 60.5415c(c)(1).
60.5415b(i)(3)	Revised to add "as applicable" in order to clarify conditional applicability. Specifically, changed "complying with paragraphs (i)(6), (7), (9), and (10) of this section" to "complying with paragraphs (i)(6), (7), (9), and (10) of this section, as applicable."
60.5416b(b)(1)(i)	Revised to add "[e]xcept as specified in paragraph (b)(1)(ii) of this section," to the beginning of the first sentence. The EPA included this addition to clarify exception from specified requirements for covers and CVSs located at onshore natural gas processing plants which are specified in 40 CFR 60.5416c(b)(1)(ii).
60.5420b(b)(9)(ii)(C)	Revised "[a]ny deviations from the monitoring plan elements under [section] 60.5397b(c)(1), (2), and (7), (c)(8)(i), or (d)" to "[a]ny deviations from the monitoring plan elements under [section] 60.5397b(c)(1), (2), and (7), (c)(8), or (d). This revision clarifies that monitoring plan elements include the elements specified in paragraphs (c)(8)(i) through (iv) and not just (c)(8)(i).
Table 2 to subpart OOOOb of Part 60—Alternative Technology Periodic Screening Frequency at Well Sites and Centralized Production Facilities Subject to AVO Inspections and/or Semiannual OGI or EPA Method 21 Monitoring	Added footnote that sources located on the Alaska North Slope normally subject to annual monitoring under 40 CFR 60.5397b(g)(1)(vi) must meet the periodic screening frequency of this table if they choose to demonstrate compliance using periodic screenings. This addition clarifies which periodic screening frequencies sources on the Alaska North Slope must meet.

A red line and strike-out version of the corrected regulatory language for NSPS OOOOb is available in Docket ID No. EPA-HQ-OAR-2025-0163.

C. EG Subpart OOOOc Technical Corrections and Clarifications

1. Testing Range Requirement for Manufacturer's Performance Test for Combustion Control Devices

The March 2024 Final Rule prescribes performance testing procedures for control devices. More specifically, 40 CFR 60.5413b(d) and 40 CFR 60.5413c(d) provide a procedure for the performance testing of a control device conducted by the device manufacturer, referred to as the "Manufacturers' Performance Test" (MPT). While not specifically raised by the petitioners, in this proposed rule the EPA proposes an alternative option to clarify the four firing rate settings prescribed. These proposed changes impact EG OOOOc (40 CFR 60.5413c(d)(2)). *See* Section IV.A.1 of this preamble for more information.

2. NHV Sampling

In the April 2026 Reconsideration Final Rule, the EPA expanded the scope of streams not subject to the March 2024 Final Rule's NHV monitoring requirements to include all flares and ECDs at both new and existing sources. More specifically, the Agency prescribed that NHV continuous monitoring sampling and the alternative performance test (sampling demonstration) is required only where there are contributions from inert gases or other miscellaneous scenarios that decrease NHV content.

Since publishing the April 2026 Reconsideration Final Rule, the EPA has learned that some owners and operators interpret the NHV sampling provisions to require monitoring whenever any inert gas contribution or other scenario reduces NHV, even when the combined stream remains well above the applicable minimum NHV value. As a result, the Agency proposes to update and clarify the regulatory text, where applicable, to consistently indicate that the prescribed NHV sampling requirements are required only

where there are contributions from inert gases or other miscellaneous scenarios that may lower the NHV of the combined stream below the applicable minimum NHV value, and not just when contributions from inert gases or other miscellaneous scenarios are simply introduced into the process.

Moreover, this would also align with the EPA's existing requirement that the NHV sampling be performed "at the highest [inert] percentage possible" at 40 CFR 60.5417c(d)(8)(iii)(F) and (G), 40 CFR 60.5420c(b)(10)(v)(I), and 40 CFR 60.5420c(c)(10)(vi). These proposed clarifications would be made to EG OOOOc at 40 CFR 60.5417c(d)(8)(ii), 40 CFR 60.5417c(d)(8)(iii), 40 CFR 60.5417c(d)(8)(iii)(F), 40 CFR 60.5417c(d)(8)(iii)(G), 40 CFR 60.5420c(b)(10)(v)(I), and 40 CFR 60.5420c(c)(10)(vi). See section IV.B.2 of this preamble for more information.

3. CBI Email Address

The EPA proposes to update the CBI email address in EG OOOOc at 40 CFR 60.5413c(d)(12) and 60.5420c(d)(1) to reflect a change of address to *ocapcbi@epa.gov*.

4. Electronic Reporting

In this proposal, the EPA is proposing minor updates to the semi-annual and annual compliance report spreadsheets for EG OOOOc sources submitted through the EPA's CDX using the CEDRI. These updates pertain to the reporting requirements included in this proposal, as well as the finalized April 2026 Reconsideration Final Rule.[441]

A draft version of the proposed templates for these reports is included in the docket for this action. The EPA specifically requests comment on the content, layout, and overall design of the template(s). (Question IV.2)

5. Cross-Reference, Paragraph Designation, and Typographical Technical Corrections

[441] 91 FR 18056 (April 9, 2026).

Table 30 (Cross-Reference, Paragraph Designation, and Typographical Technical Corrections to 40 CFR Part 60, subpart OOOOc) includes the sections and paragraphs of each identified error, the corrections proposed in this action, and the reasoning for the corrections.

Table 30. Cross-reference, Paragraph Designation, and Typographical Technical Corrections to 40 CFR Part 60, Subpart OOOOc

Section and Paragraph	Technical Correction and Reason for Change
60.5396c(b)(1)(ii)	Revised 40 CFR 60.5396c(b)(1) by deleting 60.5396(b)(1)(ii) and renumbering subparagraphs. This correction of an inadvertent error provides consistency with NSPS OOOOb.
60.5397c(d)	Revised 40 CFR 60.5397c(d) introductory text to reflect referencing to three paragraphs instead of two; "(d)(1) through (3)" instead of "(d)(1) and (2)." Revised 40 CFR 60.5397c(d)(2) by splitting into two paragraphs, 40 CFR 60.5397b(d)(2) and (3). This correction provides consistency with NSPS OOOOa.
60.5398c(b)(2)(vi)	Revised the last sentence of 40 CFR 60.5398b(b)(2)(vi) from "[t]he provisions of [section] 60.5397c(d)(3) do not apply" to "[t]he provisions of [section] 60.5397c(c)(3) do not apply" to correct an inadvertent cross-reference error.
60.5398c(b)(5)(v), first sentence	Revised the first sentence from "in accordance with § 60.5416c(b)(4), except" to "in accordance with § 60.5416c(b)(5), except" to correct an inadvertent cross-reference error.
60.5401c(a) (seventh sentence), (f) introductory text, (h) introductory text, and (h)(1); 60.5402c(b) introductory text, (c), and (e).	Revised "in gas/vapor service and in light liquid service" or "in gas/vapor and light liquid service" to "in gas/vapor service or in light liquid service" to be consistent with other references in EG OOOOc.
60.5405c(a) introductory text	Revised 40 CFR 60.5405c(a) introductory text to make the following cross-reference corrections: a. Replaced "[section] 60.5393c(b)(1)(iii), (b)(2)(i), or (c)(2)(iv) with "[section] 60.5393c(a) or (b)" to correct an inadvertent cross-reference error; and b. Replaced "[section] 60.5392c(a)(2)(i)(A)" with "[section] 60.5392c(a)(1) or (2)" to correct an inadvertent cross reference error.
60.5410c(h)(4)	Revised "within 180 days after initial startup, or within 180 days 36 months after the [S]tate plan submittal deadline" to "within 180 days after initial startup, or within 36 months after the State plan submittal deadline." This corrects an inadvertent typographical error by removing the second "180 days."

60.5410c(h)(10)	Revised "You must submit a statement that you are complying with [section] 60.112b(d)(a)(1) or (2)" to "You must submit a statement that you are complying with [section] 60.112b(a)(1) or (2)." This corrects and inadvertent typographical error by removing "(d)."
60.5412c(a) introductory text	Revised 40 CFR 60.5412c(a) introductory text from "[a]s an alternative to paragraphs (a)(1) through (3) of this section, you may install a control device" to "[a]s an alternative to paragraph (a)(1) of this section, you may install a combustion control device." These revisions fix inadvertent errors and are consistent with NSPS OOOOb.
60.5413c(d)(12) introductory text and 60.5420c(d)(1)	Updated CBI office name and email address in 40 CFR (d)(12) introductory text and in 40 CFR 60.5420c(d)(1) to reflect revised email address.
60.5415c(j) introductory descriptor	Revised descriptor by deleting "[c]ontinuous compliance" and replace it with "[f]ugitive emissions components designated facility." This change corrects an inadvertent error and is consistent with other descriptors in the section.
60.5430c Acid gas definition	"Acid gas" definition removed from definitions. Sweetening units are not covered under EG OOOOc. This removes a definition that is not needed in EG OOOOc.
60.5430c Process controller definition	"Process controller" definition order in list of definitions corrected to reflect alphabetical order to correct an inadvertent placement of the definition in the list of definitions.
60.5430c Total Reduced Sulfur definition	"Total reduced sulfur" definition removed from definitions. Sweetening units are not covered under EG OOOOc. This removes a definition that is not needed in EG OOOOc.
60.5430c Total SO_2 equivalents	"Total SO_2 equivalents" definition removed from definitions. Sweetening units are not covered under EG OOOOc. This removes a definition that is not needed in EG OOOOc.

6. Clarifying Technical Corrections

This action also proposes technical corrections to clarify erroneously included language in the regulatory text (or in some cases, erroneously omitted). Table 31 (Clarifying Technical Corrections to 40 CFR Part 60, subpart OOOOc) includes the sections and paragraphs of each identified error, the corrections proposed by this action, and the reasoning for the corrections.

Table 31. Clarifying Technical Corrections to 40 CFR Part 60, Subpart OOOOc

Section and Paragraph	Clarifying Technical Correction and Reason for Change
60.5363c(a)(1) and (2)	Revised to clarify in both paragraphs (a)(1) and (2) that, for purposes of the inventory of designated facilities and emissions from designated facilities in a State, the prescriptive requirements of 40 CFR 60.25a(a) do not apply. Specific revisions change the regulatory text of paragraphs (a)(1) and (2) from "subpart, [section] 60.25a(a) does not apply" to "subpart, the emissions inventory requirements of [section] 60.25a(a) do not apply." These changes are consistent with the EPA's intent as specified in the March 2024 Final Rule Preamble.[442]
60.5400c(a) introductory text	a. Revised the first sentence from "or each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service, and connector in gas/vapor or light liquid service, as applicable" to "or each pump in light liquid service, each pressure relief device in gas/vapor service, each valve in gas/vapor or light liquid service, and each connector in gas/vapor or light liquid service, as applicable." b. Revised the fourth sentence from "for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service" to "for each pump, each valve, and each connector in heavy liquid service and each pressure relief device in light liquid or in heavy liquid service." These corrections clarify that requirements apply to each component type in service, as applicable.
60.5401c(a) introductory text	Revised 40 CFR 60.5401c(a) introductory text (sixth sentence) from "for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service" to "for each pump, each valve, and each connector in heavy liquid service and each pressure relief device in light liquid or in heavy liquid service." These corrections clarify that requirements apply to each component type in service, as applicable.
60.5401c(f)	Revised "each valve in gas/vapor and in light liquid service" to "each valve in gas/vapor and each valve in light liquid service" to clarify that requirements apply to each valve.
60.5415c(i)(1) introductory text	Revised 40 CFR 60.5415c(i)(1) introductory text from "each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor and light liquid service and connector in gas/vapor and light liquid service as required by § 60.5400c(b)" to "each pump in light liquid service, each pressure relief device in gas/vapor service, each valve in gas/vapor or in light liquid service and each connector in gas/vapor or in light liquid service as required by § 60.5400c(b)." These changes clarify that each component in service, as applicable, are required to conduct monitoring.
60.5415c(i)(8)	Revised 40 CFR 60.5415c(i)(8) from "for each valve in gas/vapor or light liquid service" to "for each valve in gas/vapor and each valve in light liquid service." These changes clarify that an owner or operator much conduct monitoring of each valve in both gas/vapor and light liquid service.

[442] 89 FR 17006 (March 8, 2024).

Section and Paragraph	Clarifying Technical Correction and Reason for Change
60.5415c(i)(9)	Revised 40 CFR 60.5415c(i)(9) from "each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service" to "each pump, each valve, and each connector in heavy liquid service and each pressure relief device in light liquid service or each pressure relief device in heavy liquid service." These changes clarify that an owner or operator must conduct monitoring of each component in service, as applicable.
60.5415c(i)(10)	Revised 40 CFR 60.5415c(i)(10) from "each connector in gas/vapor or light liquid service" to "each connector in gas/vapor service or each connector in light liquid service." These changes clarify that an owner or operator must conduct monitoring of each connector in gas/vapor and light liquid service.
60.5416c(a) introductory text	Revised 40 CFR 60.5416c(a) introductory text from "each cover according to the procedures" to "each cover, as applicable, according to the procedures" to clarify and acknowledge that not all sources have covers.
60.5416c(b)(1)(i)	Revised 40 CFR 60.5416c(b)(1)(i) to add "[e]xcept as specified in paragraph (b)(1)(ii) of this section," to the beginning of the first sentence. This addition clarifies exception from specified requirements for covers and CVSs located at onshore natural gas processing plants which are specified in 40 CFR 60.5416c(b)(1)(ii).
Table 3 to subpart OOOOc of Part 60—Alternative Technology Periodic Screening Frequency at Well Sites and Centralized Production Facilities Subject to AVO Inspections and/or Semiannual OGI or EPA Method 21 Monitoring	Added footnote that sources located on the Alaska North Slope normally subject to annual monitoring under 40 CFR 60.5397c(g)(1)(vi) must meet the periodic screening frequency of this table if they choose to demonstrate compliance using periodic screenings. This addition clarifies which periodic screening frequencies sources on the Alaska North Slope must meet.

A red line and strike-out version of the corrected regulatory language for EG OOOOc is available in Docket ID No. EPA-HQ-OAR-2025-0163.

V. Appendix K

A. Summary of Provisions Promulgated in March 2024 Final Rule

In the March 2024 Final Rule, the EPA finalized 40 CFR Part 60, Appendix K as the monitoring survey requirement to monitor for leaks using OGI at onshore natural gas processing plants subject to NSPS OOOOb. The EPA also included Appendix K in the

model rule (presumptive standards) in EG OOOOc for the same purpose. Appendix K, which is the protocol used to determine whether a source has a VOC and/or GHG leak using OGI, was also finalized as part of the March 2024 Final Rule. Put another way, in the March 2024 Final Rule, the EPA promulgated a new appendix to part 60 (Appendix K), which the Agency then allowed to be used in a new NSPS that the Agency promulgated at the same time (NSPS OOOOb). However, the appendix is broader than just NSPS OOOOb and could be used for other subparts in 40 CFR part 60, as appropriate. The Appendix K protocol covers surveys of process equipment using OGI cameras in sectors where the majority of constituents (>75 percent by volume) in the emissions streams have a response factor (as defined in Appendix K, section 3.0) of at least 0.25, when compared to the response factor of propane, and can be imaged by the equipment specified in section 6.0 of Appendix K.[443]

B. Petitioners' Concerns and Supporting Information, Summary of Proposed Changes, and Basis for Proposed Changes

Petitioners' Concerns and Supporting Information. Reconsideration petitioners requested that the EPA allow existing gas processing plants (*i.e.*, gas plants that are currently subject to either NSPS OOOO, OOOOa, or KKK) to utilize OGI with Appendix K in lieu of EPA Method 21 monitoring. [444] Currently, NSPS OOOO and OOOOa sources must follow the EPA Method 21 procedures specified by NSPS VVa in 40 CFR 60.485a, and NSPS KKK sources must follow the EPA Method 21 procedures specified by NSPS VV in 40 CFR 60.485. The reconsideration petitioners claim that the March 2024 Final Rule allows for States to incorporate this compliance option into their State

[443] For more information on what the EPA finalized in the March 2024 Final Rule on this topic, *see* 89 FR at 16827 and 17013-17016.

[444] GPA Midstream Association (GPA) (2025). Letter to Jodi Howard, US Environmental Protection Agency, from GPA Midstream Association. Re: Reconsideration of Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. July 24, 2025.

plans under EG OOOOc. However, they asserted that operators should be allowed to use this compliance option now, prior to full implementation of EG OOOOc via either a State or federal plan. Moreover, in their view, the EPA has demonstrated that OGI with Appendix K is an acceptable alternative to traditional EPA Method 21 monitoring and there should not be a time delay on when operators can start implementing such programs.[445]

Petitioners also claimed that because the applicability of NSPS is on a process unit basis, gas processing plants often have some units subject to NSPS KKK, OOOO, or OOOOa and other units subject to OOOOb, which allows the use of Appendix K, OGI, or EPA Method 21, creating inconsistent compliance options and confusion within a given oil and natural gas facility.

Petitioners argued that OGI with Appendix K is a viable option for certain operators, reducing personnel time spent on complying with LDAR inspection requirements and removing the obligation to tag and maintain an inventory of all components at a facility. Petitioners asserted that, due to the demonstrated equivalency of the two methods (*i.e.*, OGI and EPA Method 21), there should be no delay in allowing OGI with Appendix K to be implemented at existing facilities subject to NSPS OOOO, OOOOa, and KKK.

Summary of Proposed Changes. In the March 2024 Final Rule, the EPA limited the Appendix K "advanced technology" option as a novel approach to the rules they were actively promulgating (*i.e.*, NSPS OOOOb and EG OOOOc), and did not reopen NSPS OOOO, OOOOa, or KKK in that action.[446] In this reconsideration proposal, the EPA proposes regulatory revisions to provide the option for owners and operators to perform OGI surveys conducted according to Appendix K for NSPS OOOO, OOOOa, and KKK

[445] 89 FR 17013-14 (March 8, 2024).
[446] The Appendix K protocol may be applied to other sources only when incorporated through rulemaking to a specific subpart.

gas processing facilities. Under this proposal, consistent with the provisions in NSPS OOOOb and the model rule in EG OOOOc for gas processing facilities, if the "Appendix K option" is chosen, facilities would need to monitor for equipment leaks using OGI in accordance with Appendix K, at a bimonthly survey frequency, with any emissions observed using OGI defined as a leak. These proposed changes would be made to NSPS OOOO (40 CFR 60.5401 and 60.5421), NSPS OOOOa (40 CFR 60.5401a and 60.5421a), and NSPS KKK (40 CFR 60.632 and 60.635), consistent with the provisions already included in NSPS OOOOb (40 CFR 60.5400b and 60.5421b) and EG OOOOc (40 CFR 60.5400c and 60.5421c).

Basis for Proposed Changes. These proposed revisions provide additional flexibility for the regulated community by expanding the option to use OGI surveys conducted according to Appendix K for all eligible facilities. The EPA further notes that operators could currently seek approval to use Appendix K on an operator-by-operator basis through the CAA section 111(h)(3) Alternative Means of Emission Limitation (AMEL) process, but if multiple requests for the same technology occur, using the AMEL process would be less efficient and more burdensome as opposed to adding the Appendix K option NSPS OOOO, NSPS OOOOa, and NSPS KKK, as described earlier, for both the regulated community and the EPA.

Moreover, the EPA found in the March 2024 Final Rule that bimonthly OGI conducted according to the procedures in Appendix K provides equivalent or greater emissions reduction in comparison to EPA Method 21 conducted according to NSPS VV and VVa (which is required under NSPS OOOO, OOOOa, and KKK) for gas processing plants.[447] Based on this information included in the March 2024 Final Rule record, the EPA proposes to find that allowing owners and operators the option to use Appendix K instead of EPA Method 21 will result in equivalent or better emissions reductions. As

[447] 89 FR 17013-14 (March 8, 2024).

such, the EPA proposes that Appendix K is an appropriate alternative to allow in these scenarios.

As stated in the preamble to the March 2024 Final Rule, the EPA also intends for the Appendix K protocol to have broad applicability, where Appendix K would have applicability to facilities when specified in a referencing subpart of 40 CFR part 60 to help determine the presence and location of leaks (but is not applicable for use in direct emission rate measurements from sources). That is, the Appendix K protocol does not on its own apply to any sources; it applies only where a specific rule subpart adopts it by reference and specifies the sources to which it applies. In this case, the EPA proposes to expand the use of the Appendix K protocol implementing the standards for process units at existing natural gas processing plants subject to NSPS KKK, OOOO, and OOOOa.

If the EPA finalizes this proposal, once incorporated into subparts KKK, OOOO, and OOOOa, the limitations and requirements that currently apply to Appendix K would also apply to its use for purposes of these subparts. For example, as described in the March 2024 Final Rule, the protocol would only be applicable for surveys of process equipment using OGI cameras where the majority of compounds (>75 percent by volume) in the emissions streams have a response factor of at least 0.25 when compared to the response factor of propane. Additionally, the OGI camera used for surveying must also be capable of detecting (or producing a detectable image of) methane emissions of 19 grams per hour (g/hr) and either butane emissions of 29 g/hr or propane emissions of 22 g/hr at a viewing distance of 2.0 meters and a delta-T of 5.0 ^{o}C in an environment of calm wind conditions around 1.0 meter per second or less. Verification that the OGI camera meets these criteria may be performed by the owner or operator, the camera manufacturer, or a third party.[448] Additional requirements would also apply, as described

[448] *Id.*

in the March 2024 Final Rule.[449] However, the EPA notes that no changes to the Appendix K procedures are being proposed in this action.

VI. Summary of Cost, Environmental, and Economic Impacts

In accordance with the requirements of Executive Order 12866, the EPA assessed the costs, environmental, and economic impacts associated with this proposed rulemaking. These results are presented in detail in the RIA accompanying this proposed rulemaking. This analysis is entirely distinct from the statutory BSER considerations proposed herein and is presented solely for the purposes of complying with Executive Order 12866.

The EPA estimated present values (PV) and equivalent annualized values (EAV) of the estimated increase in economic surplus of this proposed reconsideration and co-proposal in 2024 dollars over the 2027 to 2050 period, discounted to 2025.[450] Estimated increases in economic surplus include reductions in compliance cost expenditures from industry, as well as increased value to consumers from lower commodity prices and revenues to industry from increased production. Surplus changes also account for the forgone value of natural gas captured as a result of less stringent compliance obligations. Changes beyond compliance cost savings are represented by the Savings from Energy Market Impacts values. The aspect of the proposed reconsideration reflected in the quantitative analysis are the subcategorization and standard setting for marginal well sites and removal of route to sales as the BSER for associated gas. The aspects of the co-proposal reflected in the quantitative analysis are the subcategorization and standard

---

[449] *Id.*

[450] The EPA has used economic surplus metrics in previous rulemakings; for example, *see* Section VII.A of "National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants," 75 FR 54970 (September 9, 2010). While not as commonly used as social cost metrics derived from engineering cost approaches, surplus metrics are often preferred because they attempt to account for aspects of market behavior that engineering cost approaches ignore.

setting of conventional well sites and removal of route to sales as the BSER for associated gas.

Table 32 presents the estimated additional economic surplus of this proposed reconsideration and co-proposal in 2024 dollars for the baseline which includes the March 2024 Final Rule (*i.e.*, the primary baseline analyzed in the RIA). This table presents the PV and EAV of these estimates discounted at three percent and seven percent.

Table 32. Present Value and Equivalent Annualized Value of Increased Economic Surplus Estimates of the Proposed Action, Discounted to 2025 (Millions of 2024 Dollars), 2027-2025[a]

		3 Percent Discount Rate		7 Percent Discount Rate	
		PV	EAV	PV	EAV
Proposed Reconsideration	Compliance Cost Savings[b]	$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
Co-Proposal	Compliance Cost Savings[b]	$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

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] The Compliance Cost Savings rows include the change in value of product recovery.

Table 33 summarizes the emissions changes associated with the proposed reconsideration and co-proposal over the 2027 to 2050 period. Emissions changes are presented for three categories: methane, VOC, and HAP. As is further explained in sections 5.2 and 7.4 of the RIA, there are a number of parts of EPA's analysis of the RIA that may have resulted in overestimation of foregone emission reductions. The limitations noted in section 5.2 also existed in the 2024 RIA thus creating a similar potential that those emission reductions were overestimated.

Table 33. Total Projected Emissions Changes under the Proposed Additional Reconsideration Option, 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

[a] Numbers rounded to two significant digits unless otherwise noted. Values represent the increase in emissions over the baseline. 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.

The EPA requests comment on the modeling assumptions, data inputs, and methodological choices used in the accompanying RIA, including assumptions around site equipment assignment, annual operating costs, and production decline rates. (Question VII.1)

VII. Request for Comments

The EPA seeks to solicit comments on this proposed action. In addition to general comments on this proposed action, the EPA solicits comment and responses to specific questions related to the proposed changes. For convenience, the EPA provides a summary of these questions in table 34. In addition to the specific questions below, the EPA solicits comments on other changes to the March 2024 Final Rule that could further unleash U.S. energy dominance by increasing the amount of oil and gas that can be produced consistent with the best reading of applicable statutory requirements. The EPA is broadly seeking comment on any and all of the requirements established in the March 2024 Final Rule not discussed elsewhere in today's proposed rulemaking. More specifically, the EPA is interested in comments regarding any or all changes (whether by amendment or repeal) that could be made to the March 2024 Final Rule that would relieve unnecessary regulatory burden or remedy inconsistencies with the best reading of the Clean Air Act. As part of this broader comment solicitation, the EPA is focused on

potential changes to: (1) BSER determinations for individual affected or designated facilities that the EPA has not otherwise requested comment on; (2) the underlying standards of performance, emission guidelines, or other related requirements (e.g. monitoring and recordkeeping) for those facilities; and (3) any other issues or concerns that may more broadly impact key assumptions that underlie multiple BSERs, standards of performance, or the emission guidelines established in the March 2024 Final Rule. Commenters are encouraged to provide information and data in support of any comments received. In response to information and data received, the final rule may revise, expand, or eliminate the standards or requirements in the March 2024 Final Rule.

Table 34.- List of Questions

Question Number	Question
I.1	The EPA solicits comments on its proposed regulatory changes. Within this preamble, the EPA is also soliciting broader comment on further issues relative to the March 2024 Final Rule and resulting NSPS OOOOb and EG OOOOc, including both the additional issues raised by reconsideration petitioners for which the EPA is not proposing regulatory changes at this time and any additional issues commenters believe are relevant to the lawfulness, reasonableness, or implementability of the March 2024 Final Rule.
III.1a	The EPA seeks comment providing additional studies and information bearing on super-emitter events and corresponding strategies to address them, including whether the EPA should treat them separately as a regulatory manner in the first instance and, if so, whether and which threshold the EPA should use to separately consider such events
III.2a	Liquids Unloading: the EPA proposes that the NSPS OOOOb and EG OOOOc continue to require that owners and operators maintain records of the identification of each well (i.e., U.S. Well ID or U.S. Well ID associated with the well affected facility) that conducts a gas well liquids unloading operation during the reporting period without venting of methane and/or VOC emissions and the non-venting gas well liquids unloading method used. These records, which EPA understands would already be retained as part of normal site operations records/documentation, do not constitute a burdensome requirement. The EPA solicits comment on this proposal.
III.2b	Liquids Unloading: The EPA is also soliciting comment on repealing part or all of the recordkeeping and reporting requirements for liquids unloading in OOOOb, and the corresponding presumptive requirements in EG OOOOc and EG OOOOc. The Agency's ICR associated with the 2024 Final Rule anticipated that the recordkeeping and reporting burdens associated with liquids unloading would increase significantly over the first three years of implementation. The EPA seeks comment on whether those projected costs have materialized, and if so, which provisions are the most burdensome. (Question III.2b)
III.3a	Process Controllers: The EPA proposes intermittent controller requirements with quarterly OGI monitoring for process controllers on high pressure systems at compressor stations for modified and reconstructed facilities under NSPS OOOOb and for the presumptive standards in the EG OOOOc model rule. The EPA solicits comment on this proposal.

III.3b	Process Controllers: The EPA is proposing a different standard only for existing sources that would be required to retrofit equipment to comply with the NSPS OOOOb standards (*i.e.*, modified and reconstructed facilities) and the EG OOOOc presumptive standards, but is not proposing an alternative or different standard for newly constructed facilities (*i.e.*, for sources subject to NSPS OOOOb that were not previously existing sources that then modified or reconstructed). The EPA is soliciting comment on this aspect of the proposal, including whether additional or alternative standards or subcategories for sources subject to NSPS OOOOb are merited and whether the EPA's premise regarding cost equivalency in the design and initial planning phases is accurate.
III.3c	Process Controllers: The EPA is soliciting comment on the actuation pressure which best categorizes these high-pressure systems and whether additional subcategories are merited. Industry representatives have suggested using 100 psig as a general guideline for the level of pressure at which different types of process controllers, and actuators in particular, become more costly than the equipment needed for lower pressure levels. However, the EPA is interested in any information that may suggest that another or additional pressure levels would be better suited to delineate the subcategory or further subcategories.
III.3d	Process Controllers: The EPA is soliciting additional information on the relative change in emissions when process controller replacement events occur and the frequency with which they occur. The EPA also requests comment on whether the existing modification determination language appropriately captures changes in emissions increases, or whether adjustments to the current criteria are needed to reflect industry practices, such as clarifying what constitutes net increases in emissions from the source.
III.3e	Process Controllers: The EPA solicits comment on whether it would be appropriate to consider broader flexibility for process controllers. The EPA asks for additional information and data related to cost and technical feasibility of retrofits, routing to new or existing control devices, and challenges related to electricity access. The EPA also requests comment on recordkeeping, retention, and reporting requirements related to process controllers and . whether it is appropriate to repeal the zero emission standard for process controllers under NSPS OOOOb and EG OOOOc.
III.4a	Fugitive Emissions: The EPA proposes to amend 40 CFR 60.5397b(g)(2) and (3) and 40 CFR 60.5397c(g)(2) and (3) to include difficult- and unsafe-to-monitor provisions for AVO inspections that parallel those in the current rules for monitoring with EPA Method 21. The EPA solicits comment on this proposal.
III.4b	For purposes of setting fugitive emissions monitoring requirements, the EPA seeks comment (including data and detailed information) on how often fugitive emissions are found at different types of sites, the approximate volume of gas emitted during a typical fugitive emissions event at each type of site, estimates regarding the approximate length of time that fugitive events last at these sites, and the cost of conducting fugitive emissions monitoring (e.g., capital costs, variable costs, changes to business practices, safety implications of conducting the fugitives monitoring, and any other relevant costs). .
III.4c	The EPA is soliciting comment on the cost effectiveness and cost reasonableness of monitoring requirements for fugitive emissions generally. The EPA is specifically requesting information on the appropriate frequency, type of monitoring technology, equivalent monitoring technologies for various equipment types, and other relevant information that may improve EPA's cost effectiveness and cost reasonableness analyses, allowing the EPA to better target of emission reductions and EPA also seeks comment whether the fugitive emissions monitoring requirements in the March 2024 Final Rule are necessary considering this information. The EPA also seeks comment on whether further distinctions or subcategorizations may be needed to appropriately target meaningful

	emissions reductions in a cost reasonable manner, including potential exemptions of certain subcategories.
III.4d	Fugitive Emissions: This proposal does not include revisions to add references to NSPS OOOO, NSPS OOOOa or NSPS OOOOb in 40 CFR 60.5430c. The EPA solicits comment on this proposal.
III.4e	Fugitive Emissions: Modification criteria for centralized production facility proposal. The EPA proposes to amend the definitions of "well site" and "centralized production facility" to clarify the difference between a well site and a centralized production facility with respect to the receipt of liquids from one or more offsite natural gas or oil production wells. The EPA also proposes to amend the modification criteria in 40 CFR 60.5365b(i)(2) to describe the activities that would be classified as a modification at a centralized production facility for purposes of 40 CFR 60.5397b and 60.5398b. The EPA solicits comment on this proposal.
III.4f	Fugitive Emissions: The EPA proposes to amend the well closure provisions at 40 CFR 60.5397b(l)(2) and 60.5397c(l)(2), and 40 CFR 60.5420b(a)(4)(ii) and 60.5420c(a)(3)(ii) to allow facilities the option to submit a notification after the well closure is complete. The EPA solicits comment on this proposal.
III.5a	While the EPA is not proposing any specific changes related to the application of LPE limit criteria in this action, the EPA is soliciting comment from stakeholders and the public on this specific issue. Depending on the comments the Agency receives, the EPA may take further action at an appropriate time, and related, solicits further comment on whether the 2024 LPE criteria should be repealed.
III.5b	Storage Vessels: The EPA proposes to amend the modification provisions at 40 CFR 60.5365b(e)(3)(ii)(C), to delete the reference to centralized production facilities. The EPA also proposes to amend 40 CFR 60.5365b(e)(3)(ii)(D) to treat centralized production facilities the same as compressor stations and onshore natural gas processing plants for the purposes of determining if a modification has occurred. The EPA also proposes to amend 40 CFR 60.5365b(e)(2)(ii) to delete the reference to centralized production facilities, and to amend 40 CFR 60.5365b(e)(2)(iii) to add the reference to centralized production facilities. The EPA proposes similar edits in EG OOOOc at 40 CFR 60.5386c(e)(2)(ii) and (iii). The EPA solicits comment on these proposed changes.
III.5c	Storage Vessels: The EPA solicits comment on whether revising the LPE limit criteria in NSPS OOOOb and EG OOOOc to match the language used in NSPS OOOO and NSPS OOOOa would lead to unmitigated emissions increases and/or loopholes.
III.5d	Storage Vessels: The EPA solicits comment on whether maintaining the LPE limit criteria included in the March 2024 Final Rule but clarifying that a VOC emissions limit may serve as a surrogate for methane emissions where VOC and methane are present in the emissions stream would lead to unmitigated emissions increases and/or loopholes.
III.5e	Storage Vessels: The EPA solicits comment on whether revising the calculation required for the PTE to be a 12-month rolling average to be more consistent with air permitting standards, such as title V would lead to unmitigated emissions increases and/or loopholes.
III.5f	Storage Vessels: The EPA solicits comment on whether removing reporting requirement in 40 CFR 60.5365b(e)(2)(i)(F), but continue to require owners and operators to maintain records and make them available upon request would lead to unmitigated emissions increases and/or loopholes.
III.5g	Storage Vessels: The EPA solicits comment on whether removing the requirement in 40 CFR 60.5365b(e)(2)(i)(C) for performance testing to establish parametric limits and the associated requirements in 40 CFR 60.5365b(e)(2)(i)(D) to do continuous compliance monitoring of those parametric limits would lead to unmitigated emissions increases and/or loopholes.
III.5h	Storage Vessels: The EPA solicits comment on whether maintaining the LPE limit criteria included in the March 2024 Final Rule but clarifying that

	operators may use an LPE production limit that accounts for annual production decline in combination with an operational limit would lead to unmitigated emissions increases and/or loopholes.
III.5i	Storage Vessels: The EPA is also requesting comments on the real world impact of the current LPE requirements on storage vessel applicability determinations, including information: on (1) the number of storage vessels that could become subject to NSPS OOOOb or EG OOOOc solely because existing state permits or regulatory requirements do not include all six elements of the current LPE limit definition despite these vessels having actual emissions below the applicable VOC or methane thresholds; (2) the cost to operators and state agencies of revising existing permits and regulations to meet the current six element criteria; (3) whether existing state permitting programs achieve equivalent environmental outcomes to the federal LPE criteria without the specific elements at issue; (4) the timeline required for states to amend their permitting and regulatory programs to incorporate the current LPE limit criteria; and (5) finally, whether in light of these considerations, the LPE criteria under the 2024 Final Rule should be repealed.
III.5j	Storage Vessels: The EPA solicits comment on information regarding explosions of a NSPS OOOOb storage vessel affected facility as well as any near misses.
III.5k	Storage Vessels: The EPA solicits comment on whether an owner or operator of a storage vessel affected facility should be exempt from operating a control device when a shut-in occurs and whether there are additional work practices that could be put in place to minimize emissions during these events
III.5l	Storage Vessels: The EPA solicits comment on the change in emission profile of a storage vessel affected facility after a shut-in and whether the shut-in emission profile is under 6 tpy of VOC or 20 tpy of methane.
III.5m	Storage Vessels: The EPA solicits comment on whether sites subject to a temporary shut-in could recalculate their PTE to determine the need for storage vessel control.
III.5n	Storage Vessels: The EPA solicits comment on whether sites subject to a temporary shut-in could be subject to an alternative standard (tons per day of VOC/tons per day of methane) to determine the need for storage vessel control.
III.6a	Covers and Closed Vent Systems: The EPA proposes that covers and CVSs on well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment affected facilities used to comply with the requirements to route to a process or to control, as applicable, should be monitored for emissions and defects and those emissions and defects related normal wear and tear be repaired upon identification or within a short timeline (within 24 hours). The EPA solicits comment on the 24-hour timeline, acknowledging that 24 hours may be sufficient for some companies to make routine maintenance fixes such as tightening, cleaning, or lubricating equipment, this timeline might pose challenges for other companies. The EPA requests comment on all aspects this proposed timeline, including suggested alternative timelines and supporting rationales.
III.6b	Covers and Closed Vent Systems: The EPA is soliciting comment on all aspects of the proposed changes to the CVS requirements. The EPA is taking comment on whether these changes fully address concerns raised by petitioners regarding the CVS monitoring and repair requirements not recognizing the unique challenges the oil and gas industry, specifically, because of the fact that facilities have many remote sites where rapid repair may be significantly more challenging than facilities such as refineries or chemical plants that are staffed twenty four hours a day.
III.6c	Petitioners expressed concerns that the current NIE requirements create perverse incentives that discourage the use of advanced detection technologies or proactive voluntary monitoring. The Agency is also taking comment on the impacts that these proposed provisions may have on willingness to use alternative monitoring approaches.

III.6d	Covers and Closed Vent Systems: The EPA is soliciting comment on petitioners' suggestion that the NIE standard for CVSs should be replaced with an LDAR work practice approach more consistent with the framework applied to fugitive emissions components. EPA takes comment on petitioners' arguments that in many cases the components of a CVS (valves, pipes and connectors etc.) are identical to the components covered by the fugitive program.
III.6e	Covers and Closed Vent Systems: The EPA is soliciting comment on what specifically such an approach (similar to the LDAR work practice standard) might entail. In particular, the Agency is soliciting comment on whether an LDAR approach could be designed with additional safeguards to account for the fact that unlike other components of the existing LDAR program, CVS are integral to the ability to control any emissions that have been captured and are being routed to the control device through the CVS.
III.6f	Covers and Closed Vent Systems: The EPA is soliciting comment on the extent to which an inadequate or undersized tank design is the underlying cause of emissions from CVS on storage vessels and whether the proposed NIE requirements address the challenges the industry faces.
III.6g	Covers and Closed Vent Systems: The EPA is soliciting comment on whether there are better systematic approaches to identifying under-designed CVS than a requirement to operate CVS with NIE? The Agency is considering whether an inability to repair within 24 hours is an appropriate way to identify systems with design flaws, and what the appropriate criteria and requirements are to address chronic leakers under an NIE or another approach.
III.7a	Control Devices: Continuous burning pilot flame: The EPA solicits comment on the reliability, efficacy, and overall performance of automatic igniter pilot technology to ascertain if the devices perform comparably to continuously lit pilot flames. Moreover, the EPA solicits comment on the number of sites that have to use additional fuel (*i.e.*, not from their production streams) to sustain a continuous pilot flame. EPA also solicits comment on the emissions and costs associated with maintaining a continuous pilot light when no emissions from the unit are being sent to the flare (whether the fuel used for the pilot light is an additional fuel (such as propane) or from the sites production stream (*e.g.*, natural gas)).
III.7b	Control Devices: EPA Method 22 "as found" conditions: The EPA solicits comment on whether a 24-operating-hours grace period suffices to accommodate the potential situations raised by petitioners, particularly considering the frequency of intermittent venting or accessibility of some sites.
III.7c	Control Devices - Temporary control devices and backup control devices: The EPA solicits comment on the use of BCDs, specifically on how BCDs differ from the permanently installed control devices operating at a given facility. The EPA additionally requests information on the incidence of use and the number of BCDs across the industry and solicits comment on how to define BCDs so as to not inadvertently incentivize their use over permanently installed control devices.
III.7d	Control Devices: Temporary process controllers: The EPA invites comment on the incidence of standalone TPCs present during the construction phase of a well and what the alternate standard from the zero-emitting provisions in the March 2024 Final Rule for these devices should be, along with providing any supporting information that the EPA can consider regarding TPCs that are not utilized as part of a TCD configuration.
III.7e	Control Devices: Control device categories: The EPA is clarifying control device requirements by including seven definitions from NESHAP subpart CC for Petroleum Refineries in NSPS OOOOb. The EPA solicits comment on proposing to add these definitions to NSPS OOOOb (40 CFR 60.5430b) for clarity.
III.7f	Control Devices: OTM-52A: The EPA is soliciting comment on the practical use of a method based on OTM-52A for demonstrating compliance with the NSPS OOOOb stack testing requirements for enclosed combustion devices. Specifically, the EPA seeks feedback on field applicability, data

	quality, and implementation feasibility of using a combustion-efficiency-based method in lieu of traditional removal efficiency approaches. The EPA also requests general comments on the OTM-52A method, including but not limited to, test duration, procedures, and QA/QC. The Agency is also requesting comment on whether the provisions for alternative test methods in 40 CFR 60.5412b(d) would prevent the use of a combustion efficiency method, like OTM-52A, and whether different performance testing requirements should be considered for enclosed combustion devices that operate intermittently.
III.7g	Control Devices: OTM-52A: The EPA is taking comment on whether the EPA should specifically allow by rule the use of OTM-52A, at least until the Agency develops its own official version (*i.e.*, EPA Method "XX"). In addition to the broad question of whether OTM-52A (or a method based on OTM-52A) should be allowed, the EPA is taking comment on any specifics related to how the alternative could be incorporated, and whether it would require any other changes (such as an alternative compliance limit) to demonstrate any differences between a testing approach on removal efficiency vs combustion efficiency, and specifically what those changes should be.
III.8a	Equipment Leaks at Gas Plants: Low-e valve repair requirements: The EPA solicits low-E valve versus non-low-E valve cost information.
III.8b	Equipment Leaks at Gas Plants: Low-e valve repair requirements: The EPA proposes to amend the March 2024 Final Rule to allow owners and operators to conduct a "first attempt at repair" of a leaking valve as defined in 40 CFR 60.5430b and 60.5430c prior to being required to utilize a low-E valve or low-E packing to replace or repack a leaking valve. The EPA solicits comment on this proposed change.
III.8c	Equipment Leaks at Gas Plants: De minimis VOC or methane applicability threshold: The Agency requests specific information and monitoring data for processing equipment at natural gas plants that would support a 1 percent by weight equipment applicability methane concentration threshold.
III.8d	Equipment Leaks at Gas Plants: De minimis VOC or methane applicability threshold: The Agency is also requesting specific information and monitoring data for processing equipment at natural gas plants to support a 10 percent by weight equipment applicability VOC concentration threshold.
III.8e	Equipment Leaks at Gas Plants: De minimis VOC or methane applicability threshold: The Agency also solicits general comments on all aspects of EPA's proposed changes related to the de minimis VOC or methane applicability threshold.
III.8f	Equipment Leaks at Gas Plants: For purposes of setting monitoring requirements for equipment leaks at gas plants, the EPA seeks comment (including data and detailed information) on how often equipment leaks are found at gas plants, the approximate volume of gas emitted during a typical fugitive emissions event at a gas plant, estimates regarding the approximate length of time that equipment leak events lasts at gas plants, and the cost of conducting monitoring for equipment leaks (e.g., capital costs, variable costs, changes to business practices, safety implications of conducting the fugitives monitoring, and any other relevant costs).
III.8g	Equipment Leaks at Gas Plants. The EPA is soliciting comment on the cost effectiveness and cost reasonableness of the gas plant requirements generally. The EPA is specifically requesting information on the appropriate frequency, type of monitoring technology, and other relevant information that may improve the EPA's cost effectiveness and cost reasonableness analysis, allowing the EPA to better target emission reductions and the EPA also seeks comment on whether the gas plant requirements in the March 2024 Final Rule are necessary considering this information.
III.9a	Associated Gas from Wells Producing Primarily Oil: The EPA solicits comment and information on the proportion of owners and operators that also own or operate their own midstream sales line infrastructure.
III.9b	Associated Gas from Wells Producing Primarily Oil: The EPA is also seeking comment on an alternative approach which would maintain the current structure of the associated gas requirements (along with the BSER

	analysis from the March 2024 Final Rule) in both NSPS OOOOb and EG OOOOc while attempting to address the specific concerns raised by industry stakeholders through targeted regulatory amendments.
III.9c	Associated Gas from Wells Producing Primarily Oil: The EPA solicits comment on allowing an extension of the temporary flaring durations under 40 CFR 60.5377b(d)(3) and (4) and 40 CFR 60.5391c(c)(3) and (4) per incident; and the definition of a "temporary interruption incident" for 40 CFR 60.5377b(d)(3) and (4) as well as 40 CFR 60.5391c(c)(3) and (4). Specifically, whether the definition should include any additional examples of temporary interruption incidents described in previous rulemaking, such as, for example, gas gathering line or collection system capacity constraints, gas gathering line or collection system outages or maintenance, well surges exceeding gas gathering line or collection system capacity, and situations in which the gas gathering line or collection system will not accept the gas due to quality concerns (of the associated gas from the well or from other wells in the area).
III.9d	Associated Gas from Wells Producing Primarily Oil: In correspondence with the industry, owners and operators did not offer specific alternative durations needed to address these temporary interruption incidents. The EPA is requesting comment and supporting information regarding the typical durations of midstream service outages and what an appropriate and reasonable timeline would be for resolving gas quality issues.
III.9e	Associated Gas from Wells Producing Primarily Oil: The Agency is soliciting comment on whether an annual temporary flaring limit should be included and, if so, what a reasonable limit would be.
III.9f	Associated Gas from Wells Producing Primarily Oil: Notifications and periodic reports: The EPA is soliciting comment on whether it could require that an initial notification be submitted to the Agency as soon as an owner or operator becomes aware of a temporary interruption incident that results in the need to flare, and if so, what documentation could be required to explain why no other compliance method under NSPS OOOOb or EG OOOOc is possible for controlling the associated gas. The Agency also solicits comment on whether to require an owner or operator submit a notification to the EPA upon resolution of the temporary interruption incident, and similarly, whether during the incident, the EPA should require periodic reports on the status of the temporary interruption incident and the steps being taken to resolve it or whether such notifications and periodic reports documenting these incidents should be required to be maintained as records.
III.9g	Associated Gas from Wells Producing Primarily Oil - Annual and periodic reports: The EPA requests comment on whether the Agency should require that owners and operators include in annual reports information related to temporary interruption incidents (*i.e.*, when the temporary interruption incident started, circumstances related to the incident, and resolution status). The Agency is also soliciting comment on the appropriate frequency of periodic status reports related to the status of a temporary interruption incident, and whether commenters agree that EPA should require such reports.
III.9h	Associated Gas from Wells Producing Primarily Oil: The Agency is requesting comment on what constitutes an appropriate time frame for limiting routine flaring for new wells if it were to include a limit on the duration an owner or operator may flare during pipeline construction, *e.g.*, 3 years from the time the well begins operation. The Agency is requesting comment on what constitutes an appropriate time frame for limiting routine flaring for new wells under this scenario.
III.9i	Associated Gas from Wells Producing Primarily Oil: In instances where flaring of associated gas is necessary during pipeline construction, the EPA is soliciting comment on whether owners and operators should be required to submit in their initial annual report the details of the contractual arrangement, as well as the schedule that outlines when compliance will be achieved. In each subsequent annual report, the owner or operator could be

	required to submit an update on the status of the effort, along with a detailed explanation of any delays in schedule. The EPA is also specifically requesting comment on whether separate requirements should be included for these wells, or whether the considered requirement for annual technical infeasibility determinations and certifications would achieve the same objective of requiring compliance with 40 CFR 60.5377b(a) when the gas gathering line or collection system is able to accept the associated gas produced.
III.10a	Well Site Subcategorization: The EPA requests comment on the appropriate consideration of "energy requirements" and whether the energy impacts from not being able to produce oil and natural gas in the United States allows treating marginal and conventional wells differently.
III.10b	Well Site Subcategorization: Sweetening units: The Agency is requesting information on whether sweetening units are located at marginal well sites and whether different standards should be included in NSPS OOOOb for sweetening units located at marginal well sites.
III.10c	Well Site Subcategorization: Oil well associated gas: The EPA proposes to conclude that routing to an existing control device if one is available is not the best control option for associated gas. The EPA is requesting comment on these assumptions and whether routing to an existing control device should be considered a viable option for associated gas at marginal oil wells.
III.10d	Well Site Subcategorization: The EPA requests comment on the proposed weighting factors (see section III.K.i of this preamble) used in the BSER analysis.
III.10e	Well Site Subcategorization: The Agency is requesting comment on a subcategorization approach to marginal well sites that creates two subcategories of marginal well sites, where there would be different standards for well sites with average production levels of 6 boe per day or less and well sites with average production levels greater than 6 boe and less than or equal to15 boe per day. This subcategorization would likely result in more stringent standards for the higher producing subcategory (with higher profits) and less stringent standards for the lower emitting subcategory.
III.10f	Well Site Subcategorization: Although stakeholders suggested the aforementioned cut-off levels (highlighted in Question III.10e), the EPA is requesting comment on whether there are other reasonable ways to subcategorize based on production (*e.g*. would subcategories at other production levels be more appropriate) or whether further distinctions may be needed to appropriately target meaningful emissions reductions.
III.10g	Well Site Subcategorization: The EPA is soliciting comment on an alternative set of requirements if the Agency establishes two marginal well site subcategories. The EPA is specifically requesting comment on this set of compliance options for a dual subcategory for marginal well sites (see section III.K.1.l of this preamble).
III.10h	Well Site Subcategorization: In addition, for purposes of setting fugitive emissions monitoring requirements for marginal wells, the EPA seeks comment (including data and detailed information) on how often fugitive emissions are found at marginal well sites, the approximate volume of gas emitted during a typical fugitive emissions event at a marginal well site, estimates regarding the approximate length of time that fugitive events last at marginal well sites, and the cost of conducting fugitive emissions monitoring at a marginal well site (e.g., capital costs, variable costs, changes to business practices, safety implications of conducting the fugitives monitoring, and any other relevant costs).
III.10i	Well Site Subcategorization: The EPA is also soliciting comment on the cost effectiveness and cost reasonableness of the fugitive emissions monitoring requirements in this proposal for marginal wells. Specifically, the EPA is requesting information on the appropriate frequency, type of monitoring technology, equivalent monitoring technologies for various equipment types, and other relevant information that may improve EPA's cost effectiveness and cost reasonableness analysis, allowing the EPA to better target emission reductions. (Question III.10i) .

III.10j	Well Site Subcategorization: The Agency also seeks comment on whether the fugitive emissions monitoring requirements in NSPS OOOOb and EG OOOOc are necessary for marginal wells considering this information. (Question III.10k)
III.10k	Well Site Subcategorization: This proposal also includes proposed instances that constitute a modification to an existing marginal well site. The EPA is seeking comment on what level or type of stimulation for the purposes of increased production could result in increases in emissions.
III.10l	Well Site Subcategorization: The EPA is proposing the following definition. "*Conventional well site* means a well site with only conventional wells." The EPA is also proposing to add to the definition of "well site" the phrase "this term encompasses both unconventional and conventional well sites." The Agency requests comment on these definitions.
III.10m	Well Site Subcategorization: The EPA proposes to conclude that the subset of total oil and gas wells that are conventional is largely the same subset of wells that have production levels of 15 boe per day or less (*i.e.*, marginal wells). The Agency is requesting comment on the conclusion that the subset of wells that are marginal largely overlaps with the subset that are conventional wells.
III.10n	Well Site Subcategorization: The EPA is specifically requesting comment on the accuracy of our conclusion that most conventional wells are low production and likely have lower emissions than unconventional wells.
III.10o	Well Site Subcategorization: If commenters on this proposal do not agree with our conclusion that most conventional wells are low production wells that likely have lower emissions than unconventional wells, the EPA is requesting information on the prevalence of high production conventional wells that have emissions equivalent to, or higher than, unconventional wells.
III.10p	Well Site Subcategorization: The EPA is requesting comment on whether all unconventional wells should be subject to the more stringent standards even in instances where well production is low.
III.10q	Well Site Subcategorization: In addition, for purposes of setting fugitive emissions monitoring requirements for conventional wells, the EPA seeks comment (including data and detailed information) on how often fugitive emissions are found at conventional well sites, the approximate volume of gas emitted during a typical fugitive emissions event at a conventional well site, estimates regarding the approximate length of time that fugitive events last at conventional well sites, and the cost of conducting fugitive emissions monitoring at a conventional well site (e.g., capital costs, variable costs, changes to business practices, safety implications of conducting the fugitives monitoring, and any other relevant costs).
III.10r	Well Site Subcategorization: The EPA is also soliciting comment on the cost effectiveness and cost reasonableness of the fugitive emissions monitoring requirements in this proposal for conventional wells. Specifically, the EPA is requesting information on the appropriate frequency, type of monitoring technology, equivalent monitoring technologies for various equipment types, and other relevant information that may improve EPA's cost effectiveness and cost reasonableness analysis, allowing the EPA to better target emission reductions.
III.10s	Well Site Subcategorization: The Agency also seeks comment on whether the fugitive emissions monitoring requirements in NSPS OOOOb and EG OOOOc are necessary for conventional wells considering this information.
III.10t	Well Site Subcategorization: This proposal also includes proposed instances that constitute a modification to an existing conventional well site. EPA is seeking comment on what level or type of stimulation for the purposes of increased production could result in increases in emissions.
IV.1	Draft CEDRI NSPS OOOOb Template. A draft version of the proposed templates for these reports is included in the docket for this action. The EPA specifically requests comment on the content, layout, and overall design of the template(s).

IV.2	Draft CEDRI NSPS OOOOc Template. A draft version of the proposed templates for these reports is included in the docket for this action. The EPA specifically requests comment on the content, layout, and overall design of the template(s).
VI.1	The EPA requests comment on the modeling assumptions, data inputs, and methodological choices used in the accompanying RIA, including assumptions around site equipment assignment, annual operating costs, and production decline rates.

VIII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review

The Office of Information and Regulatory Affairs (OIRA) has determined that this action is a "significant regulatory action" as defined in Executive Order 12866, and has been reviewed by OIRA accordingly. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket for this action. See memorandum entitled *Regulatory Impact Analysis for 2026 NSPS & EG Reconsideration* for the EPA's regulatory impact analysis.

The EPA estimated present values (PV) and equivalent annualized values (EAV) of the estimated increase in economic surplus of this proposed reconsideration and co-proposal in 2024 dollars over the 2025 to 2050 period. Estimated increases in economic surplus include reductions in compliance cost expenditures from industry, as well as increased value to consumers from lower commodity prices and revenues to industry from increased production. Surplus changes also account for the forgone value of natural gas captured as a result of less stringent compliance obligations. Changes beyond compliance cost savings are represented by the Savings from Energy Market Impacts values. The aspects of the proposed reconsideration reflected in the quantitative analysis are the subcategorization and standard setting for marginal well sites and removal of route to sales as the BSER for associated gas. The aspects of the co-proposal reflected in

the quantitative analysis are the subcategorization and standard setting of conventional well sites and removal of route to sales as the BSER for associated gas.

Table 35 presents the estimated additional economic surplus of this proposed reconsideration and co-proposal in 2024 dollars for the baseline which includes the March 2024 Final Rule (*i.e.*, the primary baseline analyzed in the RIA). This table presents the PV and EAV of these estimates discounted at three percent and seven percent.

Table 35. Present Value and Equivalent Annualized Value of Increased Economic Surplus Estimates of the Proposed Action from 2025-2050 (Millions of 2024$)[a]

		3 Percent Discount Rate		7 Percent Discount Rate	
		PV	EAV	PV	EAV
Proposed Reconsideration	Compliance Cost Savings[b]	$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
Co-Proposal	Compliance Cost Savings[b]	$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

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] The Compliance Cost Savings rows include the change in value of product recovery.

The analysis, which is contained in the Regulatory Impact Analysis for this rulemaking, is consistent with Executive Order 12866 and is available in the docket for this action.

B. Executive Order 14192: Unleashing Prosperity Through Deregulation

This action is expected to be an Executive Order 14192 deregulatory action because the action is expected to result in cost savings.

C. Paperwork Reduction Act (PRA)

The Office of Management and Budget (OMB) previously approved the information collection activities for the March 2024 Final Rule under the PRA and has

assigned OMB control number 2060–0721. The approved information collection request (ICR) number is 2523.07. You can find a copy of the previously submitted ICR in Docket EPA-HQ-OAR-2021-0317.

The EPA has revised the approved ICR to reflect proposed recordkeeping and reporting requirement changes associated with the EPA's proposed amendments to rescind the Super Emitter Program; to subcategorize different types of well sites into marginal well sites and conventional well sites and the reduction of recordkeeping and reporting requirements for emission sources located at marginal well sites; and the proposed reduction of recordkeeping and reporting requirements related to liquids unloading, process controllers, pumps, fugitive emissions, storage vessels, covers and CVSs, equipment leaks at gas plants, and associated gas.

The information collection activities are necessary for the Administrator to confirm the compliance status of affected new and modified oil and natural gas facilities. These recordkeeping and reporting requirements are authorized by CAA section 114. All information submitted to the Agency for which a claim of confidentiality is made will be safeguarded according to the EPA regulations set forth in 40 CFR 2.201 et seq., Chapter 1, Part 2, Subpart B-Confidentiality of Business Information.

Respondents/affected entities: Oil and natural gas operators and owners.

Respondent's obligation to respond: Mandatory (per CAA §114)

Estimated number of respondents: 2,786

Frequency of response: Varies depending on affected facility.[451]

Total estimated burden: 609,516 hours (per year). Burden is defined at 5 CFR 1320.3(b).

[451] The specific frequency for each information collection activity within this request is shown in tables 1a through 1d of the Supporting Statement in the public docket.

Total estimated cost: $60,916,791 ($2024) (per year), includes $14,177,335 in annualized capital costs.

The total estimated burden represents a reduction of 274,109 hours (per year) and a reduction of 16,079,963 ($2024) compared to the existing collection for NSPS OOOOb. The proposed amendments are expected to result in only minimal changes to the ICR burden previously estimated for owners/operators under NSPS OOOOa and for states under EG OOOOc and overall, the burden and associated costs would remain largely the same.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the EPA's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the Agency using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at www.reginfo.gov/public/do/PRAMain. Find this particular information collection by selecting "Currently under Review - Open for Public Comments" or by using the search function. OMB must receive comments no later than [**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER**].

The revised ICR based on this proposed rule had been submitted for approval to the OMB under the PRA. The revised ICR document that the EPA prepared has been assigned EPA ICR number 2523.09. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action relieves regulatory burden on, and provides overall cost savings for, the small entities subject to the rule. This proposed reconsideration will lead to an estimated reduction in EAV costs over the 2027 to 2050 timeframe, discounted to 2025 and in 2024 dollars, of about $2.7 and $2.8 billion per year at three and seven percent discount rates, respectively; similarly the co-proposal is estimated to have a reduction in EAV costs, over the same timeframe, of about $2.3 and $2.4 billion per year at three and seven percent discount rates, respectively. Therefore, the EPA has concluded that this action will relieve regulatory burden for all directly regulated small entities.

For further details, see the document entitled *Regulatory Impact Analysis for 2026 NSPS & EG Reconsideration*, available in the docket for this rulemaking.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million (adjusted annually for inflation) or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any State, local or Tribal governments or the private sector. This action proposes changes to NSPS OOOO, OOOOa, and NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements and corrects and clarifies regulatory text.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the

States, or on the distribution of power and responsibilities among the various levels of government. However, the EPA recognizes that States will have a substantial interest in this action and any future revisions to associated requirements. This action proposes changes to NSPS OOOO, OOOOa, and NSPS OOOOb and the model rules within EG OOOOc based on some of the petitions for reconsideration received on the March 2024 Final Rule requirements and corrects and clarifies regulatory text.

G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action has Tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized Tribal governments, nor preempt Tribal law. Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA will engage in consultation with tribal officials during the development of this action

As described in the March 2024 Final Rule preamble, the EPA consulted with tribal officials consistent with the EPA Policy on Consultation with Indian Tribes early in the process of developing the March 2024 regulation to permit them to have meaningful and timely input into its development.[452] A summary of that consultation is provided in a memorandum to the docket for the March 2024 Final Rule.[453]

As part of the March 2024 Final Rule record, the EPA found that 112 distinct areas of Indian country are located within 50 miles of an affected oil and natural gas source, and 32 Tribes have one or more oil or natural gas sources on their Indian country lands.[454] While many of the affected and designated facilities impacted by final NSPS and EG in Indian country are owned by private entities, some Tribes also own affected and or designated facilities. The EPA explained there would be Tribal

[452] 89 FR 17028, 17029 (March 8, 2024).
[453] Document ID No. EPA-HQ-OAR-2021-0317-1510.
[454] 86 FR 63143 (November 15, 2021).

implications associated with the March 2024 rulemaking in the case where a unit is owned by a Tribal government or in the case of the NSPS, a Tribal government is given delegated authority to enforce the rulemaking. The EPA believes that this information is still accurate for this reconsideration proposal. Consistent with the EPA Policy on Consultation with Indian Tribes, the EPA will send letters to all 575 Federally recognized Tribes to offer consultation on this proposal.

As a reminder, Tribes are not required to develop plans to implement the EG under CAA section 111(d) for designated existing sources. The EPA notes a future final reconsideration rule does not directly impose specific requirements on designated facilities, including those located in Indian country. Before developing any standards for sources in Indian country, the EPA would consult with leaders from affected Tribes.

H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045 directs federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children.

This action proposes changes to NSPS OOOO, OOOOa, and NSPS OOOOb and the model rules within EG OOOOc based on some of the petitions for reconsideration received on the March 2024 Final Rule requirements and corrects and clarifies regulatory text. The EPA has determined that this action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk. Since this action does not concern human health effects, the EPA's Policy on Children's Health does not apply.

I. Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. Further, the EPA has concluded that this action is not likely to have any adverse energy effects because this action proposes changes to NSPS OOOO, OOOOa, and NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements and corrects and clarifies regulatory text. As a result of the proposed and co-proposed changes, which include deregulatory changes that would reduce burdens on and compliance difficulties experienced by the oil and natural gas industry, no adverse impacts are associated with this action. For more information, see Section 6 of the RIA.

J. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR part 51

This action does not involve any new technical standards.

Lee Zeldin,

Administrator.

[FR Doc. 2026-22082 Filed: 10/28/2026 8:45 am; Publication Date: 10/29/2026]