6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2024-0358; FRL-12031-02-OAR]

RIN 2060-AW35

Reconsideration of 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 (EPA).

ACTION: Final rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is finalizing amendments to the New Source Performance Standards (NSPS) and Emission Guidelines (EG) for Existing Sources for the Crude Oil and Natural Gas Source Category in response to petitions for reconsideration of the March 8, 2024, final rule. Specifically, this action finalizes discrete technical changes to two aspects of the rules. First, this action finalizes discrete technical changes to the temporary flaring provisions for associated gas in certain situations. Second, this action finalizes discrete technical changes to the vent gas net heating value (NHV) continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion device(s) (ECD). In a letter dated May 6, 2024, the EPA notified petitioners and the public that the Agency granted reconsideration on these two aspects of the final rule. These amendments

neither finalize changes to any other aspect of the March 8, 2024, final rule, nor finalize alterations to the substance of any emission standards within that final rule. This action also finalizes a technical correction to reinstate regulatory text for the reporting requirements in 40 CFR 60.5420b(b)(1) through (15), which were mistakenly deleted by the December 2025 Final Rule. Also, in this action, the EPA finalizes changes to the regulatory text to meet the Office of the Federal Register formatting and style requirements.

DATES: This final rule is effective on [**INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. The incorporation by reference of certain material listed in the rule is approved by the Director of the *Federal Register* as of **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER].**

ADDRESSES: The EPA has established a docket for this rulemaking under Docket ID No. EPA-HQ-OAR-2024-0358. All documents in the docket are listed on the *https*://*www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov/*.

FOR FURTHER INFORMATION CONTACT: For questions about this final rule, contact Amy Hambrick, Natural Resources Division (E143-05), Office of Clean Air Programs, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive P.O. Box 12055 RTP, North Carolina 27711; telephone number: (919) 541-0964; and email address: *hambrick.amy@epa.gov*. Additional questions may be directed to the following email address: *O&GMethaneRule@epa.gov*.

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. We use 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:

ALT	alternative
AGR	acid gas removal
APA	Administrative Procedure Act
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
AXPC	American Exploration and Production Council
BSER	best system of emission reduction
Btu/lb	British thermal units per pound
Btu/scf	British thermal units per standard cubic feet
°C	degrees Celsius
CAA	Clean Air Act
CBI	Confidential Business Information
CFR	Code of Federal Regulations
CO_2	carbon dioxide
CRA	Congressional Review Act
DRE	destruction removal efficiency
ECD	enclosed combustion device(s)
EG	emissions guidelines
EIA	U.S. Energy Information Administration
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FR	*Federal Register*
GC	gas chromatograph
GHG	greenhouse gas
HP	high-pressure
H_2S	hydrogen sulfide
ICR	information collection request
IFR	interim final rule

LP	low-pressure
MACT	maximum achievable control technology
MCF	thousand cubic feet
MS	mass spectrometer
NAICS	North American Industry Classification System
NHV	net heating value(s)
NHV_{cz}	combustion zone NHV
NHV_{dil}	NHV dilution parameter
NRU	nitrogen removal units
NSPS	new source performance standards
NTTAA	National Technology Transfer and Advancement Act
OGI	Optical Gas Imaging
OMB	Office of Management and Budget
PRA	Paperwork Reduction Act
RFA	Regulatory Flexibility Act
RLSO	redline strike out
RTC	Response to Comment
scf	standard cubic feet
TAR	Tribal Authority Rule
TCEQ	Texas Commission on Environmental Quality
TXOGA	Texas Oil and Gas Association
UMRA	Unfunded Mandates Reform Act
U.S.	United States
VISR	Video Imaging Spectro-Radiometry
VOC	volatile organic compound(s)

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

On March 8, 2024, the EPA published a final rule for the Crude Oil and Natural Gas source category under CAA section 111(b) and (d) at 89 FR 16820 ("March 2024 Final Rule"). The EPA finalized NSPS OOOOb for GHG and VOC emissions from new, modified, and reconstructed sources in this source category. The EPA also finalized EG OOOOc for GHG emissions from existing sources in this source category. The March 2024 Final Rule became effective on May 7, 2024. The March 2024 Final Rule applies to thousands of new sources and will apply to hundreds of thousands of existing sources when the EG is implemented 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; and natural gas production applicability includes processing, transmission, and storage, which includes the well and extends to, but does not include, the local distribution company custody transfer station.

After the publication of the March 2024 Final Rule, the EPA received multiple petitions[1] for reconsideration. On May 6, 2024, we notified certain petitioners and the public that we 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 NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices.[2]

On January 15, 2025, the EPA proposed amendments to the New Source Performance Standards and Emission Guidelines for Existing Sources for the Crude Oil and Natural Gas Source Category in response to these petitions for reconsideration ("January 2025 Proposal").[3] Specifically, we proposed discrete technical changes to two different aspects of the rules (*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). This action finalizes amendments to the March 2024 Final Rule resulting from our reconsideration of these two discrete issues.[4]

[1] See Docket No. EPA-HQ-OAR-2024-0358 for petitions for reconsideration received.
[2] See Docket No. EPA-HQ-OAR-2024-0358 for May 6, 2024, letter granting reconsideration.
[3] 90 FR 3734 (January 15, 2025).
[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.

On January 20, 2025, the President issued Executive Orders 14154 (Unleashing American Energy)[5] and 14156 (Declaring a National Energy Emergency).[6] Then, on January 31, 2025, the President issued Executive Order 14192 (Unleashing Prosperity through Deregulation).[7] On March 12, 2025, against this backdrop, the EPA announced plans for deregulatory actions to, among other things, unleash American energy.[8] On that same day, and as part of the larger Agency plan, the EPA announced plans to reconsider the regulations promulgated via the March 2024 Final Rule "to ensure they do not prevent America from unleashing energy dominance."[9]

On July 31, 2025, the EPA promulgated an IFR which extended deadlines for certain provisions related to control devices, equipment leaks, storage vessels, process controllers, and covers and closed vent systems in the NSPS OOOOb.[10] 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 the EG OOOOc. In December 2025, the EPA promulgated a final rule which responded to comments received on the July 2025 IFR and concluded that the regulatory amendments made in the IFR were still appropriate after consideration of comments.[11] In response to comments received, the December 2025 Final Rule also provided an additional 180-day extension (from the final rule's effective date) (until June 1, 2026) to the compliance dates related to NHV monitoring of flares and ECD found in 40 CFR 60.5417b(d)(8)(i) through (iv) and (vi), as well as 360

[5] 90 FR 8353 (January 29, 2025).
[6] 90 FR 8433 (January 29, 2025).
[7] 90 FR 9065 (February 6, 2025).
[8] *https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history*.
[9] *https://www.epa.gov/newsreleases/trump-epa-announces-oooo-bc-reconsideration-biden-harris-rules-strangling-american*.
[10] 90 FR 35966 (July 31, 2025).
[11] 90 FR 55671 (December 3, 2025).

days from the effective date of the December 2025 Final Rule (November 30, 2026) for owners or operators to submit initial annual reports pursuant to 40 CFR 60.5420(b).[12]

In this final rule, the EPA is finalizing changes to two aspects of the March 2024 Final Rule (*i.e.*, temporary flaring and NHV monitoring) after consideration of comments received on the January 2025 Proposal.

First, this action finalizes discrete technical changes to the temporary flaring provisions for associated gas in certain situations. These changes include:

- Extending the baseline time limit for temporary flaring of associated gas in certain situations from 24 hours to 72 hours with allowances to go beyond 72 hours in the event of exigent circumstances such as extreme inclement weather that prevent an owner or operator from safely accessing a well site to resolve an emergency or maintenance issue:
    - Requiring owners and operators to cease flaring as soon as the malfunction is resolved or the temporary flaring limit is reached, whichever occurs first, and
    - Clarifying recordkeeping and reporting requirements to include a written description of the exigent circumstance, steps taken to resolve the issue, date and time when it took place, and the total duration of flaring.

Second, this action finalizes discrete technical changes to the vent gas net heating value (NHV) continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and ECDs. These changes include:

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

- Revising numerous aspects of vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) options for flares and enclosed combustion devices by:
  - Expanding gas streams that are exempt from monitoring due to high NHV content to include all flare types (unassisted and assisted), as well as ECDs for both new and existing sources, and
  - Requiring NHV monitoring via continuous monitoring or alternative sampling demonstration in cases where inert gases are added, or for other miscellaneous scenarios which decrease the NHV content of the inlet gas stream for all flare types and ECDs for both new and existing sources.

2. Summary of the Major Provisions of this Regulatory Action

After considering comments received on the January 2025 Proposal, the EPA is allowing up to 72 hours for certain types of temporary flaring of associated gas based on information indicating that more than 24 or 48 hours is needed in some instances. While we acknowledge owners or operators have an economic incentive not to flare due to product (natural gas) loss that can equate to lost revenue, we have included a backstop requirement that owners or operators cease flaring after resolving the incident causing the need to flare. Collectively, the EPA is increasing the allowance of temporary flaring to 72 hours and including a backstop requirement, so owners or operators have both the economic incentive and a regulatory obligation to cease flaring of associated gas after an equipment malfunction or failure is addressed.

Additionally, the EPA solicited comments in the January 2025 Proposal on specific situations that would be considered “exigent circumstances.” Based on comments received and a re-assessment of data provided to the EPA, we are finalizing an allowance to flare for greater than 72 hours if an exigent circumstance persists and there is a need to extend the temporary flaring duration for maintenance, safety issues, or repairs. While we expect that the vast majority of temporary flaring situations to be addressed within the 72-hour timeframe, we recognize that there may be equipment malfunction incidents that require more than 72 hours to resolve due to circumstances beyond an owner's or operator's control. However, to ensure flaring does not continue beyond the time that is necessary to resolve a malfunction incident, we are including a backstop to this extended timeframe of flaring until such equipment malfunctions during these exigent circumstances are resolved or no longer present, whichever is sooner.

After considering input from commenters, the EPA is finalizing that an "exigent circumstance" must be a situation that restricts an owner's or operator's ability to reasonably access a site with the necessary equipment and personnel to address and resolve equipment malfunction incidents that cause the need to temporarily flare associated gas for more than 72 hours.

Lastly, the EPA is finalizing recordkeeping and reporting requirements when exigent circumstances are invoked. The EPA anticipates that exigent circumstances will be invoked only in limited cases, and that these additional recordkeeping and reporting requirements will not add undue burden to owners and operators.

The March 2024 Final Rule requires owners and operators to perform NHV sampling for flares and ECD through continuous monitoring of NHV or through periodic testing with sampling demonstrations. Industry petitioners submitted reconsideration petitions in response to the January 2025 proposal claiming that the compliance demonstrations are unnecessary, technically infeasible, and provide a limited timeline for compliance. The petitioners argued that over 99 percent of historical Btu stream data already complies with the prescribed minimum NHV content values (depending on flare type) outlined in the March 2024 Final Rule. Industry petitioners asserted that NHV content is usually a concern when inert gases are added to the process streams, which typically occurs during scheduled situations and is known to the operator of the affected source. The EPA made amendments to the NHV provisions based on data submitted by industry supporting their claims that the majority (over 99 percent) of facilities already complied with the minimum NHV requirements, and NHV content is only a concern when inert gases (and other miscellaneous scenarios) are added to the process streams.

Based on information from these petitions, as well as further information provided by industry following the January 2025 proposal, the EPA is finalizing changes to the continuous monitoring requirements and alternative performance test options (sampling demonstration) of NHV for flares and ECD. First, the EPA is expanding the gas streams that are exempt from monitoring due to high NHV content to include all flare and ECD for both new and existing sources. However, the EPA is also requiring that NHV monitoring be performed (via either continuous monitoring or the alternative performance test (sampling demonstration) option currently prescribed in the NSPS OOOOb and EG OOOOc regulations) in cases where inert gases are added and for other miscellaneous scenarios which decrease the NHV content of the inlet stream gas to all flare and ECD for both new and existing sources. In addition, the EPA is providing additional flexibility for alternative performance testing via the NHV grab sampling option by allowing samples to be taken upstream of the control device, provided that the sample is representative of the gas being introduced to the control device. Additionally, we are finalizing as proposed to allow breaks during weekends and holidays for the March 2024 Final Rule's consecutive 14-day sampling demonstration requirements to account for reasonable operational pauses provided no sampling is spaced more than 3 operating days apart from the previous sampling day. The EPA is also allowing less than one-hour sampling times in cases where low or intermittent flow makes it infeasible for both NSPS OOOOb and EG OOOOC sources, provided the sampling time used and reason for the reduced sampling time is documented and reported. Finally, the EPA is clarifying NHV testing must be reported in volumetric units (Btu/scf) instead of specific units (Btu/lb) in order to facilitate consistency in reporting.

This action also finalizes a technical correction to reinstate regulatory text for the reporting requirements in 40 CFR 60.5420b(b)(1) through (15), which were mistakenly deleted by the December 2025 Final Rule [13], under the authority of section 553(b)(B) of the Administrative Procedure Act, 5 U.S.C. 553(b)(B), which states, when an agency for good cause finds that public notice and comment procedures are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. Lastly, in this action, the EPA is finalizing formatting changes to the regulatory text to meet the required formatting standards of the Office of the *Federal Register*.[14]

3. Costs and Benefits

[13] 90 FR 55671 (December 3, 2025).

[14] To view the final formatting changes, see the full redline strike out (RLSO) of the regulatory text located in the public docket at EPA-HQ-OAR-2024-0358.

The EPA estimated present values (PV) and equivalent annualized values (EAV) of the estimated cost savings of this final reconsideration in 2024 dollars over the 2024 to 2038 period. The cost savings are represented in this analysis as the reduction in the number of affected sources and a reduction in the number of tests required for each affected source for the changes finalized in this reconsideration. In simple terms, these cost savings are an estimate of the decreased industry expenditures resulting from the final changes to the March 2024 Final Rule requirements. Under this final action, emissions changes and benefits from emission changes were not quantified. Qualitatively, the changes to the temporary flaring limitation could result in increases to emissions, while we do not expect any emissions changes to result from the changes to the NHV testing compliance demonstration.

Table 1 presents the estimated cost savings 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 EIA). This table presents the PV and EAV of these estimates discounted at three percent and seven percent.

Table 1–Present Value and Equivalent Annualized Value of Compliance Cost Savings Estimates of the Final Action from 2024-2038 (Millions of 2024$)

	3 Percent Discount Rate	**7 Percent Discount Rate**
Present Value	2,480	1,900
Equivalent Annualized Value	208	209

B. Does this action apply to me?

The source category that is the subject of this final action is the Crude Oil and Natural Gas Source Category regulated under Clean Air Act (CAA) section 111 through New Source Performance Standards (NSPS) and Emission Guidelines (EG). The 2022

North American Industry Classification System (NAICS) codes for the source category are summarized in Table 2. The NAICS codes serve as a guide for readers outlining the entities that this final action is likely to affect. 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 1, 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 this action. Other types of entities not listed in the table could also be affected by this action. To determine whether your entity is affected by this action, you should carefully examine the applicability criteria found in NSPS OOOOb and EG OOOOc. If you have questions regarding the applicability of this action 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 OOOOb, or your EPA Regional Office.

The issuance of the CAA section 111(d) EG in March of 2024 did not impose binding requirements directly on existing sources. The EG codified in 40 CFR part 60, subpart OOOOc, apply to States in the development, submittal, and implementation of State plans to establish performance standards to reduce emissions of greenhouse gas (GHG) in the form of limitations on methane from designated facilities that commence construction, modification, or reconstruction on or before December 6, 2022. Under the Tribal Authority Rule (TAR), eligible Tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a State. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment as a State for purposes of developing a Tribal Implementation Plan (TIP) implementing the EG codified in 40 CFR part 60, subpart OOOOc. The TAR 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 authority from the EPA to establish a TIP, the EPA has authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country.[15] A Federal plan would apply to all designated facilities located in the areas of Indian country unless the EPA approves a TIP applicable to those facilities.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the Internet. A brief summary of this final rule is available at *https://www.regulations.gov*, Docket ID No. EPA-HQ-OAR-2024-0358. Following signature by the EPA Administrator, the EPA will post a copy of this final action at

[15] 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.

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations. Following publication in the *Federal Register*, the EPA will post the *Federal Register* version of the final rule and key technical documents at this same website.

A memorandum showing the edits to 40 CFR part 60 subpart OOOOb and 40 CFR part 60 subpart OOOOc finalized in this action is available in the docket for this action (Docket ID No. EPA-HQ-OAR-2024-0358). Following signature by the EPA Administrator, the EPA also will post a copy of this document to *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations*.

II. Statutory Background and Regulatory History

A. CAA sections 111(b) and 111(d)

The EPA's authority for this rulemaking is CAA section 111, 42 U.S.C. 7411, which governs the establishment of standards of performance for stationary sources. This CAA section requires the EPA to list source categories to be regulated, establish standards of performance for air pollutants emitted by new sources in that source category, and promulgate EG for States to establish standards of performance for certain pollutants emitted by existing sources in that source category. For more information on the statutory background of CAA sections 111(b) and 111(d), and general implementing regulations, refer to the discussion provided in section IV.A (Statutory Background of the CAA sections 111(b), 111(d), and General Implementing Regulations) of the March 2024 final rule preamble. (89 FR 16846-16848; March 8, 2024).

B. What is the regulatory history and background of NSPS and EG for the Crude Oil and Natural Gas Source Category?

On November 15, 2021, the EPA published a "proposed rule" ("November 2021 Action") to reduce GHG and volatile organic compound (VOC) emissions from the oil and natural gas industry, specifically the Crude Oil and Natural Gas source category, but did not provide proposed regulatory text. In the November 2021 Action, the EPA discussed new standards of performance under CAA section 111(b) for GHG and VOC emissions from new, modified, and reconstructed sources in this source category, as well as changes to standards of performance already codified at 40 CFR part 60, subparts OOOO and OOOOa. The EPA also proposed EG under CAA section 111(d) for GHG emissions from existing sources in this source category for the first time. The EPA also discussed a protocol under the NSPS general provisions for optical gas imaging (OGI).

On December 6, 2022, the EPA published a supplemental proposed rule ("December 2022 Supplemental Proposal") that addressed two additional issues. First, the EPA proposed to update and expand the NSPS OOOOb standards in the November 2021 Action for GHG and VOC emissions from new, modified, and reconstructed sources. Second, the EPA proposed to update and expand the EG OOOOc standards in the November 2021 Action for GHG emissions from existing sources. For purposes of EG OOOOc, the EPA also proposed implementation requirements for State plans.

On March 8, 2024, the EPA published a final rule for the Crude Oil and Natural Gas source category under CAA section 111(b) and (d) at 89 FR 16820 ("March 2024 Final Rule"). The EPA finalized NSPS OOOOb for GHG and VOC emissions from new, modified, and reconstructed sources in this source category. The EPA also finalized EG

OOOOc for GHG emissions from existing sources in this source category. The March 2024 Final Rule became effective on May 7, 2024. The March 2024 Final Rule applies to thousands of new sources and will apply to hundreds of thousands of existing sources when the EG is implemented 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; and natural gas production applicability includes processing, transmission, and storage, which includes the well and extends to, but does not include, the local distribution company custody transfer station.

After the publication of the March 2024 Final Rule, the EPA identified, through its own internal reassessment, 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). The EPA published an IFR[16] which made minor and non-substantive corrections to the identified inadvertent errors in the March 2024 Final Rule.

Further, after the publication of the March 2024 Final Rule, the EPA received multiple petitions[17] for reconsideration. On May 6, 2024, we notified certain petitioners and the public that we granted reconsideration on two discrete aspects of the March 2024

[16] 89 FR 62872 (August 1, 2024); Document ID No. EPA-HQ-OAR-2021-0317-4057.
[17] See Docket No. EPA-HQ-OAR-2024-0358 for petitions for reconsideration received.

Final Rule: the temporary flaring provisions for associated gas in certain situations; and the vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices.[18] The American Petroleum Institute (API) and the AXPC,[19,20] the TXOGA,[21] the GPA Midstream,[22] and the Environmental Integrity Project[23] submitted petitions for reconsideration on those issues. This action finalizes amendments to the March 2024 Final Rule resulting from our reconsideration of these two discrete issues.[24]

On January 20, 2025, the President issued Executive Orders 14154 (Unleashing American Energy)[25] and 14156 (Declaring a National Energy Emergency).[26] Then, on January 31, 2025, the President issued Executive Order 14192 (Unleashing Prosperity through Deregulation).[27] On March 12, 2025, against this backdrop, the EPA announced

[18] See Docket No. EPA-HQ-OAR-2024-0358 for May 6, 2024, letter granting reconsideration.
[19] Letter to Michael S. Regan, EPA Administrator, from API and AXPC. Re: Provisions in the EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review." Reconsideration of the Final Rule. April 5, 2024. Hereinafter referred to as the "April 2024 API and AXPC petition."
[20] Letter to Michael S. Regan, EPA Administrator, from API and AXPC. 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. Hereinafter referred to as the "May 2024 API and AXPC petition."
[21] 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 7, 2024. Hereinafter referred to as the "May 2024 TXOGA petition."
[22] Letter to Michael S. Regan, EPA Administrator; Gautam Srinivasan, Associate General Counsel, EPA; and Amy Hambrick, SPPD, EPA; from GPA Midstream Association. GPA Midstream Association 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. Hereinafter referred to as the "May 2024 GPA Midstream petition."
[23] Letter to Michael S. Regan, EPA Administrator, from Air Alliance Houston; Clean Air Council; and Environmental Integrity Project. 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 (March 8, 2024), Docket No. EPA-HQ-OAR-2021-0317. May 7, 2024. Hereinafter referred to as the "May 2024 EIP et al. petition."
[24] 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.
[25] 90 FR 8353 (January 29, 2025).
[26] 90 FR 8433 (January 29, 2025).
[27] 90 FR 9065 (February 6, 2025).

plans for deregulatory actions to, among other things, unleash American energy.[28] On that same day, and as part of the larger Agency plan, the EPA announced plans to reconsider the regulations promulgated via the March 2024 Final Rule "to ensure they do not prevent America from unleashing energy dominance."[29]

On July 31, 2025, the EPA promulgated an IFR which extended deadlines for certain provisions related to control devices, equipment leaks, storage vessels, process controllers, and covers and closed vent systems in the NSPS OOOOb.[30] 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 the EG OOOOc. In December 2025, the EPA promulgated a final rule which responded to comments received on the July 2025 IFR and concluded that the regulatory amendments made in the IFR were still appropriate after consideration of comments.[31] In response to comments received, the December 2025 Final Rule also provided an additional 180-day extension (from the final rule's effective date) (until June 1, 2026) to the compliance dates related to NHV monitoring of flares and ECD 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 or operators to submit initial annual reports pursuant to 40 CFR 60.5420(b).[32]

C. Judicial Review and Administrative Review

Under CAA section 307(b)(1), judicial review of this final rulemaking is available only by filing a petition for review in the United States Court of Appeals for the District

[28] *https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history*.
[29] *https://www.epa.gov/newsreleases/trump-epa-announces-oooo-bc-reconsideration-biden-harris-rules-strangling-american*.
[30] 90 FR 35966 (July 31, 2025).
[31] 90 FR 55671 (December 3, 2025).
[32] See 90 FR at 35970-35972 (July 31, 2025), and 90 FR 55675-55676 (December 3, 2025) for discussion of the rationale for NHV monitoring extension.

of Columbia Circuit by [**INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER***]. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements. 42 U.S.C. 7607(b)(1)-(2).

CAA section 307(d)(7)(B) further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for the EPA to convene a proceeding for reconsideration "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment, (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." 42 U.S.C. 7607(d)(7)(B). Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC South Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

III. Summary of Final Amendments to NSPS OOOOb and EG OOOOc

The amendments in this final action relate to two 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 and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices. The two issues addressed in this final rule are separate and distinct from each other. Each of these two issues concern different portions of the March 2024 Final Rule that do not rely on the other. This action also finalizes a technical correction to reinstate regulatory text for the reporting requirements in 40 CFR 60.5420b(b)(1) through (15), which were mistakenly deleted by the December 2025 Final Rule.[33] Also, in this action, the EPA is finalizing formatting changes to the regulatory text to meet the required formatting standards of the Office of the *Federal Register*.[34]

Each regulatory change included in this final action is severable from the other. First, each of the two groups of substantive provisions amended in this action (temporary flaring of associated gas and vent gas NHV) is functionally independent from the other—*i.e.*, may operate in practice independently of the other requirements being amended here, such that the amendment of one set of requirements does not turn on the amendment of any other set of requirements. Put another way, the amendments to the temporary flaring provisions in no way impact or depend on the separate amendments to the NHV provisions. The same is true in the opposite direction. The amendments to the NHV provisions in no way impact or depend on the separate amendments to the temporary

[33] 90 FR 55671 (December 3, 2025).
[34] To view the final formatting changes, see the full redline strike out (RLSO) of the regulatory text located in the public docket at EPA-HQ-OAR-2024-0358.

flaring provisions. Second, as explained in this final rule preamble and the preamble to the proposed rule, the reasoning for each regulatory change is distinct and independent from the others. For example, amendments to the NHV provisions are separately justified from the amendments made to the temporary flaring of associated gas provisions. Again, the same is true in the opposite direction. Amendments to the temporary flaring of associated gas provisions are separately justified from the amendments made to the NHV provisions. Likewise, the formatting changes are also separate, distinct, and severable.

A. Temporary flaring provisions for associated gas in certain situations

Section XI.F.2 of the March 2024 Final Rule preamble presents a discussion of reasons why an owner or operator would need to flare or vent associated gas. Based on the reasons set out in that preamble, the EPA in the March 2024 Final Rule allowed owners and operators to temporarily route associated gas to a flare or control device for 24 hours in certain situations, including during a deviation caused by a malfunction (including for reasons of safety) and during repair, maintenance such as blowdowns, a bradenhead test, a packer leakage test, a production test, or commissioning. On January 15, 2025, the EPA proposed extending the allowable time for these situations from 24 hours to 48 hours ("January 2025 Proposal").[35] The EPA proposed the extended temporary flaring limit based in part on data provided by API, which showed that 85 percent of flaring events ended within 46 hours for activities such as maintenance, addressing safety issues, and repairs.

As discussed in section III.A.2 of the preamble to the January 2025 Proposal, industry petitioners indicated that the 24-hour limitation for temporary routing of

[35] 90 FR 3734 (January 15, 2025).

associated gas to a flare or control device in the March 2024 Final Rule is not sufficient in situations where a malfunction or an unintended incident endangers the safety of operator personnel and the public; as well as during repairs, maintenance (including blow downs), production tests, and commissioning. Petitioners claimed that a 72-hour timeframe for temporarily routing associated gas to a flare or control device for these situations is more appropriate due to the unique characteristics of some well sites (*e.g.*, due to the differing location and composition/amount of gas produced by wells), weather conditions, or a combination of both.

After consideration of comments received on the January 2025 Proposal and revisiting the data API provided to the Agency, the EPA is finalizing two primary changes to the January 2025 Proposal related to the temporary flaring of associated gas. First, the EPA finds that increasing the temporary flaring provisions up to 72 hours is appropriate. This extended timeframe gives owners and operators enough time to travel to facilities (including geographically remote facilities), troubleshoot, obtain necessary equipment, and complete repairs. It also provides sufficient time to overcome many inclement weather situations where access to a site may be temporarily limited. Further, moving to 72 hours will reduce the number of incidents where invoking exigent circumstances is necessary, thus reducing burden on the industry. Lastly, the extended timeframe also reduces the need to shut-in operations (where a well is temporarily closed off to restrict oil and gas flow and production due to unusual or unsafe conditions) in situations where the issue(s) cannot be addressed within 24 or 48 hours. Shutting-in operations can often result in the depressurization of equipment, which may lead to the venting of associated gas to the atmosphere without control. The venting of associated gas in these scenarios may exceed the emissions that would have otherwise occurred if the provisions allowed for an additional 24 hours of flaring thereby defeating the environmental objectives of the rule.[36]

Second, and relatedly, the EPA is requiring owners and operators to stop temporary flaring when repairs or maintenance are completed to avoid flaring longer than necessary during an individual incident. If repair or maintenance is completed within 72 hours, then flaring must stop at the time of completion. In other words, temporary flaring must cease as early as practicable and within 72 hours unless the facility properly invokes the procedures for a longer duration. While the 72 hours is a default maximum duration, if a situation arises that requires an owner or operator to temporarily flare beyond those 72 hours, then the final rule's additional provisions on exigent circumstances may apply. See section IV.A.1 of this preamble for further discussion of exigent circumstances. Also see section IV.A.2 for further discussion on temporary flaring beyond 72 hours.

By finalizing an upper limit of temporary flaring up to 72 hours, the final rule gives operators room to continue to develop ways to manage delays tied to these malfunctions and failures. At the same time, it prevents unnecessary flaring when problems are already fixed, thereby protecting against unnecessary emissions. This balance encourages owners and operators to keep improving how they detect and fix problems while providing flexibility and relief. It also supports better planning, faster repairs, and the potential for greater emission reductions in the future.

In summary, the EPA is allowing up to 72 hours for certain types of temporary flaring of associated gas based on information indicating that more than 24 or 48 hours is

[36] See 89 FR 16843-44 (March 8, 2024), section III.B.2.

needed in some instances. While we acknowledge owners or operators have an economic incentive not to flare due to product (natural gas) loss that can equate to lost revenue, we have included a backstop requirement that owners or operators cease flaring after resolving the incident causing the need to flare. Collectively, the EPA is increasing the allowance of temporary flaring to 72 hours and including a backstop requirement, so owners or operators have both the economic incentive and a regulatory obligation to cease flaring of associated gas after an equipment malfunction or failure is addressed.

Petitioners raised inclement weather as a circumstance that may deter an owner or operator from accessing an affected facility site and as a primary cause for the need to temporarily flare (*e.g.*, frozen gas lines, power outages). While the API dataset classifies inclement weather as the cause of 86 flaring events, the dataset classifies the primary cause of over 600 flaring events as "[u]nknown" and these events exhibited the highest average flaring durations and standard deviations. While we do not know the exact cause of the over 600 "unknown" flaring events in API's data set, maintaining a 24-hour flaring timeframe as promulgated in the March 2024 Final Rule based on the percentage of reported inclement weather-impacted events only presents a narrow reading of the data and does not reflect the unknown flaring events that exhibited the highest flaring durations and standard deviations. The EPA recognizes that the API data show that many temporary flaring events are resolved within 24 hours, and even more within 48 hours. Specifically, 83 percent of the instances were resolved within 24 hours and 85 percent within 48 hours. The EPA considered establishing cutoffs at 24 hours or 48 hours. However, the data indicate that 15 percent of instances could not be resolved within 48 hours. Industry noted that weather is a factor, but not the only factor, impacting temporary flaring events longer than 24 hours, and geographically dispersed sites, such as the Willison Basin which contained the majority (78%) of the > 24 hour flaring events, add additional challenge when responding to flaring events. Other causes of temporary flaring include non-scheduled maintenance or malfunction, planned maintenance, repair, or tests, and other issues such as weather or power outages. We determined based on the data and comments received on the proposal that establishing a cutoff at 24 hours or 48 hours is not supported because it necessarily fails to include a portion of the industry that is meaningful in this context. As such, we are finalizing an allowance to flare up to 72 hours for most situations, and are providing a mechanism to go beyond 72 hours to allow owners and operators the time they need to resolve equipment malfunction incidents and to include a backstop measure to ensure that temporary flaring does not continue after a malfunction incident is resolved.

In section III.A.3 of the January 2025 Proposal, the EPA acknowledged that rare instances may occur in which an owner or operator encounters a malfunction, safety, repair, or maintenance event that requires routing to a flare or control device beyond the proposed 48-hour duration. To address such instances, the EPA solicited comments on specific situations that would be considered “exigent circumstances.” Based on comments received and a re-assessment of data provided to the EPA, we are finalizing an allowance to flare for greater than 72 hours if an exigent circumstance persists and there is a need to extend the temporary flaring duration for maintenance, safety issues, or repairs. While we expect that the vast majority of temporary flaring situations to be addressed within the 72-hour timeframe, we recognize that there may be equipment malfunction incidents that require more than 72 hours to resolve due to circumstances beyond an owner’s or operator’s control. However, to ensure flaring does not continue beyond the time that is necessary to resolve a malfunction incident, we are including a backstop to this extended timeframe of flaring until such equipment malfunctions during these exigent circumstances are resolved or no longer present, whichever is sooner.

After considering input from commenters, the EPA is finalizing that an "exigent circumstance” must be a situation that restricts an owner’s or operator’s ability to reasonably access a site with the necessary equipment and personnel to address and resolve equipment malfunction incidents that cause the need to temporarily flare associated gas for more than 72 hours. Reasonable site access is the ability of an owner or operator to safely transport the necessary personnel and equipment to a site experiencing an incident. Examples of possible situations that could limit site access include, but are not limited to, road washout from flooding; roads obstructed by snow, debris, or trees; and unsafe travel conditions from extreme weather, wildfires, and hazmat emergencies. Impediments to resolving equipment malfunctions also include when an owner or operator is unable to secure the required equipment to resolve an equipment malfunction incident due to reasons beyond an owner's or operator’s control (*i.e.*, supply chain issues), or where there is a temporary shortage of personnel due to reasons beyond an owner's or operator's control (*e.g.*, a national pandemic). Examples of possible situations that could limit an owner's or operator's ability to secure required equipment to resolve an unexpected malfunction due to reasons beyond an owner's or operator's control include equipment transportation disruptions, trade disputes, equipment demand competition or national supply chain issues that cause major delays in securing parts or even render them unavailable for extended periods of time.

Not all situations that result in the need for temporary flaring qualify as exigent circumstances. Put another way, not all situations that result in the need to temporary flare will qualify as exigent circumstances. For example, inclement weather that results in equipment failures at a site, such as gas line freezing and power outages, would generally not constitute an exigent circumstance weather event if access to the site is not disrupted and equipment and personnel to resolve equipment malfunctions or failures are available.

Once the site is accessible and necessary equipment and personnel are available to resolve an equipment malfunction, flaring can continue until the malfunction is resolved. However, this must be no longer than 72 hours after the site is accessible, and the necessary equipment and personnel are available to resolve an equipment malfunction. The exigent circumstances provisions in the final rule are intended to accommodate rare instances where an owner or operator needs more than 72 hours to return the site to normal operations due to legitimate unforeseen circumstances outside of their control. The EPA does not expect that owners and operators will utilize these provisions often, and these provisions are not intended to allow for indefinite or long-term flaring. As always, the EPA may bring an enforcement action against an owner or operator whose actions do not comport with applicable regulatory provisions.

Lastly, the EPA is finalizing recordkeeping and reporting requirements when exigent circumstances are invoked. The EPA anticipates that exigent circumstances will be invoked only in limited cases, and that these additional recordkeeping and reporting requirements will not add undue burden to owners and operators. If an owner or operator claims that an exigent circumstance occurred and utilizes the extended temporary flaring timeframe, the owner or operator must maintain records that include: a written description of the "exigent circumstance" requiring the need to flare or route to a control device beyond 72 hours; a description of steps taken to resolve the need for temporary flaring/routing to a control device; the dates and times an identified "exigent circumstance" started and ended (*e.g.*, when owners or operators are able to access site, when personnel and/or equipment are available) and the total duration of each "exigent circumstance"; and the dates and times temporary flaring/routing to a control device started and ended and the total duration of temporary flaring/routing to a control device due to the identified “exigent circumstance.” We require owners and operators to report this information in their annual report. Owners and operators are already required to complete recordkeeping and reporting for temporary flaring events and the additional recordkeeping and reporting requirements that would result from the extension of flaring duration beyond the temporary flaring limit for exigent circumstances should not impose any additional undue burden on the industry.

B. Vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices

The EPA finalized compliance requirements for continuous monitoring and initial and periodic performance testing for flares and enclosed combustion device(s) (ECDs) in the March 2024 Final Rule. Of relevance here are the requirements for those two control devices regarding the NHV monitoring requirements and alternative performance test (sampling demonstration) option. In the March 2024 Final Rule, with exceptions for catalytic vapor incinerators, boilers and process heaters, and enclosed combustors where temperature is an indicator of destruction efficiency, all flares and ECD must maintain the NHV of the gas sent to it above a minimum NHV if the control device is pressure-assisted or uses no assist gas.[37,38] If an owner or operator uses a steam- or air-assisted flare or flare, the owner or operator must maintain the combustion zone NHV (NHV_{cz}) above a minimum level. If the owner or operator uses a perimeter assist air ECD or flare, the owner or operator must maintain the NHV dilution parameter (NHV_{dil}) above a minimum level. The NHV_{cz} and NHV_{dil} parameter terms account for the reduction in heating value caused by the introduction of air and/or steam. These terms were intended to ensure that the assist gas does not overwhelm the heating value provided by the vent gas to the point where proper combustion does not occur. Owners or operators also have the option to apply an alternative test method that either demonstrates continuous compliance with the combustion efficiency limit or directly demonstrates continuous compliance with the NHV_{cz} operating limit and, if applicable, the NHV_{dil} operating limit.

Associated gas from a well site affected facility was exempt from NHV monitoring (*i.e.*, assumed to always have high NHV) under the March 2024 Final Rule. Also under the March 2024 Final Rule, for each flare and ECD used to control gases other than associated gas from a well site affected facility, the owner or operator must conduct continuous monitoring using a calorimeter, gas chromatograph (GC), or mass spectrometer (MS) in order to determine the NHV of the vent stream.[39] As an alternative

[37] NHV is the potential energy available in a fuel sample, which is an indicator of flare performance and combustion efficiency. More specifically, it is the total energy released when a substance undergoes complete combustion with oxygen under standard conditions (*i.e.*, the amount of heat released when gas is burned). See *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/frequently-asked-questions-control-devices#nhv.*

[38] In NSPS OOOOb and EG OOOOc, NHV is typically expressed in units of Btus per standard cubic feet (scf). In the March 2024 Final Rule, NHV monitoring is used to determine the Btu content of a gas stream which indicates whether a control device (*i.e.*, a flare or an ECD) is reaching the required efficiency by combusting at least 95 percent of the pollutants of concern (*i.e.*, methane and/or VOC). The March 2024 Final Rule requires that an NHV value must be at or above a certain Btu/scf threshold, depending on the design of the flare or ECD. An NHV value below the prescribed applicable minimum NHV value can be an indicator of reduced control device performance and efficiency at less than an acceptable level.

[39] 89 FR 16820 (March 8, 2024).

to continuous monitoring of NHV, the March 2024 Final Rule allows the owner or operator to conduct a performance test to demonstrate the NHV of the vent stream that consistently exceeds the applicable NHV operating limit in one of two ways: continuous sampling for 14 consecutive days plus ongoing (three samples every five years), or manual sampling (twice daily for 14 consecutive days) plus ongoing (three samples every five years) sampling.[40] The March 2024 Final Rule requires a minimum collection time of at least one hour for each individual manually collected sample. If inlet gas flow is intermittent such that collecting 28 samples in 14 days is infeasible, an owner or operator must continue to collect samples beyond 14 days in order to collect a minimum of 28 samples.

Owners or operators also have the option to use an alternative test method that demonstrates continuous compliance with the combustion efficiency limit.[41,42] If there are no values of the combustion efficiency measured by the alternative test method over the 14-day period that are less than 95 percent, the gas stream is considered to consistently exceed the applicable NHV operating limit and the owner or operator is not required to

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[40] See 40 CFR 60.5417b(d)(8)(iii)(A) and 40 CFR 60.5417b(d)(8)(iii)(G) for NSPS OOOOb sources and 40 CFR 60.5417c(d)(8)(iii)(A) and 40 CFR 60.5417c(d)(8)(iii)(G) for EG OOOOc sources.

[41] Under the provisions outlined in 40 CFR 60.5412b(d) and 60.5415b(f)(1)(xi), sources can request to use an "equivalent method" pursuant to 40 CFR 60.8(b)(2), or "an alternative method the results of which [the Administrator] has determined to be adequate for indicating whether a specific source is in compliance" pursuant to 40 CFR 60.8(b)(3). The EPA is currently accepting and reviewing applications for alternative (ALT) test methods for NHV monitoring in the oil and natural gas sector. See *https://www.epa.gov/emc/oil-and-gas-alternative-test-methods#:~:text=The%20application%20portal%20can%20be,Air%20Emission%20Measurement%20Center%20webpage.* Since the March 2024 Final Rule's publication, two alternative test method requests have been approved by the EPA for use under NSPS subpart OOOOb: (1) ALT-156 Alternative Test Method to monitor the NHV of the flare combustion zone at facilities subject to NSPS OOOOb and (2) ALT-157 Alternative Test Method for determining NHV from gas sent to an ECD or Flare subject to NSPS OOOOb. A list of the EPA's approved alternative test methods can be found at *https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*.

[42] Per 40 CFR 60.8(b)(5), the EPA has more general authority to approve alternative test methods involving "shorter sampling times and smaller sample volumes when necessitated by process variables or other factors."

continuously monitor or conduct sampling of the NHV of the inlet gas to the flare or ECD.[43] Under the March 2024 Final Rule, owners or operators of steam- and air-assisted flares and ECD also must monitor the vent gas and assist gas flow rates and calculate NHV_{cz} and NHV_{dil} in accordance with the provisions in 40 CFR 63.670 (*i.e.*, the refinery maximum achievable control technology (MACT) rule, or "Refinery MACT" as codified in 40 CFR 63, National Emission Standards for Hazardous Air Pollutants (NESHAP) subpart CC). Alternatively, owners or operators of air-assisted flares may provide a one-time demonstration based on maximum air assist rates, minimum waste gas flow rates (based on backpressure regulator setting), and minimum NHV from the most recent sampling rather than continuously monitor vent gas and assist gas flow rates.[44]

In this Final Rule, the EPA is revising numerous aspects of the NHV monitoring and testing provisions in the March 2024 Final Rule. The EPA presented the rationale for these revisions in section III.B of the preamble of the January 2025 Proposal, with additional details provided in section IV.B of this preamble.

The EPA is expanding the gas streams that are exempt from monitoring due to high NHV content to include all flare and ECD for both new and existing sources. However, the EPA is also requiring that NHV monitoring be performed (via either continuous monitoring or the alternative performance test (sampling demonstration) option currently prescribed in the NSPS OOOOb and EG OOOOc regulations) in cases where inert gases are added and for other miscellaneous scenarios which decrease the NHV content of the inlet stream gas to all flare and ECD for both new and existing

[43] See 40 CFR 60.5417b(d)(8)(iii)(D) and 40 CFR 60.5417c(d)(8)(iii)(D).
[44] See 40 CFR 63.670(j)(6).

sources.[45] Examples of these known operational scenarios include combining acid gas removal (AGR) system amine regenerator still column vent gas with affected facility vent gas, combining glycol dehydration unit reboiler vent gas with affected facility vent gas streams without water removal, high water content in vent streams from certain storage vessels, and enhanced oil recovery (EOR) sites in fields using water or carbon dioxide (CO_2) flooding. The EPA is finalizing recordkeeping and reporting requirements to specifically indicate whether the flare or ECD receives (or does not receive) inert gases (inerts) or other streams which may lower the NHV of the combined stream, and, if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of those inert gases or other streams.

The EPA is also finalizing, as proposed, to replace the general exemption from NHV monitoring for associated gas for any control device used at "well site affected facilities" with NHV monitoring that is more reflective of industry operations, in order to be consistent with the overall NHV monitoring requirements for all affected OOOOb and OOOOc sources.[46]

In addition, when an owner or operator chooses to meet the NHV compliance demonstration by conducting the alternative performance test via the NHV grab sampling option, the EPA is finalizing, as proposed, a clarification that sampling may be conducted upstream of the inlet to the control device, provided that the sample is representative of the gas inlet to the control device. For example, sampling may be conducted from a

[45] For the purposes of the NHV compliance provisions, inert gases (or "inerts") are gases that do not readily undergo combustion. Inert gases consist of or contain high concentrations of nitrogen, CO_2, water, or other compounds that have a net heating value of zero. *See* 90 FR 3742 (January 15, 2025).
[46] 90 FR 3746 (January 15, 2025).

location on the control device piping header, provided the sampling location is downstream of all waste gas inlets into the header.

The EPA is finalizing, as proposed, a clarification that the NHV of the vent stream must be determined in British thermal units per standard cubic feet (Btu/scf), where standard conditions are 20 degrees Celsius (°C), not British thermal units per pound (Btu/lb). If the composition is determined in weight percent, those concentrations can be used, but they will need to be converted to volume percent (equivalent to mole percent) based on the molecular weight of the constituents.

The EPA is also finalizing, as proposed, that the 14-day period for the performance test (sampling demonstration) option must be consecutive operating days, while also allowing for breaks in performance testing over weekends and holidays which may occur during the 14-day sampling period, provided that no sampling day is spaced more than 3 operating days apart from the previous sampling day.[47,48]

In addition, the EPA is specifying that for the purposes of determining the hourly average for continuous samples, the average shall be a block hourly average.[49] The EPA is not amending the sampling frequency (*i.e.*, two samples per day for 14 days with an ongoing demonstration of three samples every five years) for the performance test (sampling demonstration) option for either NSPS OOOOb or EG OOOOc.

The EPA is also retaining the one-hour minimum sampling time for the twice daily samples, except in cases where low or intermittent flow makes one-hour sampling

[47] In this context, an "operating day" is considered a normal business day of operation (*i.e.*, Monday-Friday), and weekends and holidays are considered calendar days, but not "operating days."
[48] However, if the affected source is operating during a given weekend or holiday, the facility may elect to either sample or not sample during the weekend or holiday.
[49] Each block average value for each 1-hour period (or shorter periods) are to be calculated from all measured data during each period. If the inlet stream is continuously sampled for 14 days, the hourly block average will be determined on a noon to 1 pm, 1 pm to 2 pm, etc. basis.

infeasible for both NSPS OOOOb and EG OOOOc sources. In such a case, the EPA is allowing less than one-hour sampling times, provided that the sampling time used and the reason for the reduced sampling time is documented and reported.

The EPA is finalizing, as proposed, a clarification in both NSPS OOOOb and EG OOOOc to more clearly allow the use of the sampling methodology alternative to the continuous monitoring in 40 CFR 60.5417b(d)(8)(iii) for all types of air- and steam-assisted flares or ECD.

Finally, for NSPS OOOOb, the EPA is retaining the NHV_{cz} and NHV_{dil} monitoring requirements but more clearly including the provisions at 40 CFR 60.5417b(d)(8)(vi) to allow for the use of approved alternative test methods as provided in 40 CFR 60.5412b(d)(1)(i) and (ii) for continuous monitoring of NHV_{cz} and, if applicable, NHV_{dil}. We are also finalizing, as proposed, a clarification in 40 CFR 60.5417b(d)(8)(iv) regarding when flare flow or assist rates are not required to be monitored. In addition, as proposed, for EG OOOOc, the EPA is removing the requirement to comply with and conduct monitoring for NHV_{cz} and NHV_{dil} for air- and steam-assisted flares and ECD used for existing sources. This series of revisions in EG OOOOc includes changes in the initial compliance requirements for air- or steam-assisted flares or ECD in 40 CFR 60.5412c, the continuous compliance requirements for these control devices in 40 CFR 60.5415c, and the continuous monitoring requirements for these control devices in 40 CFR 60.5417c. We are also finalizing, under EG OOOOc, that air- or steam-assisted or flares or ECD must meet an increase in the minimum NHV in the vent gas from 270 to 300 Btu/scf.

C. Correction of Inadvertent Deletion of Regulatory Text

As discussed above, in the July 2025 IFR, the EPA amended certain compliance deadlines and timeframes for implementation in response to information received after promulgation of the 2024 Final Rule to address significant concerns that certain regulatory provisions in the March 2024 Final Rule were not workable or contained problematic regulatory language that prevented compliance. On December 3, 2025, the EPA published a final rule that included discrete changes to specific regulatory text within 40 CFR Part 60 subpart OOOOb (December 2025 Final Rule).[50] Specifically, the EPA finalized amendments to the compliance deadline for NHV monitoring and provided additional time for the submission of initial annual reports at 40 CFR 60.5420b(b). The amendatory instructions for the final rule inadvertently amended all of 40 CFR 60.5420b(b) paragraph (b) in lieu of just the introductory text for paragraph (b), as intended. This resulted in the erroneous deletion of paragraphs 40 CFR 60.5420b(b)(1) through (15), which was neither intended nor proposed.

To correct this inadvertent error, the EPA is finalizing a technical correction to reinstate regulatory text for the reporting requirements in 40 CFR 60.5420b(b)(1) through (15). The substance of the December 2025 Final Rule remains unchanged by reinstating this erroneously-deleted regulatory text. Section 553(b)(B) of the Administrative Procedure Act, 5 U.S.C. 553(b)(B), provides that, when an agency for good cause finds that public notice and comment procedures are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. The EPA has determined that there is good cause for

[50] 90 FR 55671 (December 3, 2025).

making this technical correction final without prior proposal. Such notice and opportunity for comment is unnecessary, as this technical correction restores the unintentional deletion of regulatory text made by the regulatory revisions associated with the December 2025 Final Rule.

The application of the APA's "good cause" exemption in this final rule is limited to correcting the inadvertent deletion of 40 CFR 60.5420b(b)(1) through (15) and does not extend to any other portion of this final rule. Further, by correcting this unintentional error, EPA is not reopening any issues from the December 2025 Final Rule or the associated IFR from July of 2025.

IV. Significant Comments and Changes Since Proposal for NSPS OOOOb and EG OOOOc (January 2025 Proposal)

This section of the preamble presents in each subsection a detailed summary of the significant comments received on, and changes made, since the January 2025 Proposal for the topic addressed in that subsection. This final action does not address or take any position on the best system of emission reduction (BSER) analysis included in the March 2024 Final Rule record which the EPA used to support promulgation of the standards included in NSPS OOOOb and the presumptive standards included in EG OOOOc.

The EPA's full response to comments on the January 2025 Proposal, including any comments not discussed in this preamble, is available in the EPA's Response to Comment (RTC) document for this final rule.[51]

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[51] Reconsideration of 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 January 2025 Proposed Rule (90 FR 3734; January 15, 2025). Included in Docket ID EPA-HQ-OAR-2024-0358.

A. Temporary flaring provisions for associated gas in certain situations

For oil wells that are not routinely flaring (*i.e.*, wells that route associated gas to sales lines or an equivalent alternative), the March 2024 Final Rule allowed owners and operators to route associated gas to a flare or control device in certain situations for 24 hours. These situations include times when there is a need to flare due to malfunctions, including for safety reasons. Further, these situations may include repair, maintenance (including blowdowns), bradenhead test, packer leakage test, production test, or commissioning. As stated in the January 2025 Proposal, industry petitioners seeking reconsideration claimed that the 24-hour limitation for temporary flaring is not sufficient for malfunctions, including for reasons of safety, and/or for repair and maintenance. Additionally, they claimed well sites may not be accessible during weather events (*i.e.*, winter storms), which are a significant factor for temporary flaring that lasts for more than 24 hours. Industry petitioners maintained that a 72-hour timeframe is more appropriate for temporary flaring due to the unique characteristics of each wellsite, weather conditions, or a combination of both. In the January 2025 Proposal, the EPA proposed to allow 48 hours for temporary flaring based on submitted industry data. The EPA agreed that the data showed that 24 hours was insufficient to resolve all malfunction, maintenance, and repair events. In the January 2025 proposal, the EPA also solicited comments on allowing owners and operators of associated gas affected facilities to route to a flare or control device for up to 72 hours if exigent circumstances exist, since the industry indicated that some events last for more than 48 hours. In particular, the EPA solicited comments on whether there are other specific exigent circumstances for which the EPA should consider allowing an owner or operator to route to a flare or control device beyond the proposed 48-hour allowance for repairs and malfunctions. Furthermore, the EPA solicited comments on recordkeeping and reporting requirements if the EPA were to include an allowance for owners or operators of associated gas affected facilities to route to a flare or control device for up to 72 hours for exigent circumstances.

The EPA received several comments on this aspect of the January 2025 Proposal. The EPA received comments on exigent circumstances, the temporary flaring timeframe, and recordkeeping and reporting requirements. These comments and the EPA's responses are provided in sections IV.A.1 through 4 of this preamble. The EPA also received comments requesting alternative exemptions and cutoffs to limit temporary flaring. These comments and the EPA’s responses are provided in section IV.A.5 of this preamble. The EPA’s full response to comments on the January 2025 Proposal, including any comments not discussed in this preamble, is available in the EPA’s RTC document for the final rule.

1. Exigent Circumstances

In the January 2025 Proposal, the EPA solicited comment on allowing owners or operators of associated gas affected facilities to temporarily route the associated gas to a flare or control device for up to 72 hours in certain situations if exigent circumstances exist. Such exigent circumstances would include situations where an owner or operator cannot physically access a site due to weather or other conditions (*e.g.*, road closures). In addition to extreme weather events and road closures, the EPA solicited comment on whether there are other specific exigent circumstances for which the EPA should consider allowing an owner or operator to route to a flare or control device beyond the proposed 48-hour allowance for repairs and malfunctions. The EPA received several comments on this aspect of the January 2025 Proposal. These comments and the EPA responses are provided in this section of the preamble.

Comment: Several commenters requested that the EPA include other exigent circumstances in addition to those proposed. One commenter requested that the EPA clarify that exigent circumstances include, but are not limited to, flooding, road washouts, fires and explosions, personnel shortages due to illness or labor disputes, wildfires, earthquakes, hazmat emergencies, evacuation orders, war or civil unrest, and equipment supply chain issues.[52]

Another commenter[53] noted that, as stated in previous comments they submitted on the December 2022 Supplemental Proposal,[54] it is often necessary to temporarily route gas to control devices for safety and/or operational purposes in situations when associated gas could not be routed to a sales line or used for other beneficial purposes. The commenter requested that the EPA provide additional flexibility to allow temporary routing of gas to control devices when other exigent circumstances exist, including, but not limited to, interruption in service, extreme weather events, and road closures that prevent access to sites. The commenter stated that the January 2025 Proposal cites an API survey that concluded the average duration for temporary flaring was 46 hours per event. While the changes in the January 2025 Proposal to allow temporary flaring from 24 to 48 hours might accommodate the average temporary flaring event determined in the study, the commenter urged the EPA to consider allowing temporary flaring of 72 hours or more to account for the varying configurations of well sites and exigent circumstances.

[52] Document ID No. EPA-HQ-OAR-2024-0358-0082.
[53] Document ID No. EPA-HQ-OAR-2024-0358-0085.
[54] Docket ID No. EPA-HQ-OAR-2021-0317.

Consistent with the previous comment, another commenter noted that the EPA requested input on other exigent circumstances that warrant flaring beyond 48 hours.[55] The commenter listed inclement weather, site access, operations outside normal business hours, availability of service providers and equipment, safety of operator personnel or the public, and repair, maintenance, production testing, or commissioning as exigent circumstances warranting longer flaring times. However, the commenter recommended that the EPA allow other scenarios when 72 hours of flaring would result in lower emissions than the alternative, *e.g.*, shutting down a facility requiring blowdowns that vent emissions to the atmosphere resulting in greater emissions as compared to those from flaring. As such, the commenter requested that the EPA consider all exigent circumstances to include situations where the alternative operation would result in more emissions, rather than allowing flaring for 72 hours.

Response: As noted in section III.A.4 of the January 2025 Proposal (Basis for Proposed Changes), the EPA acknowledges that there are special situations where a longer timeframe than proposed may be needed and such circumstances may be beyond the owner's and operator's control. While the EPA agrees with some commenters that other exigent circumstances should be included in addition to extreme weather events and road closures, not every situation suggested by commenters qualifies as an exigent circumstance. As explained in section III.A of this preamble, the events that qualify for the exigent circumstances extension should be severe in nature and have a direct impact on the owner's or operator's ability to physically access the site with the necessary equipment and personnel to address the equipment malfunction incident which caused the

[55] Document ID No. EPA-HQ-OAR-2024-0358-0095.

need to temporarily flare. For instances where there is a need to flare beyond 72 hours due to an unexpected malfunction event and equipment and/or personnel are not readily available due to supply chain issues and/or temporary personnel shortages due to reasons beyond an owner's or operator's control, the EPA agrees that allowing an owner or operator to flare beyond 72 hours meets EPA's intent of what is considered an “exigent circumstance” and we revised the final rule to specifically allow flaring beyond 72 hours for such instances. While the EPA acknowledges that there may be instances when extraordinary circumstances, such as a national pandemic which is beyond an owner's or operator's control, could result in a temporary shortage of personnel being available to resolve an unexpected malfunction or to access a facility within 72 hours of an event, we do not consider personnel shortages due to illness or labor disputes to qualify as exigent circumstances. Personnel shortages due to illness or labor disputes are best characterized as an internal operational matter for which the owner or operator holds primary responsibility and is expected to manage through appropriate contingency planning.

To address commenters' concerns, the final rule defines an "exigent circumstance” to be a situation that results in the inability to reasonably access a site with the necessary equipment and personnel to address and resolve incidents that cause the need to temporarily flare associated gas for more than 72 hours. This includes circumstances where there is a need to flare beyond 72 hours due to an unexpected malfunction event and equipment needed to resolve an incident are not readily available due to an owner's or operator's inability to secure the required equipment for reasons beyond an owner's or operator's control (*i.e.*, supply chain issues); or there is a temporary shortage of personnel needed to resolve an incident due to a circumstance such as a declared national pandemic that is beyond an owner's or operator's control.

To address a commenter’s request that we allow flaring for exigent circumstances to include situations where an alternative operation would result in more emissions rather than allowing flaring for 72 hours, we revised the final rule to allow flaring for up to 72 hours and beyond 72 hours for exigent circumstances, reducing the need for well shut ins.

In this final action, we are revising the March 2024 Final Rule to allow temporary flaring of associated gas for up to 72 hours for situations where the owner or operator cannot comply with the standard due to malfunctions, including reasons for safety, repairs, and maintenance. For exigent circumstances, an owner or operator can temporarily route to a flare or control device for durations over 72 hours until an exigent circumstance is no longer present. Following the new temporary flaring timeframe extension and clarification of what constitutes an exigent circumstance as stated in section III.A of this preamble, we disagree that some of the events listed by commenters (operations outside normal business hours, availability of service or equipment, safety of the operator or the public, and activities like repair, maintenance, production testing, or commissioning) on their own qualify as exigent circumstances. In these instances, an owner or operator will have up to 72 hours to resolve equipment malfunctions, which is in line with what the commenter requested. However, we also acknowledge that some of these situations may fall under an exigent circumstance if the necessary equipment and personnel are not available to resolve a malfunction incident within a 72 hour timeframe due to circumstances that are beyond an owner's or operator's control, or access to a site is restricted due to worker safety (*e.g.*, if traveling to the site is unreasonably dangerous due to a wildfire). After invoking exigent circumstances, flaring can continue until the equipment malfunction incident is resolved. However, this must be no longer than 72 hours after the site can be accessed, and the necessary equipment and personnel are obtained (72 hours after the exigent circumstances which prevented access and equipment malfunction repair are no longer present).

2. Allowance for Temporary Flaring of 72 Hours or More

In the January 2025 Proposal, the EPA proposed extending the allowable time for temporary flaring of associated gas during malfunctions, including for reasons of safety and during repair and maintenance. The proposed allowable timeframe was 48 hours, an increase from 24 hours in the March 2024 Final Rule. In response, several commenters requested that the EPA further extend the temporary flaring allowance to 72 hours. These commenters argued that a longer duration would better reflect field conditions, particularly in areas where access to equipment or personnel is delayed due to weather, geography, or other logistical barriers. They stated that even with proactive planning, certain malfunctions or maintenance activities may require more than 48 hours to resolve. The commenters also noted that forcing operators to end flaring before the issue is resolved could create safety risks or lead to unnecessary equipment shutdowns.

Other commenters disagreed and urged the EPA to retain the original 24-hour limit or allow for extensions only when operators clearly justify the need based on specific facts. They expressed concern that a blanket 72-hour window could weaken enforcement and lead to longer periods of uncontrolled emissions. They emphasized the need for clear limits to ensure that temporary flaring remains a last resort and is used only when necessary. The API data submitted to the EPA along with information from other stakeholders[56] show a range of flaring durations, with a notable percentage of events exceeding both 24 and 72 hours. These data suggest that while an extended flaring duration is not the norm, it does occur with some regularity, especially in cases involving equipment failure, inclement weather conditions and/or limited site access. Several comments were received on this aspect of the January 2025 Proposal. These comments and EPA's responses are provided in this section of the preamble.

Comment: One commenter[57] appreciated the EPA's acknowledgment that a 24-hour limit on temporary flaring during situations they describe as "Critical Circumstances" (*e.g.*, due to a malfunction or incident that endangers the safety of operator personnel or the public or during repair and maintenance activities) is often infeasible and warrants additional time, particularly for remote, unmanned sites in areas prone to extreme weather events and poor road conditions.[58] However, they expressed that they do not believe that the proposed 48-hour allowance will allow sufficient time to fix the problem and return the site to normal operations such that temporary flaring can stop during many "critical circumstances." The commenter suggested that a 72-hour temporary flaring duration would provide sufficient time to respond to, troubleshoot, and repair equipment during most, but not all, "critical circumstances" in areas where extreme weather and road conditions are frequent, such as during the winter months in North Dakota.[59] Further, the commenter added that these repairs are often dangerous to

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[56] Docket ID No. EPA-HQ-OAR-2024-0358.
[57] Document ID No. EPA-HQ-OAR-2024-0358-0092.
[58] The EPA notes that while the commenter uses the term "Critical Circumstances," we interpret this to mean "exigent circumstances."
[59] To date, Hess (the commenter) has provided the EPA with extensive documentation of circumstances affecting its Williston Basin production operations that necessitate up to 72-hours for temporary flaring in these circumstances. See November Hess Presentation; Hess Corporation, Hess Briefing for EPA: Oil and Natural Gas Final Methane Rule NSPS OOOOb and EG OOOOc, EPA-HQ-OAR-2024-0358-0020 (Feb.

undertake due to the extreme weather in, for example, North Dakota's Williston Basin. For instance, the commenter reported that on February 10th, 2025, the National Weather Service issued an Extreme Cold Warning in the majority of counties in North Dakota, advising that "life threatening wind chills as low as 55 below zero could cause frostbite on exposed skin in as little as 5 minutes."[60] The National Weather Service also advised to take precautions "if you must go outside."[61] The commenter stated that requiring operators to undertake immediate repair work in these conditions can unnecessarily put them in harm's way. For those "critical circumstances" that would otherwise require longer than 72 hours, the commenter noted that operators "must innovate and improve their maintenance, response, and repair practices to meet what would remain a challenging deadline in many instances."

The same commenter provided that, in the January 2025 Proposal, the EPA cited survey data provided by API (the "Temporary Flaring Survey") to support extending the temporary flaring allowance up to 48 hours.[62] The EPA proposed extending the temporary flaring allowance from 24 to 48 hours in the January 2025 Proposal based on the Temporary Flaring Survey's average flaring duration time of 46 hours. In doing so, the commenter asserted that the EPA ignored that the data shows the average flaring

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29, 2024) ("February Hess Presentation"); Hess Corporation, Hess Briefing for EPA: NSPS OOOOb Safety, Malfunction & Repair Temporary Flaring Allowance, EPA-HQ-OAR-2024-0358-0031 (June 3, 2024) ("June Hess Presentation"); Hess Corporation, McKenzie County Frost Restrictions, EPA-HQ-OAR-2024-0358-0037 (July 19, 2024); Hess Corporation, Examples of North Dakota Road Closures and Restrictions, EPA-HQ-OAR-2024-0358-0037 (July 19, 2024); Hess Corporation, Hess EO 12866 Meeting with OMB/OIRA: Oil and Natural Gas NSPS OOOOb and EG OOOOc Reconsideration Proposal, 13, EPA-HQ-OAR-2024-0358-0038-0046 (Nov. 7, 2024) ("November Hess Presentation").

[60] National Weather Service, NWS Alerts, *https://alerts.weather.gov/search?history=1&zone=NDZ009* (last visited Feb. 28, 2025).

[61] Id.

[62] See American Petroleum Institute, Operator Survey: Temporary Flaring, 4, EPA-HQ-OAR-2024-0358-0038 (July 2024) ("Temporary Flaring Survey").

duration is not uniform across basins. According to the commenter, both the Temporary Flaring Survey and the commenter's own data[63] demonstrate that the widely dispersed facilities and extreme winter weather conditions in the Williston Basin (North Dakota and Montana) can necessitate longer temporary flaring for responding to "Critical Circumstances" other than warmer and more easily accessed basins, like the Permian Basin (Texas and New Mexico). They highlighted that the Temporary Flaring Survey data shows that Williston Basin flaring incidents exceeded 72 hours in 78 percent of the reported data, compared to just 11 percent in the Permian Basin.[64] For the Permian Basin, they highlighted that 12 percent of flaring events exceeded 24 hours, claiming that where flaring exceeded 24 hours, it is extremely probable the flaring continued beyond 72 hours. The commenter reported that its extensive temporary flaring data (*e.g.* Temporary Flaring Survey) shows that an average of approximately 72 hours of temporary flaring is necessary during their "Critical Circumstances." The commenter asserted that the data and information provided by both API and Hess suggest that a 72-hour temporary flaring duration allowance is an appropriate default for a nationwide rule.[65]

The commenter added that it provided temporary flaring data that reflected events that it had identified internally as the highest priority of work ("break-in work").[66] The

[63] Hess's operations in the Bakken formation span roughly 7,200 square miles and include many unmanned sites. Hess provided information demonstrating that it often cannot physically access a site within 48 hours, and seasonal conditions and extreme weather events may delay accessibility for days and up to over a week until access roads to a wellsite are passable. See November Hess Presentation at 10.
[64] Temporary Flaring Survey at 6.
[65] See Hess Corporation, Hess EO 12866 Meeting with OMB/OIRA: Oil and Natural Gas NSPS OOOOb and EG OOOOc Reconsideration Proposal, 13, EPA-HQ-OAR-2024-0358-0046 (Nov. 7, 2024) ("November Hess Presentation").
[66] Hess's "highest priority notifications" response system prioritizes repair work that can result in temporary flaring above previously scheduled work. Hess provided the EPA with data showing that the average notification creation to resolution cycle times between 2020 and 2024 averaged 3.2 days. See June Hess Presentation at 12.

commenter explained that this is the priority given to “Critical Circumstance” responses. The commenter added that its sites are often not accessible within 24 hours due to difficult terrain, long travel distances between facilities, and extreme weather. These conditions are an impediment to the first step in response: travelling to the facility to investigate the cause of the “Critical Circumstance.” The commenter added that its data show the average response time from notification creation to resolution was slightly more than 72 hours; however, as an average implies, many events lasted longer than 72 hours. The commenter contended that its data demonstrate that 48 hours is often not long enough to travel to the facility, troubleshoot, obtain necessary equipment, and complete repair, even with normal business processes that incorporate efficiencies.[67] The commenter asserted that the EPA’s proposed 48-hour limit inappropriately relied on a summary report from New Mexico and from a Colorado regulation to assert that a 48-hour period is sufficient for temporary flaring for malfunction/safety and repair/maintenance situations. However, the commenter noted that areas such as North Dakota are subject to more frequent and more extreme weather events than those areas.

In addition, the commenter explained that oil and gas facilities in North Dakota are spread across expansive and geographically remote locations.[68] The commenter expressed that it does not believe it is appropriate to finalize a one-size-fits-all approach based on these two unique States (*i.e.*, Colorado and New Mexico). Moreover, the commenter reiterated that the Permian Basin data in the Temporary Flaring Survey shows

[67] Under Hess’s “highest priority notifications” response system, it can still sometimes take up to 21 hours for an operator to access the facility and identify the problem necessitating the temporary flaring. If a maintenance crew is required for repair, it can take multiple days even with equipment available. See June Hess Presentation at 12.
[68] See Hess Corporation, Hess’ Bakken Operating Area, EPA-HQ-OAR-2024-0358-0038-0037_attachment 1 (July 19, 2024).

that where flaring exceeded 24 hours, it is extremely probable that flaring exceeded 72 hours. In conclusion, the commenter argued that a blanket 72-hour temporary flaring allowance for “Critical Circumstances” provides a more reasonable timeframe and will force operator innovation.

Conversely, another commenter urged the EPA not to allow operators to temporarily route associated gas to a flare or control device for up to 72 hours for weather-related delays.[69] The commenter did not support any additional allowances for temporary flaring for up to 72 hours. In the commenter’s opinion, the Temporary Flaring Survey does not support the need for a 72-hour allowance for weather-related delays. The commenter reported that only three percent of the total data demonstrated that inclement weather was the cause of needing time to mitigate flaring with an average duration of 21 hours of temporary flaring per event.

The commenter also pointed to the Temporary Flaring Survey data on reportable emission events from the 2021 winter storm Uri that impacted Texas.[70] The data includes all reportable emission events the Texas Commission on Environmental Quality (TCEQ) received from all industry sectors in the State. The commenter expressed that it is vital that the EPA examines this data in more detail before moving forward with any extension of temporary flaring duration based on weather. The commenter highlighted that the TCEQ dataset includes 328 emission events, but 78 percent of those events occurred at facilities that are not upstream oil and gas facilities and argued that those events are therefore not relevant to any decision to allow for extended flaring due to inclement weather.

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[69] Document ID No. EPA-HQ-OAR-2024-0358-0096.
[70] See API, Document ID No. EPA-HQ-OAR-2024-0358-0038, attachment 6.

Response: The EPA appreciates the information and insights provided by commenters and agrees overall with the recommendations for extending the temporary flaring allowance to 72 hours. We agree with the commenters that the proposed 48-hour temporary flaring limit, while directionally helpful, does not adequately address the logistical complexities present in the widely dispersed locations in the oil and gas industry. Allowing for up to 72 hours promotes administrability and equitable treatment among sites for the vast majority of flaring incidents discussed in this preamble, while also providing for emissions reductions in tandem with the requirement that sources stop flaring as soon as the qualifying incident is resolved. Compliance with these requirements will be reported to the EPA and enforced through a combination of new (finalized in this rule) and preexisting (from the 2024 rule) emissions-reporting obligations, and many facilities have an independent economic incentive to cease unnecessary flaring where the gas could otherwise be captured and sold.

The Temporary Flaring Survey indicates that more than 17 percent of flaring events required more than 24 hours of temporary flaring of associated gas per event, and more than 15 percent of flaring events required more than 72 hours of temporary flaring per event. The causes of these extended flaring durations were multifaceted and included inclement weather, primarily in the Williston Basin which routinely faces harsh winter weather conditions, and other factors such as the unique characteristics of each wellsite (unmanned, remote, and dispersed).

Critically, weather is not the only contributor to extended flaring events, as demonstrated in the dataset and comments provided by petitioners. Information gathered from industry meetings and the Temporary Flaring Survey indicate that these logistical challenges exist regardless of weather and are often intensified by routine operational hurdles such as scheduling contractor support, transporting heavy equipment, and adhering to internal safety procedures. Further analysis reveals the Temporary Flaring Survey reported 86 flaring events as weather-impacted events, and the survey classified over 600 flaring events as “[u]nknown.” While we do not know the cause of the need to flare for the over 600 flaring events in the Temporary Flaring Survey, maintaining a 24-hour, or even 48-hour, flaring timeframe based on the percentage of reported inclement weather-impacted events presents a narrow reading of the data and does not reflect the "[u]nknown" flaring events that exhibited the highest flaring durations and standard deviations. The commenter's argument centers on a narrow interpretation of weather-related flaring events that indicates that only three percent of total incidents in the Temporary Flaring Survey cite weather as the cause for the need to flare and that those averaged 21 hours per event.[71] While it is true that the Temporary Flaring Survey indicates that flaring events often can be resolved quickly, the data and information provided by industry also indicate that other factors can impact an owner’s or operator's ability to limit the duration of flaring that are beyond their control. In instances where an owner or operator is able to limit the duration of flaring by addressing the cause of the need for flaring in a timely manner, an owner or operator is encouraged to limit the flaring duration to the maximum extent possible. The EPA is extending the flaring allowance based on the ability of an owner or operator to access their flaring event site and resolve the cause of the need to flare. As noted previously, while weather can be a contributing factor affecting access to a site, it is not the only potential reason limiting

[71] Document ID No. EPA-HQ-OAR-2024-0358-0096.

access to a site. As such, the EPA has extended the allowance to flare up to 72 hours in absence of an exigent circumstance and allows more than 72 hours in instances where an owner or operator makes a legitimate exigent circumstance claim that limits their ability to access and resolve the cause for a flaring event within 72 hours. This extended timeframe gives owners and operators enough time to travel to facilities (including geographically remote facilities), troubleshoot, obtain necessary equipment, and complete repairs. It also provides sufficient time to overcome many inclement weather situations. This extended timeframe, coupled with the ability to claim exigent circumstances for even more time, should limit or eliminate the need to shut-in operations in situations of temporary flaring for malfunction, safety, or maintenance.

Additionally, the Temporary Flaring Survey shows regional variation in flaring durations, as a commenter notes. For instance, 78 percent of flaring incidents in the Williston Basin exceeded 72 hours, compared to just 11 percent in the Permian Basin. This variation highlights that a rigid one-size-fits-all approach based exclusively on national averages, and which does not allow for any flexibility, does not account for critical differences in field conditions, wellsite uniqueness, or operational complexity. The data confirm that events where flaring exceeds 24 hours often continue well beyond 72 hours. As such, setting the upper limit at 72 hours with the possibility of additional time for exigent circumstances better aligns with field data, while still placing expectations on owners and operators to promptly resolve issues.

As explained in sections IV.A.4 (Support for a 24-hour Allowance for Temporary Flaring) and IV.A.5 (Consideration of Additional Limitations and Targeted Exceptions to Temporary Flaring) of this preamble, the EPA considered but did not adopt several approaches raised by petitioners and public comments on the proposal, including a 24-hour or 48-hour flaring allowance and additional temporary flaring limits or targeted geographical exceptions.

3. Recordkeeping and Reporting

In the proposed rule, the EPA also solicited comment on the recordkeeping and reporting requirements if the Agency were to include an allowance for owners or operators of associated gas affected facilities to route to a flare or control device for up to 72 hours for "exigent circumstances."[72] The topics of exigent circumstances and temporary flaring duration are discussed more in section IV.A.1 and IV.A.2 of this preamble respectively. Specifically, we solicited comment on requiring an owner or operator who must make use of the extended timeframe to maintain records that include a written description of the exigent circumstance, the rationale for the need to route to a flare or control device beyond the default allowable timeline, a description of the measures taken to minimize temporary flaring/routing to a control device, and the duration of temporary flaring/routing to a control device due to the identified exigent circumstance. Lastly, we solicited comment on requiring an owner or operator to include a summary of their exigent circumstance recorded events in their annual report.

The EPA received two groups of comments about recordkeeping and reporting requirements for exigent circumstances. Support for recordkeeping and reporting came from environmental groups, who argued that these requirements are important for accountability, ensuring the flaring event was an appropriate action, and encouraging owners and operators to limit flare durations. Industry commenters opposed this proposed

[72] 90 FR 3740-41 (January 15, 2025).

requirement. They argued that extending recordkeeping and reporting requirements for exigent circumstances would not provide any environmental benefit and would not expedite the repair or maintenance process. Industry commenters further asserted that having additional recordkeeping and reporting provisions would add unnecessary burden to owners and operators at a time when they should prioritize resources to address the emergency or maintenance event.

Based on comments received and EPA's decision to broaden what constitutes an "exigent circumstance" to include instances where the necessary equipment and/or personnel are not available to conduct the necessary repairs for reasons beyond an owner's or operator's control, the EPA is finalizing the following recordkeeping and reporting requirements when an exigent circumstance is invoked: a written description of the "exigent circumstance" requiring the need to flare or route to a control device beyond 72 hours; a description of the steps taken to resolve the need for temporary flaring/routing to a control device; the dates and times an identified "exigent circumstance" started and ended (*e.g.*, when owners or operators are able to access site, when personnel and/or equipment are available) and the total duration of each "exigent circumstance"; and the dates and times temporary flaring/routing to a control device started and ended and the total duration of temporary flaring/routing to a control device due to the identified "exigent circumstance." We require owners and operators to report this information in their annual report. See section IV.A.1 of this preamble for comments received on exigent circumstances and EPA's response to those comments.

As mentioned above, we received several comments on this aspect of the January 2025 Proposal. These comments and the EPA responses are provided in this section of the preamble.

Comment: Several industry commenters did not support the EPA requiring records and reporting (in annual reports) of information regarding exigent circumstances necessitating temporary flaring beyond the default time allowance. One commenter[73] stated that operators should focus on resolving emergencies and/or maintenance issues that arise to reduce and/or remove the need to flare, instead of recordkeeping and reporting requirements that provide no environmental benefit.[74] Additionally, according to the commenter, such recordkeeping and reporting causes burden for the operator and the EPA. The commenter requested that the EPA implement a blanket timeframe of at least 72 hours for temporary flaring without the need for recordkeeping and reporting such events.

Similarly, one commenter[75] noted that the additional administrative recordkeeping and reporting burden to conduct, document, and report an exigent circumstance would not provide a corresponding environmental benefit.[76] The commenter stated that the NSPS OOOOb and EG OOOOc rules already require recordkeeping and reporting for temporary flaring events that are sufficient to provide transparency into operators' temporary associated gas flaring activities.

[74] Document ID No. EPA-HQ-OAR-2024-0358-0095.

[76] Document ID No. EPA-HQ-OAR-2024-0358-0092.

Another commenter expressed concern about the documentation required for exigent circumstances, stating that it is unnecessary and unduly burdensome as a blanket 72-hour allowance is warranted.[77]

Conversely, another commenter expressed that if the EPA finalizes a nationwide exception for exigent circumstances, then the EPA must add specific recordkeeping and reporting requirements to the rule.[78] The commenter supported the recordkeeping and reporting that the EPA listed in the proposal as a minimum requirement to document and justify any temporary flaring or routing to control devices that goes beyond the baseline limit. The commenter asked that this documentation include a description of the circumstance requiring extended flaring, the rationale for routing to a flare or control device beyond the allowed limit, documentation from public information that supports the claim that extended flaring was necessary (*e.g.*, traffic information showing road closures), a description of the measures taken to minimize temporary flaring, and the duration of temporary flaring. Also, the commenter requested that the annual report require a summary of the number, cause, and duration of extended flaring events.

Response: The EPA agrees that the near-term focus of owners and operators in these situations should be on the immediate need of resolving emergencies and/or maintenance issues as quickly as possible to mitigate the need to flare. However, we disagree that recordkeeping and reporting is unnecessary and that any such requirements will cause undue burden to the owners and operators. First, base-level recordkeeping and reporting requirements already exist for owners and operators in the regulations (40 CFR 60.5420b(b)(4)(i) and (2) and (c)(3) (i) and (ii); and 40 CFR 60.5420c(b)(3)(i) and (ii)

[77] Document ID No. EPA-HQ-OAR-2024-0358-0088.
[78] Document ID No. EPA-HQ-OAR-2024-0358-0096.

and (c)(2)(i) and (ii)) for all temporary flaring that are not at issue in this rulemaking. Including exigent circumstance recordkeeping and reporting only adds additional requirements when an exigent circumstance occurs. Thus, if the exigent circumstance provision is not invoked, owners and operators are not required to complete any additional recordkeeping and reporting beyond the base-level requirements for all temporary flaring situations. The additional information that we will collect for exigent circumstances does not duplicate the base-level recordkeeping requirements included in the March 2024 Final Rule and is not time-consuming or resource intensive.

Second, requiring additional recordkeeping and reporting for exigent circumstances documents compliance with the allowance for temporary flaring beyond 72 hours for exigent circumstances. Specifically, the additional recordkeeping and reporting requirements only apply when an owner or operator invokes an extension of flaring duration due to an exigent circumstance and only includes minimal documentation to ensure that owners and operators are properly invoking and implementing the flaring extension.

Lastly, in response to comments that claim that owners and operators should first focus on returning the site to normal operations, the EPA agrees. The recordkeeping requirements included in the final amendments can be completed after the owner or operator addresses the underlying issue that gave rise to the need for temporary flaring. None of the recordkeeping requirements mandate action contemporaneous with conducting repair or maintenance. The recordkeeping can occur after repair or maintenance but should happen relatively close in time so that the owner or operator can record accurate information.

4. Support for a 24-hour Allowance for Temporary Flaring

Following the January 2025 Proposal, several industry representatives and State agency commenters recommended extending the temporary flaring allowance to 72 hours. In contrast, other commenters, including environmental organizations and private citizens, urged the EPA to retain the original 24-hour limit from the March 2024 Final Rule, with limited allowances for extensions up to 48 hours in exigent circumstances or until the event is resolved. As part of the proposed rule, the EPA requested data and feedback on whether the revised flaring duration could potentially increase primary or secondary emissions and invited additional information to either substantiate the proposed 48-hour allowance or justify maintaining the 24-hour duration in the March 2024 Final Rule.

The EPA received several comments on this aspect of the January 2025 Proposal. These comments and the EPA's responses are provided in this section of the preamble.

Comment: Two commenters requested that the EPA retain the 24-hour allowance for temporary flaring.[79] One commenter disagreed with the EPA's determination that the information provided in the Temporary Flaring Survey supports allowing temporary flaring for up to 48 hours during malfunctions but believes the information provided in the Temporary Flaring Survey supports retaining the 24-hour allowance, potentially with limited exceptions.[80] The commenter agreed with the EPA's statement that the Temporary Flaring Survey supports an expectation "that owners and operators can feasibly limit temporary flaring to less than 24 hours in a large majority of situations."[81]

[79] Document ID Nos. EPA-HQ-OAR-2024-0358-0080, EPA-HQ-OAR-2024-0358-0096.
[80] Document ID No. EPA-HQ-OAR-2024-0358-0096.
[81] 90 FR at 3740 (January 15, 2025).

The commenter stated that the Temporary Flaring Survey had 2,804 instances of temporary flaring of associated gas at sites in the San Joaquin, Permian, and Williston Basins.[82] According to the U.S. Energy Information Administration (EIA), the primary producers of associated gas in the U.S. are the Permian, Bakken, Eagle Ford, Anadarko, and Niobrara Basins.[83] The commenter observed that the Temporary Flaring Survey did not include any information on temporary flaring in the other three basins identified by the EIA. For the EPA to justify a nationwide change, the commenter contended that the agency should examine data from all basins where associated gas is primarily produced (and thus has the greatest potential for a need to temporarily route to a flare or control device) to determine whether the current allowance of 24 hours is appropriate. According to the commenter, the Temporary Flaring Survey does not support the EPA's proposed change to allow up to 48 hours for temporary flaring of associated gas, and data from other basins may also further demonstrate this change is not justified. The commenter asserted that the Temporary Flaring Survey therefore is not complete enough to justify an alteration of the standard for the entire country.

Additionally, the commenter stated that an analysis of the Temporary Flaring Survey shows the average duration of temporary flaring of associated gas is 46 hours, which the EPA used as the basis for its proposal. However, they reported that a detailed examination of this data does not support a blanket allowance of 48 hours.[84] The commenter noted that most of the data come from the Permian Basin (2,581, or 92 percent) and show that the average duration of temporary flaring was 26 hours, with 318

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[82] See API, Document ID. No. EPA-HQ-OAR-2024-0358-003, attachment 3.
[83] U.S. EIA, "U.S. associated gas production increased nearly 8% in 2023." November 13, 2024. *https://www.eia.gov/todayinenergy/detail.php?id=63704#*.
[84] See Attachments A and B of the commenter's letter.

instances requiring greater than 24 hours (12 percent of the total instances for this basin). Nearly 75 percent of the instances (1,930) are labeled as "high priority," and the average duration of temporary flaring for these events was five hours, with only 14 instances greater than 24 hours (0.7 percent). In the commenter's opinion, this demonstrates that operators can address issues, such as maintenance and safety concerns, leading to temporary flaring well within the currently allowed 24-hour duration for sites in the Permian Basin.

The commenter further observed that the 46-hour average duration in the Temporary Flaring Survey is skewed by data from the Williston Basin, representing only 166 total instances, or just six percent, of the Temporary Flaring Survey data. The commenter reported that the average duration of temporary flaring for these instances is 378 hours. Additional details provided by Hess, and within the Temporary Flaring Survey data, show that separator backpressure valve issues dominate as the cause of temporary flaring (89 percent of instances for the Williston Basin), and inclement weather is only listed as an issue for 10 instances, which have an average duration of 125 hours for temporary flaring. The commenter provided that additional information from Hess specifies these backpressure valve issues are unscheduled maintenance or malfunctions due to separator backpressure valve issues, but it is not clear whether these issues are preventable. The commenter asserted that this outlier data for the Willison Basin does not justify a blanket 48-hour nationwide allowance.

The commenter also noted that the Temporary Flaring Survey includes a total of 57 instances from the San Joaquin Basin, which is not one of the primary producers of associated gas. Moreover, the commenter indicated that the data for this basin demonstrate an ability to return to normal operations (*i.e.*, stop flaring of associated gas) after eight hours on average, with only four instances requiring more than 24 hours. The commenter pointed out that of those four instances exceeding 24 hours, three are labeled as “high priority” and the cause is listed as power failure (two instances), compressor failure (one instance), and valve failure (one instance). While these limited exceptions do exist, the commenter suggested that the overall data from the San Joaquin Basin further support the position that the EPA should retain the 24-hour allowance.

Also, the commenter evaluated data from New Mexico exploration and production operators, which the commenter claimed demonstrate that operators can comply with a 24-hour limit on temporary flaring during malfunctions or incidents that endanger the safety of operator personnel or the public, as well as during repair and maintenance activities.

The commenter argued that New Mexico requires exploration and production operators ("upstream operators") to report flaring or venting of natural gas on form C-129 “that exceeds 50 thousand cubic feet (MCF) in volume and either results from an emergency or malfunction, or lasts eight hours or more cumulatively within any 24-hour period from a single event.”[85] The report must include the time of venting or flaring and the nature and cause of the venting or flaring.[86]

The commenter evaluated all C-129 reports filed with the New Mexico Oil Conservation Commission (OCC) between 2021 and 2025.[87] The commenter reported that the database contains reports filed by upstream and midstream operators. According

[85] N.M. Admin. Code Section 19.15.27.8.G.(1)(a).
[86] Id. at Section 19.15.27.8.G.(1)(b).
[87] See Attachments C and D of the commenter’s letter for the Excel workbooks that include their analysis.

to the commenter, of all the causes listed, 13 were identified that could be classified as a malfunction or incident that could endanger the safety of operator personnel or the public or as occurring during a repair or maintenance activities. The commenter listed in their comment letter the various causes for these events, including corrosion, downhole well maintenance, equipment failure, freeze, human error, lightning, liquids unloading, overflow-tank, pit, packer leakage test, power failure, repair and maintenance, production test, and commissioning to purge.

In its analysis of the New Mexico OCC dataset, the commenter stated that 99.7 percent of the total reported flaring incidents lasted 24 hours or less. According to the commenter, this data demonstrates that operators can comply with a 24-hour limit on flaring during malfunctions or incidents that endanger the safety of operator personnel or the public and also during repair and maintenance activities.[88]

Another commenter contended that the EPA's proposal to extend the temporary flaring allowance from 24 to 48 hours and include exigent circumstances to allow flaring up to 72 hours is a massive step in the wrong direction. The commenter contended that this policy, while trying to meet the demands of a changing industry, critically ignores the health and environmental implications that the commenter attributed to flaring. The commenter stated that instead of responding to concerns raised by oil and gas companies, thereby allowing what the commenter described as further damage to health and safety, there should be more focus on stricter regulations that veer toward alternative modes of energy production.

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[88] See Attachments C and D of the commenter's letter for the Excel workbooks that include their analysis.

Response: For the reasons explained here, the EPA found comments suggesting that the EPA should retain the 24-hour allowance for temporary flaring of associated gas for malfunction, including for reasons of safety, and during all repairs and maintenance finalized in the March 2024 Final Rule to be unpersuasive. [89]

In finalizing the required timeframe for this provision, the EPA considered additional factors beyond the average flaring duration proposed in the January 2025 Proposal due to variabilities that exist in the industry at large.

Some commenters appear to suggest that a strict 24-hour limit on temporary flaring is warranted based on the claim that most events in the Temporary Flaring Survey, particularly in the Permian Basin, are resolved within that timeframe. However, this narrow interpretation of the data, when considered in the context of setting a national standard, ignores critical realities demonstrated across the full dataset and operational field conditions. First, while the Permian Basin represents a large portion of the data, flaring behavior and operational challenges do not appear to be uniform across the representative basins. Other regions, particularly the Williston Basin, face significantly harsher environmental conditions and logistical barriers that are not captured by simply focusing on Permian Basin averages. Commenters argue that because one region generally operates under favorable conditions, all other regions should be held to the same standard, an approach that is neither practical nor technically sound.

[89] With respect to the portion of the comments suggesting that the EPA should "veer toward alternative modes of energy production," the Agency first notes that such comments are out of scope for this action which concerns limited technical amendments to the temporary flaring provisions for associated gas and to NHV. Moreover, basing a regulation under Clean Air Act section 111 on a shift to "alternative modes of energy production" does not comport with caselaw. See *West Virginia v. EPA*, 597 U.S. 697 (2022).

Additionally, commenters rely on averages without giving proper weight to variability. The same dataset across all responses shows that 17 percent of flaring events lasted longer than 24 hours, and 15 percent lasted longer than 72 hours - a meaningful minority that cannot simply be ignored. Averages can hide important outliers that matter operationally. For instance, the high standard deviation of 156 hours across the full dataset demonstrates that flaring durations vary dramatically and treating all events as if they should conform to an average disregards the complex, often unpredictable nature of these unique situations that may result in routing associated gas. Emergencies, severe weather, and mechanical failures in remote, unmanned sites frequently require more than 24 hours to troubleshoot, repair, and safely restore operations.

The EPA also disagrees with the claim that the datasets and other information available to the Agency are too limited to support a nationwide 72-hour flaring allowance. While the Temporary Flaring Survey does not include every basin, it contains 2,804 flaring events from several major oil and natural gas producing regions, providing a meaningful sample of real-world operations. Events exceeding both 24 and 72 hours occurred across different categories. For example, in the "Other – specify" category of the Temporary Flaring Survey, gas sales line freezing led to flaring durations as high as 117 hours, power outages resulted in delays up to 48 hours, and high hydrogen sulfide (H_2S) levels forced compressor shutdowns lasting 29 hours. In the C-129 reports filed with the New Mexico OCC that the commenter evaluated, while these events represent a small portion of the more than 28,000 total upstream incidents examined, there were still 127 flaring incidents lasting more than 24 hours and 103 incidents lasting more than 72 hours during repair and maintenance activities. So, even the data from New Mexico shows that 24, or even 48, hours is not sufficient time in some instances. These examples show that extended flaring durations can result from malfunction or safety related issues that are not tied to any single region.

A national default limit of 72 hours is straightforward in terms of compliance, especially for operators who work in more than one basin. It gives enough time to fix most issues without needing to claim an exigent circumstance. It also avoids subjecting sources across different regions to unequal treatment, as well as avoiding situations where sources are subject to the conditions discussed above that may contribute to longer flaring incidents but are captured in the existing record or analysis. Such sources could be existing sources or new sources, and a nationwide standard for new sources obviated the need to continually analyze and adjust regional-based considerations. For rare cases that go beyond 72 hours, the rule allows limited flexibility as addressed in section IV.A.1 of this preamble. And, as discussed previously, the EPA is also requiring flaring to cease when the incident triggering flaring has been resolved, which serves as a protective backstop to reduce emissions notwithstanding the 72 hour allowance. We expect that incidents that previously have been resolved within 24 or 48 hours would continue to be resolved as quickly as practicable and that flaring would cease when the issue is resolved.

The EPA does not dispute the general idea that the data available to the Agency in this rulemaking docket demonstrate that many instances of temporary flaring of associated gas are resolved, with the site returning to normal operations, within 24 hours. However, we view this information within the context that these instances mostly occurred at sites that were not subject to 2024 final rule NSPS 24-hour limit at the time of the data collection. As such, owner and operators were already responding quickly to address repair, maintenance, and safety issues and returning their sites to normal operations (ceasing flaring) due to considerations outside the NSPS and EG. We have no reason to believe that those other considerations, whatever they may be (*e.g.*, State or local laws/regulations economic incentives to restore flow to sales lines), would vanish upon finalizing the amendments to increase the NSPS and EG timeline to 72 hours. We also have no reason to predict that allowing up to 72 hours, or more with exigent circumstances, in the NSPS and EG will result in owners and operators always taking up to 72 hours to return their sites to normal operations. It is reasonable to assume that if owners and operators were addressing these issues quickly before the NSPS, they will continue to do so after these amendments. Seventy-two hours is a limit, not a minimum. The EPA's regulations in no way interfere with the efforts of owners and operators to address problems as quickly as possible. In fact, the final regulations clarify that temporary flaring must stop when the issue giving rise to the need to flare has been resolved. The requirement only allows flaring for the duration of time necessary to return the site to normal operations. If that is accomplished in eight hours instead of 72, then the rule does not allow, let alone require, flaring for 72 hours.

The EPA finds that certain commenters overestimate the potential environmental consequences of revising the 24-hour requirement to a 72-hour requirement. If the regulations provide owners and operators with no options aside from shutting-in operations if repairs are incomplete after 24-hours, these circumstances may lead to depressurizing equipment directly to the atmosphere (*i.e.*, venting). A shut-in occurs when an owner or operator temporarily closes the valves on an oil or gas well to stop the flow of hydrocarbons, often for maintenance, safety, equipment issues, or economic issues. The act of restarting the well after a shut-in can result in significant emissions due to pressure buildup while the well was shut-in, as owners and operators perform blowdown operations to release pressure from the well, often resulting in significant releases of methane and other harmful emissions.

Venting in these situations may release far more harmful emissions than controlled flaring would over an additional 24 to 48 hours. Thus, a rigid 24-hour limit, when compared to what is being finalized, could result in marginally greater pollution, not less, undermining the EPA's emission reduction goals. Further, in accordance with 40 CFR 60.5377b(d), emissions from flares and ECD are to be controlled at 95 percent reduction efficiency (see also 40 CFR 60.5391c(b) within the model rule for the EG). While the change from 24 hours to 72 hours for flaring in these situations, and longer for exigent circumstances, can theoretically allow more flaring by total duration, the natural gas being routed to a flare during this time is still being controlled at a 95 percent reduction efficiency. And as noted above, any increase in emissions from flaring is speculative given the backstop requirement that flaring must cease as soon as the underlying issue is resolved.

Finally, while one commenter dismissed data from the Williston Basin as "outliers," this overlooks the fact that the data from the Williston Basin represent real operating conditions faced by numerous facilities.[90] The fact that the sample size from the Williston Basin is smaller does not mean that the issues operators face there are less legitimate. The EPA believes that utilizing a regulatory framework that fails to accommodate areas with severe climates and operational challenges would penalize

[90] Document ID No. EPA-HQ-OAR-2024-0358-0096.

responsible owners and operators working in these difficult environments. The information presented to the EPA clearly indicates that in some instances -and more than just a few outliers- owners and operators credibly require more than 24 hours to temporarily flare before they can resolve the problem and return the site to normal operations. It is not appropriate for the EPA to establish a rigid and universal, nation-wide, requirement that the Agency has credible reason to believe cannot be met. Allowing up to 72 hours for most situations, and providing a mechanism to go beyond 72 hours, will allow owners and operators the time they need while also ensuring that temporary flaring does not continue indefinitely or unchecked. To use an example from one commenter, flaring for 378 hours due to a separator backpressure valve issue where the site is accessible would not be in compliance with the finalized amendments. We believe that a fair and reasonable standard should reflect the full diversity of U.S. oil and natural gas operations. A flexible allowance permitting up to 72 hours of flaring under these circumstances is both more practical and environmentally responsible.

5. Consideration of Additional Limitations and Targeted Exceptions to Temporary Flaring

In response to the January 2025 Proposal to extend the allowable duration for flaring associated gas from 24 to 48 hours under certain situations, commenters also raised two distinct but related issues. The first is whether there should be a clear cutoff for flaring within the 48-hour period. Some commenters advocated for a more restrictive application of the proposed 48-hour allowance by recommending that the EPA adopt an additional cutoff mechanism. They requested that the EPA require owners and operators to stop flaring as soon as the repair, maintenance, or safety issue is resolved, even if that happens before the end of the 48-hour period. They argued that this was needed to avoid extra flaring that serves no technical purpose. For example, if a repair is done after 8 hours, the commenter asserts flaring should not continue for the full allowed temporary flaring duration. The commenter requested that the EPA clearly state that flaring must stop when the cause of the disruption is resolved.

Second, a separate set of comments urged the EPA to consider geographical targeted exemptions (*i.e.*, to explore whether exemptions to the flaring limit should apply only in certain geographic areas such as specific basins). These commenters argued that the EPA should not apply the proposed 48-hour flaring allowance across the country. Instead, they suggested that the Agency consider basin-specific exemptions where data shows they are needed. The commenters pointed to past EPA rules that have allowed for regional differences. For example, the EPA has given exemptions for Alaska North Slope facilities due to cold weather conditions. In this case, the commenter referred to the Temporary Flaring Survey data from the Williston Basin and said it does not support a nationwide change to the flaring limit. They further asserted that any extended flaring allowance based on that data should apply only in the Williston Basin.

These comments suggest that a blanket 48-hour allowance may not be the best fit for all situations. These comments and the EPA's responses are provided in sections IV.A.5.a and IV.A.5.b of this preamble.

a. Additional cutoff to limit temporary flaring

Comment: One commenter requested that, if the EPA finalizes the 48-hour allowance as proposed, the EPA explicitly include an additional cutoff for the stated allowed duration to ensure the temporary flaring or routing to control devices ceases as soon as the malfunction is resolved, including for reasons of safety, repair, or maintenance.[91] The commenter contended that it is necessary for the EPA to specifically put restrictions on the duration to require operators to stop temporary flaring when repairs or maintenance are completed, thus avoiding continued flaring longer than necessary during each incident. For example, the commenter stated that if a repair or maintenance is completed within eight hours of the need to temporarily flare associated gas, then the flaring of associated gas should be limited to eight hours, not a full 24 hours as allowed in the March 2024 Final Rule. The commenter recommended regulatory text changes to 40 CFR 60.5377b(d)(1) and (2) and 40 CFR 60.5391c(c)(1) and (2) placing a cutoff for temporary flaring to end as soon as the malfunction, safety concern, or maintenance repair is resolved, if it did not require the full 24 hours allowed in the March 2024 Final Rule.

Additionally, the commenter stated that their recommendations are consistent with other requirements in NSPS OOOOb and EG OOOOc, which place an upper limit on how long provisions for certain extenuating circumstances may apply before the baseline requirements once again take effect, including the allowance of temporary flaring until gas composition meets specifications or up to 72 hours, whichever is less (40 CFR 60.5377b(d)(4)); delayed repair of centrifugal compressors (40 CFR 60.5380b(a)(8)(i)), reciprocating compressors (40 CFR 60.5385b(a)(3)(i)), fugitive emissions components until the next scheduled shutdown or up to two years (40 CFR 60.5397b(h)(3)(i)), whichever is earliest; repairs of pressure relief devices at gas plants the next time monitoring personnel are onsite or within 30 days, whichever is sooner (40

[91] Document ID No. EPA-HQ-OAR-2024-0358-0096.

CFR 60.5400b(d)(2)). The commenter supported this additional cutoff to ensure that temporary flaring is limited as much as possible.

Response: The EPA agrees with the commenter's recommendation that the finalized time for temporary flaring allowance of associated gas should operate as a maximum timeframe. Temporary flaring or routing of associated gas to control devices should end as soon as the malfunction, maintenance, or safety issue is resolved. The EPA's intent with the provisions for temporary flaring of associated gas is to allow necessary flexibility to manage equipment issues or emergencies, while limiting emissions to those which are associated with actions that are required to fix the problem. This approach will encourage owners and operators to limit flaring to the time necessary.

The EPA agrees that there is clear precedent for this type of backstop. The March 2024 Final Rule already includes a maximum time limit of 24 hours for temporary flaring to prevent avoidable emissions during operational disruptions.[92] Adding a requirement that flaring must cease when the issue is resolved builds on this principle.

The monthly and annual datasets provided by industry stakeholders show wide variation in flaring durations. The average flaring duration across all responses was 46 hours, but the median was four hours. This gap suggests that while some events last longer, most can be resolved much sooner. In particular, several months showed high percentages of events exceeding 24 and even 72 hours—up to 34 percent and 32 percent, respectively, in January. But in other months, most events were short, with medians below five hours. These numbers support the idea that many events can be resolved well before the maximum time is reached and that a cutoff based on when the issue is fixed

[92] (Docket ID: EPA-HQ-OAR-2021-0317) Preamble, Table 17—Situations and Durations Where Associated Gas May Temporarily be Routed to a Flare or Control Device.

would reduce emissions without affecting needed flexibility. Further, in the Temporary Flaring Survey, the Williston Basin data shows that the causes of temporary flaring vary, including equipment failures like compressor shutdowns, frozen gas lines, and power outages. We believe these events do not all require the same response time. Some events can be resolved in under 10 hours. Implementing requirements to end flaring once the cause is addressed will limit emissions to what is necessary for safe and reliable operations. Industry stakeholders have repeatedly stated that owners and operators are already taking steps to reduce flaring times and that a 72-hour allowance would promote planning and operational changes to further reduce emissions.[93] The EPA concludes that a backstop limit and a requirement to stop flaring when the issue is resolved can work together to maintain the Agency's objectives while allowing industry to respond to operational needs in an efficient and timely manner.

b. Alternative exemptions (e.g., basin-specific)

Comment: One commenter suggested that the EPA consider adopting basin-specific exemptions from the temporary flaring provisions rather than extending the temporary flaring allowance beyond 24 hours for all wells nationwide.[94] The commenter acknowledged, however, that the current record does not support basin-specific exemptions. In particular, the commenter recommended that the EPA consider which limited exceptions to the 24-hour duration allowance are warranted and specify an appropriate allowance for temporary flaring or routing to control based on data that supports that exception. According to the commenter, the EPA has historically provided location-specific exceptions in its oil and gas standards that account for the unique

[93] Document ID No. EPA-HQ-OAR-2024-0358-0044.
[94] Document ID No. EPA-HQ-OAR-2024-0358-0096.

circumstances those owners and operators face. The commenter referred to a statement the EPA made: “the information provided by petitioners is persuasive in demonstrating that a blanket 24-hour limit on temporary flaring can pose compliance challenges for certain owners and operators.”[95]

The commenter summarized key observations from the 166 instances that the Temporary Flaring Survey API provided for temporary flaring of associated gas in the Williston Basin (see page nine of commenter’s letter) and concluded that the Williston Basin data provides insufficient evidence to provide a blanket nationwide exemption. The commenter further expressed that though their position is that the data are insufficiently clear to warrant adjusting the March 2024 Final Rule at this time, any change in the duration of the temporary flaring allowance based on the Williston Basin data should be limited to that basin. The commenter noted that the EPA took similar actions on limited exceptions for fugitive emissions monitoring requirements and process controllers on the Alaska North Slope, citing concerns about the technical feasibility of conducting monitoring when temperatures are below the operating envelope of the monitoring technologies, and the EPA noted “there is no assurance that the initial and semiannual monitoring that must occur during that period of time are technically feasible.”[96]

Regarding process controllers, the commenter highlighted that the EPA provided two standards for sites in Alaska in the March 2024 Final Rule: zero emissions for all process controllers at sites with access to electrical power, and the use of process controllers with low emission rates at sites with no access to electrical power (40 CFR 60.5390b(b)). Instead of the blanket move to allow 48 hours for temporary flaring as

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[95] 90 FR 3740 (January 5, 2025).

[96] 83 FR 10628, 10632 (March 12, 2018).

proposed nationwide, the commenter reiterated that any changes to the duration allowance for temporary flaring based on the Williston Basin data should be limited to the Williston Basin and based on a demonstrated need in the basin.

Response: Regarding the comment requesting that the EPA consider adopting basin-specific exemptions from the temporary flaring provisions rather than extending the temporary flaring allowance beyond 24 hours for all wells nationwide, the EPA acknowledges that we have historically allowed some location-specific variations in oil and gas standards to reflect operational challenges that are unique to certain geographic regions. However, we do not find that such an approach is necessary or supported by the current data for this rule. In the March 2024 Final Rule, the Alaska-specific provisions cited by the commenter were granted because of distinct technical challenges related to that region (*i.e.*, controllers without electric power and uniqueness of large compressors different from those in the lower 48 States[97]). For example, we took a different approach for process controllers in Alaska at sites without reliable access to power.[98] This was in part due to Alaska's northern latitude, where long periods of darkness during winter reduce the ability of solar panels to generate electricity. That situation presented a clear, location-specific operational barrier that justified a different standard for certain sources. The examples presented by the commenter both involve subcategorization that resulted in different standards for different sources. The differences there were meaningful enough to justify different treatment. However, here, the differences are not as pronounced or

[97] The "lower 48" consists of the 48 adjoining U.S. States and the District of Columbia of the U. S. The term excludes the only two noncontiguous States, which are Alaska and Hawaii, and all other offshore insular areas, such as the U.S. territories of American Samoa, Guam, the Northern Mariana Islands, Puerto Rico, and the U.S. Virgin Islands.
[98] Docket ID No. EPA-HQ-OAR-2021-0317.

meaningful, and the different treatment that commenters advocate for is only in regard to a limited variation provision that comprises one piece of the larger applicable standard (these amendments are not changing the substance of the NSPS standards or the EG presumptive standards for associated gas).

The circumstances described by the commenter and the data for the Williston Basin and other regions do not meet the same threshold as the examples that commenters cite and do not warrant the same outcome of creating subcategories. The Temporary Flaring Survey shows that 17 percent of temporary flaring events across all reported basins lasted longer than 24 hours, and 15 percent exceeded 72 hours. While these numbers suggest some operational challenges, the data also show significant variation across both the durations and underlying causes of these flaring events. For instance, the monthly flaring dataset shows that in many months, the median flaring duration was just four to six hours, even though averages were higher due to outlier events. In June and July, for example, the average flaring durations were 11 and 19 hours, respectively, with medians of four hours. This pattern suggests that while extended events do occur, many are resolved within a short timeframe, even in colder months. In the Williston Basin dataset of the Temporary Flaring Survey, temporary flaring causes range from compressor shutdowns and frozen gas lines to facility restarts and power outages. These are operational issues that may occur across multiple basins. The possibility of inclement weather as a contributing factor to site inaccessibility is not unique to any one location. The Temporary Flaring Survey shows that events flagged as "[u]nknown" accounted for a much higher average flaring duration (86 hours) compared to events where the impact of weather was known to be present (21 hours) or absent (36 hours). This inconsistency indicates that factors beyond location such as the nature of the malfunction, site accessibility, and access to equipment play a large role in extended flaring durations.

Accordingly, we find that a single, flexible nationwide approach with clear, uniform provisions for additional time is more appropriate, equitable, and easier to implement than finalizing different maximum flaring times for different geographic regions of the country. As some commenters suggested, basin-specific timelines would likely introduce unnecessary complexity into an already complex regulatory scheme, which could result in enforcement and compliance inconsistencies. The standards for associated gas are already subcategorized in the NSPS based on when a new well commenced construction. (*See* Table 16 in the March 2024 Final Rule).[99] These amendments only address two of the four scenarios for temporary flaring (*see id*. at Table 17). Further, the presumptive standards in the EG model rule are also already subcategorized on different terms than the NSPS (*see id*. at Table 4). These temporary flaring provisions are only one piece of the regulatory scheme for associated gas, and they do not relate to the standards directly. Layering basin-specific variations on top of this scheme for certain instances of temporary flaring, which generally should not occur often, is too complex for little to no benefit when considered in conjunction with the requirement that flaring must cease when the issue giving rise to the need to temporary flare is resolved.

Lastly, the record does not support the conclusion that any one basin faces persistent technical barriers that would justify a regional variation to the originally proposed 48-hour or finalized 72-hour temporary flaring limit. Instead, we support an

[99] 89 FR 16887 (March 8, 2024).

approach that allows limited extensions under exigent circumstances, as discussed in section IV.A.1 of this preamble, but maintains a consistent framework across all basins. This ensures fairness, limits emissions, and encourages continued operational innovation in the oil and gas industry.

B. Vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and enclosed combustion devices

The March 2024 Final Rule requires owners and operators to perform NHV sampling for flares and ECD through continuous monitoring of NHV or through periodic testing with sampling demonstrations. As stated in the January 2025 Proposal, industry petitioners stated in their reconsideration petitions that the compliance demonstrations are unnecessary, technically infeasible, and provide a limited timeline for compliance. The petitioners argued that over 99 percent of historical Btu stream data already complies with the prescribed minimum NHV content values (depending on flare type) outlined in the March 2024 Final Rule. Industry petitioners asserted that NHV content is usually a concern when inert gases are added to the process streams, which typically occurs during scheduled situations and is known to the operator of the affected source.

Based on information from these petitions, as well as further information provided by industry, in the January 2025 Proposal the EPA proposed changes to the continuous monitoring requirements and alternative performance test options (sampling demonstration) of NHV for flares and ECD. First, for the continuous monitoring requirement, we proposed to expand the streams that are exempt from monitoring NHV to include unassisted flares and ECD at new sources, and unassisted, air-assisted, and steam-assisted flares and ECD at existing sources. We also proposed to replace the general exemption from NHV monitoring for associated gas for any control device used at "well site affected facilities" with NHV monitoring that is more reflective of industry operations. Additionally, we proposed to require NHV monitoring for streams where inert gases were added and for operational scenarios where NHV is known to decrease (*e.g.*, nitrogen and acid gas removal, glycol dehydration, etc.) in flares and ECD that are subject to the 200 or 300 Btu/scf minimum requirements. The EPA relied on data provided by industry, which showed reduced NHV from the dilution of inlet streams by effluent streams with known high content of inerts, such as those from amine units or produced water tank streams. In the event of stream dilution (for any reason), owners and operators would need to satisfy more robust recordkeeping and reporting requirements. Second, for the alternative performance test (sampling demonstration) requirements, we proposed to allow breaks during weekends and holidays for the March 2024 Final Rule's consecutive 14-day sampling demonstration requirements to account for reasonable operational pauses. We also addressed ambiguity regarding the location of NHV grab sampling methods by specifying in the January 2025 Proposal that samples should be taken upstream of the control device, provided that the sample is representative of the gas being introduced to the control device. Finally, in the January 2025 Proposal the EPA clarified NHV testing must be reported in volumetric units (Btu/scf) instead of specific units (Btu/lb) in order to facilitate consistency in reporting.

The EPA received several comments on the proposed amendments regarding the NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and ECD in the January 2025 Proposal. Highlights of these comments and the EPA's responses are provided, as well as discussion of changes from the January 2025 Proposal as applicable. This preamble does not discuss the EPA's response to any of those comments. The agency's responses are available in the EPA's RTC document (Chapter 4) for the final rule.[100]

1. 60-Day Deadline

In the January 2025 Proposal, the EPA proposed to allow 60 days for owners and operators to conduct the continuous NHV monitoring required by one of the options in 40 CFR 60.5417b(d)(8)(ii)(A) through (D), if the results of the periodic sampling (*i.e.*, three samples every five years) indicate that the NHV is less than 1.2 times the applicable threshold NHV level in the rule. The EPA considers it necessary to specify a timeframe to install and operate the required continuous monitors to provide owners and operators with regulatory certainty for when this must occur. We consider 60 days to be an expedited time schedule for the installation of continuous monitoring systems, but we also consider it a reasonable timeframe for installing the necessary grab sampling systems to automatically collect samples at least once every eight hours as provided in 40 CFR 60.5417b(d)(8)(ii)(D). The proposal would require facilities to collect grab samples every eight hours until such time that a continuous monitor can be installed, and installation of such a system may require more than 60 days. We requested comment on the proposed 60-day compliance provision when a five-year sampling event indicates the vent stream is not sufficiently above the required NHV.

[100] Reconsideration of 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 January 2025 Proposed Rule (90 FR 3734; January 15, 2025). See Docket No. EPA-HQ-OAR-2024-0358.

Comment: One commenter supported the EPA's proposed 60-day deadline to require continuous NHV monitoring after either a periodic sample or a post-process change re-evaluation demonstrates the flare or ECD inlet gas is below the applicable NHV limit.[101] The commenter stated that more deadlines are necessary to provide clear compliance obligations. The commenter also suggested that where a post-NHV demonstration periodic sample is below the applicable NHV limit, the operator must commence continuous NHV monitoring or recomplete the NHV demonstration within 60 days of receiving the analytical results. The commenter suggested that the opportunity to recomplete the NHV demonstration would account for the possibility of errors in sampling or analysis.

Response: The EPA received only supportive comments regarding the proposed clarification of allowing 60 days for implementing the continuous NHV monitoring required by one of the options in 40 CFR 60.5417b(d)(8)(ii)(A) through (D) if the results of the periodic sampling (*i.e.*, three samples every five years) indicate that the NHV is less than 1.2 times the applicable threshold NHV level in the rule. Hence, we are finalizing this particular provision as proposed. Owners and operators could resolve any potential error in sampling or analysis by implementing a continuous NHV monitor within the newly clarified 60-day window.

Moreover, 40 CFR 60.5417b(d)(8)(iii)(E) and 40 CFR 60.5417c(d)(8)(iii)(E) requires that if process operations are revised that could impact (*i.e.*, lower) the NHV of the gas sent to the enclosed combustion device or flare, such as the removal or addition of process equipment, owners and operators must perform a re-evaluation of the NHV of the

[101] Document ID No. EPA-HQ-OAR-2024-0358-0088.

gas stream. The EPA is clarifying that this re-evaluation must be performed within 60 days of the process operations being revised, on those enclosed combustion devices and flares subject to NHV testing.

2. Revisions to Inlet Gas Streams Exempt from Monitoring

Based on information provided by petitioners after the publication of the March 2024 Final Rule regarding NHV characteristics of sample streams, in the January 2025 Proposal the EPA proposed changes to the March 2024 Final Rule that would expand the scope of the exclusion for the NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option so that the following control devices would not be required to make any such demonstration: unassisted flares or ECDs at new sources; and unassisted, air-assisted, or steam-assisted flares or ECDs at existing sources. New data submitted in API and AXPC's joint petition for reconsideration dated April 2024 demonstrated that, for over 22,000 NHV low-pressure (LP) data points, 99.5 percent of those data points showed that the NHV was at least 800 Btu/scf and more than 99.9 percent of those data points showed that the NHV was at least 300 Btu/scf. Notably, these data were consistent across different basins.[102] Data supplied by GPA Midstream in its July 2024 letter supported its prior petition submittals that gas streams in the midstream consist of natural gas and field gas with NHVs greater than 1,000 Btu/scf, with the exception of certain streams in which inert gases or other known low-NHV streams were added.[103] Because these new data further demonstrate that the NHV of the vent gas is consistently well above the 200 or 300 Btu/scf vent gas requirements for these

[102] 99 percent of the data were from five basins: Permian, Anadarko, Gulf Coast (Eagleford), Williston (Bakken), and Powder River. See March 18, 2024, API/AXPC Slides in Docket ID No. EPA-HQ-OAR-2024-0358.

[103] Document ID No. EPA-HQ-OAR-2024-0358-0094.

control devices when inerts are not present, and because there are no combustion zone or dilution parameters for these control devices, the EPA proposed to determine that an expanded exclusion from the monitoring requirements is appropriate.

In the January 2025 Proposal, the EPA did not propose to exclude pressure-, steam-, or air-assisted flares or ECD from the NHV compliance demonstration requirements for new sources. After the January 2025 Proposal, based upon the EPA's solicitation for comment for the sampling requirements for pressure-assisted flares and ECDs at new and existing sources and for air- and steam-assisted flares or ECDs at new sources,[104] in April 2025 API supplemented its comment letter with new high-pressure (HP) stream data (39,000 samples) from 11 basins with over 99.5 percent of these data greater than 800 Btu/scf, which was comparable to that of the LP NHVs previously analyzed in 2024. Again, these were consistent across different basins.[105] For the combined data sets from April 2024 and April 2025, which consisted of over 60,000 data points from both LP and HP gas streams, over 99.5 percent of the data showed NHV contents of at least 800 Btu/scf and over 99.9 percent of the data showed NHV contents of at least 300 Btu/scf.[106] In this combined data set, over 99 percent of the data samples from LP gas streams resulted in a NHV content of greater than 900 Btu/scf and over 95 percent of the data samples from HP gas streams resulted in a NHV content of greater than 900 Btu/scf. Of particular note, while less than 0.5 percent of the total samples yielded NHV contents of 800 Btu/scf or less, these instances were from known scenarios

[104] 90 FR 3748 (January 15, 2025).
[105] 97 percent of the data were from eight basins: Permian, Anadarko, Gulf Coast (Eagleford), Williston (Bakken), Powder River, East Texas, Appalachian, and Arkla (Haynesville). See April 2, 2025, API Slides in Docket ID No. EPA-HQ-OAR-2024-0358.

where inerts were added, namely vent gas streams from nitrogen removal units (NRU), acid gas removal (AGR) system amine regenerator still columns, glycol dehydrator unit reboilers without water removal, compressors in acid gas service, or vent streams containing water or CO_2 used for EOR.

As demonstrated by the July 2024 GPA Midstream data set, the addition of inert gases or streams from amine units or produced water tanks can decrease the NHV content of the gas stream to the point that the NHV thresholds for non-pressure-assisted flares or ECD may not be achieved. In addition to sources of inert streams previously identified in the March 2024 Final Rule (*i.e.*, streams from compressors in acid gas service and streams from EOR facilities), the July 2024 GPA Midstream letter explained that other operating scenarios can result in the addition of low-Btu streams into the vent gas stream, which lowers the overall NHV for the vent stream.

Based upon the information and data provided after the publication of both the March 2024 Final Rule and January 2025 Proposal, which demonstrated that over 99.5 percent of the data (consisting of both LP and HP sources) showed NHV contents of 800 Btu/scf or greater and over 99.9 percent of the data showed NHV contents of 300 Btu/scf or greater, the EPA is expanding the streams that are exempt from monitoring due to high NHV content to include all flare and ECD for both new and existing sources.

We are finalizing that NHV sampling is only required for any new or existing flare or ECD in cases where there are contributions from inerts, and for other miscellaneous scenarios which decrease the NHV content, using the continuous monitoring requirements and alternative performance test (sampling demonstration) options currently prescribed in the NSPS OOOOb and EG OOOOc rules and summarized in section III.B of this preamble.[107] The EPA expects that the operational scenarios described in section IV.B.2.c. of this preamble can be easily validated and documented through the physical presence (or absence) of process equipment, process piping, engineering analysis, or process flow diagrams in order to determine when the owner or operator should monitor the NHV of the stream.

For example, in the case of the acid gas removal (AGR) system amine regenerator still column vent gas, it would be easy to trace process piping to determine whether the vent stream was routed to a dedicated control device or was combined with affected facility vent gas streams. Similarly, for the glycol dehydration unit reboiler vent gas, the lack of a process condenser would indicate that higher water content (and lower Btu) reboiler vent gas streams were combined with affected facility vent gas streams. The use of nitrogen as a blanket gas can be readily determined through the presence of nitrogen storage, supply systems, and process piping. Finally, we expect that storage tanks with water content high enough to depress overall NHVs typically would not meet the applicability thresholds of the rule and would not be combined with other vent streams routed to a flare or ECD. However, when gas streams from produced water tanks are vented to controls, vent lines from these tanks can be traced to identify sources that require monitoring or sampling.

Since we proposed to remove the general monitoring exemption for when the only inlet gas stream to the flare or ECD is associated gas from a well affected facility, we also directly resolved one of the issues raised in the May 2024 EIP et al. petition. We consider the data submitted by the industry petitioners to support the proposed exclusion from

[107] See 40 CFR 60.5417b(d)(8) and 40 CFR 60.5417c(d)(8).

monitoring for flares and ECD subject to a vent gas NHV requirement of 200 or 300 Btu/scf (and not subject to NHV_{cz} and NHV_{dil} requirement) when no inerts are present because the results were consistently much higher than these levels. The May 2024 EIP et al. petition also contended that the EPA did not support its conclusion in the March 2024 Final Rule that initial assessments of flares and other control devices, in lieu of continuous monitoring, can capture the variability of NHV in the oil and gas sector. The EPA has concluded that the data submitted by the industry petitioners supports the conclusion that the NHV demonstrations required for pressure-, air-, and steam-assisted control devices are adequate to show that the NHV from those demonstrations is above the required thresholds specified by the rule and that continuous monitoring is not needed. When inerts are added intermittently or process operations change in ways that that may lower the NHV, the proposed standards require a re-demonstration with a new 14-day sampling effort.[108] The re-demonstration would consider the variability associated with these operations and determine a reasonable lower-range value to use in compliance assessments. As such, we proposed that the sampling requirements, with the revisions proposed and now being finalized, are robust and sufficient to demonstrate that continuous monitoring is not needed when the NHV of the gas stream being controlled is sufficiently high, when considering the range of vent gas and assist gas flow rates, to meet the required standards.

While we previously excluded monitoring for associated gas from the NHV compliance demonstration requirements, some petitioners have identified instances where the NHV for associated gas streams could be compromised. Specifically, the use of water

[108] 800 Btu/scf for pressure-assisted flares and 270 Btu/scf for steam- and air-assisted flares.

or CO_2 flooding for EOR could introduce significant inerts as part of the associated gas produced and thereby lower the NHV of the associated gas. We found the information presented by the petitioners compelling and therefore proposed to conclude that the March 2024 Final Rule's exclusion of associated gas from the NHV compliance demonstration requirements is overly broad. Because the definition of associated gas in the March 2024 Final Rule specifically excludes these inert gases that may be released with the natural gas during the initial stage of separation after the wellhead, there are cases where associated gas can have high levels of inerts and low NHV. Therefore, the EPA proposed to remove this exclusion for associated gas in its entirety and also requested comment on the proposed removal of the associated gas monitoring exemption, as well as any additional miscellaneous operating scenarios that can compromise the NHV for associated gas streams as well as all flare types and ECD.

a. Exemptions from NHV monitoring

Comment: Several commenters requested exemptions from all NHV monitoring. One commenter stated that the EPA's proposal to reconsider the streams that are exempt from monitoring due to high NHV content for flares or ECD at new and existing sources would allow for additional flexibility and compliance options for regulated entities.[109] The same commenter asserted that extending the exemption from NHV sampling/monitoring requirements for affected facilities under NSPS OOOOb and EG OOOOc to streams other than associated gas to include other equipment with consistently high NHV vent streams would allow for many upstream facilities to demonstrate effective control of VOCs and methane while providing flexibility and reducing the

[109] Document ID No. EPA-HQ-OAR-2024-0358-0085.

compliance burden associated with continuous monitoring. The commenter suggested that the EPA consider expanding the streams exempt from monitoring for unassisted flares or ECD at new sources, and unassisted, air-assisted, and steam-assisted flares or ECD at existing sources to create consistency between requirements for new sources and existing sources. The commenter added that this would provide flexibility and lessen the compliance burden associated with applying the monitoring standards to affected facilities under NSPS OOOOb and EG OOOOc.

Another commenter urged the EPA to remove all NHV monitoring requirements for all upstream sector flares and ECD in both the NSPS OOOOb and EG OOOOc, regardless of whether inert gas is added, and to remove the NHV standards which prompt such monitoring.[110] The commenter stated that operators in the Williston Basin already collect and analyze data throughout the well's lifecycle for permitting, compliance, and reporting purposes and that midstream companies sample associated gas routinely (often monthly, including composition and NHV) to handle custody transfer payments. The commenter stated that these operators sample and analyze using established standards and that therefore the March 2024 Final Rule NHV monitoring requirements are redundant.

The same commenter added that the manufacturer of control devices specifies the minimum or required range of the NHV for the inlet gas which is necessary to operate the control device effectively. Regarding lower-Btu gas, the commenter stated that flare and ECD technology exists (and continues to evolve) which can ensure stable combustion at lower heating values and that imposing rigid NHV monitoring requirements can limit

[110] Document ID No. EPA-HQ-OAR-2024-0358-0091.

innovation. The commenter stated that upstream sector flares and ECD have consistently been designed and tested to ensure high combustion efficiency (destruction removal efficiency (DRE) exceeding 99 percent) without the need for complex NHV monitoring typically required for petroleum refinery flares. The commenter pointed to comments in the May 2024 API and AXPC petition which highlighted fundamental differences between upstream sector flares and petroleum refinery flares regarding NHV requirements. The commenter explained that upstream flares are not designed with NHV requirements because they operate under non-steady state conditions, with a more consistent gas composition, including NHV. In contrast, the commenter noted that the Refinery MACT includes NHV requirements and operates under steady state conditions with varying gas composition (which can include different NHV contents). The commenter stated that upstream flares are specifically designed to maintain high combustion efficiency even in non-steady state conditions due to the limited variability of the vent gas composition and relatively few gas streams routed to the control device.

Several commenters requested that NHV continuous monitoring only apply in situations where inert gases are introduced into the vent gas stream.[111] Two of the commenters[112] referred to data[113] previously provided to the EPA which they state demonstrates that oil and gas facilities consistently exceed the minimum NHV limits, except for known scenarios.

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[111] Document ID No. EPA-HQ-OAR-2024-0358-0083, -0088, -0090, -0092, -0093, -0094, -0095.

[112] Document ID No. EPA-HQ-OAR-2024-0358-0092, -0095.

[113] See, *e.g.*, Letter from American Petroleum Institute and American Exploration & Production Council, to Michael S. Regan, US EPA Administrator, Provisions Creating Immediate Compliance and Implementation Issues EPA's Final Rule "Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 5, EPA-HQ-OAR-2024-0358-0009 (April 5, 2024).

One commenter requested that the EPA not require NHV monitoring unless inert gases are added or for other miscellaneous scenarios which decrease vent gas NHV regardless of type of control device.[114] The commenter stated that, in previous comments submitted to the EPA, they provided data that shows the vent gas NHV is typically well above 900 Btu/scf, and therefore the NHV monitoring requirements are unnecessary except in specific operations which introduce inert gases into the vent gas stream. The commenter provided that the previous data set represented LP vent gas streams and included over 22,000 data points from 18 operators covering approximately 4,200 sites, including well sites, central production facilities, and compressor stations. A second data set for HP vent gas streams, collected in the same operator survey in coordination with AXPC, is included in the commenter's letter and represents an additional 39,000 data points from 12 operators covering approximately 22,100 sites, primarily from well sites and central production facilities. The commenter concluded that NHV monitoring should only be required when inert gases are added or for other miscellaneous scenarios which decrease vent gas NHV regardless of type of control device.

Another commenter also urged the EPA to exempt NHV monitoring for flares and ECD that control associated gas from any oil well (not just well affected facilities under NSPS OOOOb or well designated facilities under EG OOOOc).[115] The commenter explained that the composition of associated gas does not change due to regulatory applicability, and the current associated gas exemption arbitrarily limits the scope of the exemption.

[114] Document ID No. EPA-HQ-OAR-2024-0358-0083.
[115] Document ID No. EPA-HQ-OAR-2024-0358-0088.

Lastly, a commenter recommended that the EPA allow the NHV monitoring exemption to apply to pressure-assisted control devices.[116] The commenter referenced the January 2025 Proposal in which the EPA states that because the NHV of methane (896 Btu/scf) is not significantly higher than the required minimum NHV of 800 Btu/scf for pressure-assisted flares and ECD, the Agency will continue to require either continuous monitoring or alternative performance testing (14-day NHV test) for these devices. The commenter urged the EPA to reconsider this approach, which they say is not supported by the record and is contrary to common sense. The commenter further provided that the EPA further stated in the January 2025 Proposal that "…we find that it is much easier for the NHV in the vent gas samples from these control devices to decrease and approach the 800 Btu/scf NHV threshold…" According to the commenter, this reason does not support costly continuous monitoring.

Conversely, two commenters opposed the EPA's proposal to exempt flares and ECD from NHV monitoring. One of the commenters agreed with the EPA's proposal to require certain flares and other control devices controlling emissions from associated gas to monitor or sample for NHV. According to the commenter, the EPA must do so given that some petitioners have identified instances where the NHV for associated gas streams could be compromised, such as in water or CO_2 flooding which can introduce a large amount of inerts as part of the associated gas produced. However, the commenter disagreed with the EPA's proposal to require this monitoring or sampling only for pressure-assisted flares and other controls at new and existing sources and air- and steam-assisted flares and other controls at new sources. The commenter stated that the EPA

[116] Document ID No. EPA-HQ-OAR-2024-0358-0094.

must also require NHV monitoring or sampling for unassisted flares at new and existing sources and air- and steam-assisted flares at existing sources. The commenter stated that the EPA has failed to establish that the NHV of gases sent to flares and other controls, including those where no inert gases are added and nothing else decreases the NHV content of the inlet stream gas, will always be above the March 2024 Final Rule's NHV limits. According to the commenter, this means that the EPA cannot rationally justify a complete exemption from NHV monitoring and sampling.

The other commenter strongly opposed the EPA's proposal to remove NHV monitoring requirements for all new unassisted flares and ECD (with limited exceptions due to inerts) and for existing air-assisted and steam-assisted flares and ECD and asserted that the EPA has changed its position without adequate justification.[117] The commenter urged the EPA to maintain NHV monitoring requirements for all unassisted flares and ECD.

The same commenter referenced the EPA's justification for its proposed exemption from all NHV monitoring for unassisted flares and ECD, which cited new data[118] provided by API, AXPC, and GPA Midstream that the EPA claims "appear to demonstrate that the NHV of the vent gas is consistently well above the 200 or 300 Btu/scf vent gas requirements for these control devices when inerts are not present, and because there are no combustion zone or dilution parameters for these control devices."[119] The commenter suggested that several deficiencies in the data cut strongly

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[117] Document ID No. EPA-HQ-OAR-2024-0358-0096.
[118] See API-AXPC NHV Survey Results v1.0 at *https://www.regulations.gov/document/EPA-HQ-OAR-2024-0358-0044*; July 31, 2024 Email from GPA (Response for additional information) at *https://www.regulations.gov/document/EPA-HQ-OAR-2024-0358-0039*.
[119] See 90 FR 3747 (January 15, 2025).

against the EPA's decision to exempt all unassisted flares and ECD from the monitoring requirements. The commenter disagreed that the Temporary Flaring Survey contains enough information to ensure the NHV figures represent the entire vent gas stream going to the flare or ECD. The commenter contended that because the data sets do not specify that all samples were taken after all vent streams were combined, it is inappropriate for the EPA to make a sweeping exemption based solely on the data presented.

The same commenter also supported the proposed removal of the exemption for associated gas waste streams, which they state is supported by the record. The commenter agreed with the EPA's assessment of information, provided that the NHV of associated gas does not always exceed the minimum limits as the EPA expected it would when it finalized the exemption in the March 2024 Final Rule. Further, the commenter agreed that the information provided demonstrates that associated gas can be combined with inerts, which in turn may reduce the NHV below the required minimum thresholds. The commenter urged the EPA to expand the inclusion of NHV monitoring for unassisted flares and ECD where the only vent stream is associated gas for these reasons and for the reasons discussed in other remarks by the commenter which address the EPA's proposed exemption of unassisted flares and ECD from all NHV monitoring.

Response: The EPA received numerous comments regarding the vent gas NHV continuous monitoring requirements and alternative performance test (sampling demonstration) option for flares and ECD discussed in the January 2025 Proposal.

In general, most commenters were in favor of the EPA's proposal to expand the streams to include unassisted flares or ECD at new sources and to include unassisted, air-assisted, and steam-assisted flares or ECD at existing sources, and to only require NHV monitoring for streams where inert gases were added or in the event of operational scenarios where NHV is known to decrease. However, most commenters disagreed with the EPA's proposal to continue to require the NHV monitoring that is currently required for all pressure-, air-, and steam-assisted flares or ECD at new sources and for pressure-assisted flares or ECD at existing sources.

To support this argument, as discussed in section IV.B.2 of this preamble, in April 2025 API provided new HP stream data (39,000 samples) from 11 basins with over 99.5 percent of these data greater than 800 Btu/scf, which was comparable to that of the LP NHV previously analyzed in 2024. For the combined data sets from April 2024 and April 2025, which consisted of over 60,000 total combined data points from both LP and HP gas streams, over 99.5 percent of the data showed NHV contents of at least 800 Btu/scf and over 99.9 percent of the data showed NHV contents of at least 300 Btu/scf. In this combined data set, over 99 percent of the data samples from LP gas streams resulted in an NHV content of greater than 900 Btu/scf and over 95 percent of the data samples from HP gas streams resulted in an NHV content of greater than 900 Btu/scf. The EPA reviewed the "Sample Description/Source" field in both the LP and HP data sets and concluded that the sources for which NHVs were determined are representative of gases that may be controlled by a flare or ECD. In turn, the EPA found this additional data form a robust, reliable, and representative data set to support a compelling argument to include both the LP and HP data (which comprises data from unassisted, air-assisted, and steam-assisted flares and ECD) as its justification to expand the streams that are exempt from monitoring (due to typically high NHV contents, on average) to include all flare and ECD for both new and existing sources.[120]

While the EPA recognizes that in some instances sources may not achieve the applicable and prescribed NHV content values in NSPS OOOOb and EG OOOOc, industry commenters have presented sufficient information to conclude that these instances occur where inert gases are added or under other miscellaneous scenarios that decrease the NHV content of the inlet stream gas to all flare and ECD for both new and existing sources. As such, and as proposed, the EPA is requiring an NHV demonstration where inert gases are added, or for other miscellaneous scenarios that decrease the NHV content of the inlet stream gas for all flare and ECD for both new and existing sources. The EPA is also finalizing recordkeeping and reporting requirements to indicate whether the flare or ECD receives (or does not receive) inert gases or other streams that may lower the NHV of the combined stream, and, if so, a description of the operating scenario(s) that may lower the NHV of the combined stream through the introduction of those inert gases or other streams. Moreover, the EPA is also clarifying that when a required NHV demonstration is performed, the samples must be taken during the period with the lowest expected NHV (*i.e.*, the period with the highest percentage of inerts).

Regarding the comments opposing the January 2025 Proposal in this respect, one commenter[121] asserted that the EPA changed its position without adequate justification and lacked sufficient evidence to support such an exemption. The EPA disagrees. The combined data set described earlier in this response presented tens of thousands of data

[120] As summarized in footnotes 106 and 108, 99 percent of the LP data were from five basins and 97 percent of the HP data were from eight basins, which geographically represent the primary basins located throughout the United States.
[121] Document ID No. EPA-HQ-OAR-2024-0358-0096.

points (*i.e.*, fuel analysis samples for NHV content) for consideration and analysis. Moreover, as the EPA has already discussed in this preamble, it will not completely exempt flares and ECD as a whole from all NHV monitoring. That is, the EPA will still require an NHV demonstration where inert gases are added, and for other miscellaneous scenarios that decrease the NHV content of the inlet stream gas for all flare and ECDs for both new and existing sources. Given the EPA received over 60,000 data points for consideration and analysis, which were spread over the primary basins that geographically represent the oil and gas industry, with over 99.5 percent of the results being above the NHV thresholds currently prescribed by the NSPS OOOOb and EG OOOOc rules, the EPA considers the data submitted to be sufficiently reliable and persuasive to finalize the NHV exemptions included in this action. Moreover, by providing these NHV exemptions, the EPA believes that the industry will be in a better position to redirect and focus its cost expenditures, manpower, and emissions reduction efforts on the issues of most concern, such as equipment inspections, maintenance, and leak prevention measures.

Finally, the EPA is finalizing its proposal to replace the general exemption from NHV monitoring for associated gas for any control device used at "well site affected facilities" with NHV monitoring that is more reflective of industry operations. However, consistent with the finalized rule requirements for all flare and ECDs, associated gas streams will still be subject to NHV monitoring where inert gases are added, or in the event of operational scenarios where NHV is known to decrease.

b. Distinction of "new" and "existing" flares and enclosed combustion devices

Comment: One commenter expressed disagreement with the EPA's distinction between "new" and "existing" flares and ECD, especially as it relates to proposed exemptions from NHV monitoring because, in practice, this effectively exempts all flares and ECD from NHV monitoring unless the flare or ECD is brand new.[122] According to the commenter, that means that only new affected facilities using new flares and ECD would be required to comply with the NHV monitoring requirements, and any modified or reconstructed affected facilities (and existing designated facilities) would be exempt from these provisions. The commenter believed that the EPA has not explained or justified this type of distinction related to flares and ECD nor how these exemptions for "existing" flares address the concerns about "pervasive issues with combustion sources."[123]

The commenter further asserted that control devices, including flares and ECD, are not by themselves "new" or "existing" sources under the NSPS or EG. Instead, these control devices are used to meet certain emission reduction standards for "new" affected facilities or "existing" designated facilities. Therefore, the commenter contended that the EPA must clearly define how it distinguishes the terms "new" and "existing" for purposes of the exemptions proposed if it moves forward with finalizing any exemptions from NHV monitoring.

Response: For the purposes of this final rule, "new" sources are designated as NSPS OOOOb sources, which are crude oil and natural gas facilities for which construction, modification, or reconstruction commenced after December 6, 2022, and

[122] Document ID No. EPA-HQ-OAR-2024-0358-0096.
[123] 87 FR 74793 (December 6, 2022).

"existing" sources are designated as EG OOOOc sources, which are crude oil and natural gas facilities for which construction, modification, or reconstruction commenced on or before December 6, 2022.

Based on the revisions to both NSPS OOOOb (*i.e.*, new, modified, and reconstructed sources) and EG OOOOc (*i.e.*, existing sources) as a result of this final rule, NSPS OOOOb sources and EG OOOOc sources will now have identical NHV sampling requirements and exemption qualifiers, with the exception of the NHV_{cz} and NHV_{dil} requirements that will only apply to NSPS OOOOb sources, as described in section IV.B.5 of this preamble. Hence, any distinction between "new" and "existing" sources would no longer apply in this context as it relates to the exemptions from NHV monitoring, since both "new" and "existing" sources will now have the same NHV sampling requirements and categorical exemptions with the finalization of this rulemaking.

c. Inert gas and other vent gas stream example scenarios

Comment: Numerous commenters provided recommendations, clarifications, and suggestions "where inert gas or other vent gas streams which may lower the NHV of the combined stream are added." One commenter cited the proposed regulatory text at 40 CFR 60.5417b(d)(8)(ii) to describe the inert gas added scenarios under which NHV continuous monitoring or alternative sampling demonstration would be required, noting that the corresponding language was proposed for EG OOOOc.[124] The commenter provided the following recommendations and supporting rationale for both subparts (NSPS OOOOb and EG OOOOc): (1) remove "vent streams from storage vessel with

[124] Document ID No. EPA-HQ-OAR-2024-0358-0083.

high water content," (2) "vent streams from glycol dehydrator unit reboilers" should be revised to "vent streams from glycol dehydrator unit reboilers without water removal" and (3) "vent streams from enhanced oil recovery facilities" should be revised to "vent stream containing water or CO_2 used for enhanced oil recovery."

The commenter stated that the EPA's intent was to require NHV monitoring when the higher water content from a storage vessel could lower the vent gas NHV below the applicable minimum, but the proposed regulatory language could be interpreted as any produced water tank. The commenter noted that the EPA cites GPA Midstream's comment letter as the basis for this example, though GPA Midstream's letter states that even in these cases, the NHV remained above the applicable limit.[125] The commenter contended that the LP NHV dataset also supports removing "storage vessel with high water content" since all data points from produced water tanks were greater than 300 Btu/scf, which meets the minimum vent gas NHV requirement for unassisted, steam-assisted, and air-assisted control devices. While vent streams from produced water tanks can be lower than 900 Btu/scf in certain scenarios, the commenter stated that they are not typically routed to pressure-assisted control devices (minimum vent gas NHV of 800 Btu/scf), since produced water tanks operate at near atmospheric pressure.

The commenter also requested that "[v]ent streams from glycol dehydrator unit reboilers" be revised to "vent streams from glycol dehydrator unit reboilers without water removal", to be consistent with the preamble. The commenter explained that vent streams from glycol dehydrator unit reboilers have higher water content which lowers the NHV,

[125] GPA Midstream – EPA 06/24/24 Meeting Follow-Up. Re: Response to EPA Request for Additional Information Regarding OOOOb GPA Midstream Net Heating Value Case Scenarios and Data. (Attachment Summarizing NHV Data Included).

but they are typically routed through a condenser or other similar equipment to remove water before being routed to combustion control. According to the commenter, the Agency should only require NHV monitoring in cases where the glycol dehydrator unit reboiler does not have water removal.

Finally, the commenter requested that "[v]ent streams from enhanced oil recovery facilities" be revised to "vent stream containing water or CO_2 used for enhanced oil recovery" to clarify that only vent streams that contain the inert gas involved in EOR, not any vent stream at an EOR site, should require NHV monitoring. According to the commenter, based on process knowledge, operators are able to identify which vents streams at an EOR site contain the inert gas used in EOR and therefore have lower NHV and should be subject to NHV monitoring.

Another commenter agreed that the universe of low-NHV streams identified in the proposal encompasses the scenarios of which they are aware, except the commenter is unclear what the EPA means by "vent streams from storage vessels with high water content."[126] The commenter explained that the proposed language may include crude oil or condensate tanks that share a closed vent system and control device with produced water tanks. The commenter stated that the data they provided includes such tanks systems and shows that low-NHV is not an issue in these systems, given the relatively high NHV of the hydrocarbon components of storage tank vapors. The commenter requested that the EPA not include these storage tank systems in the list of low-NHV scenarios.

[126] Document ID No. EPA-HQ-OAR-2024-0358-0088.

Moreover, the commenter asserted that methane, the lightest hydrocarbon organic molecule in process streams at oil and gas facilities, is already above the minimum NHV required for these pressure-assisted devices. Therefore, when a process stream includes any quantities of heavier hydrocarbons, the stream will have a higher heat content and be even further above the minimum NHV requirement. The commenter contended that the EPA's assertion that "it is easier" for the streams going to these devices to experience a decrease in NHV is not based on direct or empirical evidence in the rulemaking record. According to the commenter, if inert gases are not added to the hydrocarbon process stream sent to the control device, the NHV will meet the requirements at all times. As with the proposed requirements for non-assisted flares and ECD, the commenter stated that pressure-assisted devices should be assumed to meet minimum NHV requirements. As such, the commenter suggested that the EPA treat pressure-assisted devices in the same manner as non-assisted flares and ECD and "require NHV monitoring only in cases where inert gases are added, or for other miscellaneous scenarios which decrease the NHV content of the inlet stream gas to the enclosed combustion device or flare."

The same commenter also stated that infrequent nitrogen purges should not prevent a flare from qualifying for the NHV testing exemption. The commenter explained that many gas processing facilities within the industry use nitrogen purging during maintenance procedures to displace air or other gases within a system and create an inert environment by removing oxygen and other potentially reactive components which is crucial for safety, preventing unwanted chemical reactions within pipelines and equipment, and reducing emissions by avoiding potential leaks. The commenter also explained that facilities typically perform nitrogen purging no more than one to three times a year and these purges are small in volume relative to the overall flow going to a flare or ECD. Thus, the commenter reported that they do not expect nitrogen purging to have an impact significant enough to lower the NHV to levels below the compliance limits.

The same commenter additionally suggested that the EPA allow the NHV monitoring exemption when intermittent nitrogen purging occurs in volumes that will not significantly impact the NHV of the total gas stream going to the flare. The commenter stated that the EPA should include an option to demonstrate compliance using site-specific data and process knowledge, such as nitrogen purge volumes and total volume sent to the control device, in the rule language to allow the owner/operator to continue using the NHV monitoring exemption by documenting that intermittent nitrogen purging did not result in the NHV of the total gas stream going to the control device decreasing below the compliance limits.

Conversely, a commenter agreed with the EPA's proposal to not exclude pressure-assisted flares and ECD from NHV demonstration requirements.[127] The commenter asserted that this is the only lawful and rational approach given the Agency's prior findings that the required minimum NHV of 800 Btu/scf for pressure-assisted control devices is not significantly higher than the NHV of methane, that sources that contain primarily methane would not require much dilution from inert components to be below the 800 Btu/scf NHV threshold, and that, while data provided by petitioners indicated that the majority of samples had NHVs above 800 Btu/scf, it is much easier for

[127] Document ID No. EPA-HQ-OAR-2024-0358-0086.

the NHV in the vent gas samples from these control devices to decrease and approach the 800 Btu/scf NHV threshold.

Response: The EPA appreciates the suggestions and clarifications from the commenters to further expand upon the particular “miscellaneous scenarios” that could decrease the NHV content of the of the inlet stream gas to all flare and ECDs for both new and existing sources. Based upon the received comments, as well as those scenarios already included in the January 2025 Proposal, the EPA considers the following miscellaneous operating scenarios as those that could potentially decrease the NHV content of a given inlet stream, and which therefore will not be exempted from the NHV sampling requirements under NSPS OOOOb and EG OOOOc for all flare and ECDs for both new and existing sources, where applicable:

1. Combining AGR system amine regenerator still column vent gas with affected facility vent gas streams – AGR amine regenerator still column vent gases typically are routed to an individual control device due to the low flow rate, low pressure, and corrosive nature of the vent stream, and that the low NHV of the stream typically requires supplemental gas for proper control device operation. However, it is possible to combine the still column vent gas with other vent gas streams, which would lower the NHV of the combined stream, primarily due to the high CO_2 content of the still column vent gas.
2. Combining glycol dehydration unit reboiler vent gas with affected facility vent gas streams without water removal – typically, glycol dehydration unit reboiler vent gas is routed through a condenser to remove liquids (including VOC and water vapor) and then routed to a process or control device.

However, it is possible to combine the glycol dehydration unit reboiler gas, without routing through a condenser, with other vent gases routed to common control. The high water content of the reboiler vent gas stream could lower the NHV of the combined vent gas streams.

3. Use of inert gases and entrainment in affected facility vent gas streams – midstream operations usually do not employ the use of inert gases such as nitrogen because if a blanket gas is needed, its midstream operations use natural gas as it is readily available and compatible with control devices due to the high NHV. In instances where an inert gas such as nitrogen is used as a blanket gas, this could cause lower NHV of the vent gas stream.
4. High water content in vent gas streams from storage vessels – midstream operations employ the use of storage vessels for storing hydrocarbons and produced water (*i.e.*, produced water tanks), which typically have NHVs well above the minimum thresholds required by the March 2024 Final Rule. However, it is possible that some production areas could have higher water content in the vent stream coming from the storage vessels, which would lower the NHV. In these cases, the high water content would increase the probability that the storage vessel emissions thresholds for applicability would not be exceeded. The EPA also clarifies that this scenario pertains to a higher water content from a storage vessel that could lower the NHV below the applicable minimum value, and not "any produced water tank." 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.

5. Compressors in acid gas service – also known as sour gas service, these compressors are used to compress gases containing H_2S and CO_2 for various applications, including injection into underground disposal wells, which are in turn used for natural gas processing and the disposal of acid gas components.
6. Sites in fields with vent streams containing water or CO_2 flooding used for EOR.
7. Flares at gas plants that receive acid gas from sweetening units.
8. NRUs – NRUs in the oil and gas industry are used for separating nitrogen from natural gas streams, improving the heating value and marketability of the gas, and meeting pipeline specifications. This is often achieved using cryogenic distillation. However, during the NRU process, nitrogen dilutes the NHV content of the natural gas, making it less efficient.

d. Flare tip maximum velocity limits

In the January 2025 Proposal, the EPA proposed revisions to 40 CFR 60.5417b(d)(8)(iv), which includes requirements for the usage of one-time assessments in lieu of installing vent gas flow monitors and, in the case of assisted flares, assist gas flow monitors if certain provisions are met. In the March 2024 Final Rule, while we finalized provisions requiring owners and operators of unassisted flares to conduct an initial determination to ensure the flare tip velocity falls within limits under worst-case flow provisions, we did not finalize similar “initial determination” requirements for air-assisted flares, even though the velocity limits apply. Therefore, we proposed to add this maximum velocity assessment to the existing provisions in 40 CFR 60.5417b(d)(8)(iv)(D) and (E) for air-assisted flares. This provision is not applicable to ECD. In reviewing these provisions, we also noted that there was no corresponding provision for steam-assisted flares or ECD. This was an oversight in the March 2024 Final Rule, and we proposed new provisions at 40 CFR 60.5417b(d)(8)(iv)(F) similar to those for air-assisted devices that are specific to steam-assisted flares or ECD. These revisions are not needed in EG OOOOc because these provisions are specific to evaluations for flares complying with an NHV_{cz} or NHV_{dil} parameter. The EPA solicited comment on these proposed provisions to ensure compliance with the velocity operating limit and whether, for those devices that have conducted NHV demonstrations, the velocity limit used in the assessment should be based on the allowable velocity at the lowest NHV result from the demonstration rather than being based on the default of 18.3 meters/second (60 feet/second).

Comment: For air-assisted flares, several commenters believed that the proposed text for alternatives to inlet flow monitoring at 40 CFR 60.5417(d)(8)(iv) references incorrect flare tip maximum exit velocity limits. One commenter[128] asserted that the maximum flare tip velocity limit should be based on the methodology in 40 CFR 60.18 rather than a default limit of 60 feet/second for alternative flow monitoring demonstrations. The commenter stated that NSPS OOOOb at 40 CFR 60.5412b(a)(3)(v) states that flares (except for pressure-assisted flares) must comply with the maximum flare tip velocity limits in 40 CFR 60.18. The commenter stated that the rule, however, then uses a default maximum tip velocity of 18.3 meters/second (60 feet/second) for the

[128] Document ID No. EPA-HQ-OAR-2024-0358-0083.

alternative flow monitoring demonstration requirements at 40 CFR 60.5417b(d)(8)(iv)(B)(1) for unassisted devices. The commenter stated that the EPA is proposing to add similar regulatory text for air- and steam-assisted flares at 40 CFR 60.5417b(d)(8)(iv)(D)(3), (E)(3), and (F)(3) in this rulemaking. The commenter indicated that most gas streams in upstream and midstream operations have sufficient minimum NHV to allow maximum tip velocities greater than 60 feet/second in accordance with 40 CFR 60.18.

The commenter further added that they do not believe it was the EPA's intent that when the backpressure regulator is used in lieu of (*i.e.*, as an alternate to) flow monitoring, the flare tip velocity must be maintained below 60 feet/second, as 40 CFR 60.18 allows for higher tip velocities based on NHV. The commenter suggested that the EPA should therefore update the alternative flow monitoring demonstrations requirements to reference the applicable 40 CFR 60.18 requirements for maximum tip velocity rather than use a default of 60 feet/second.

Two commenters explained that while the proposed text requires that the maximum flow rate to the flare should not exceed 18.3 meter/second, this is not the 40 CFR 60.18 standard that applies to air-assisted flares.[129] Instead, the commenter stated, 40 CFR 60.18(c)(5) requires that air-assisted flares "be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the methods specified in [40 CFR 60.18(f)(6)]." According to the commenter, using V_{max} provides a much larger acceptable flare operating range without compromising flare performance. The commenter stated that if the EPA does not make this change, the scope of flares subject

[129] Document ID Nos. EPA-HQ-OAR-2024-0358-0088, -0092.

to this alternative could be significantly reduced, and, in turn, the EPA's assumption that "few facilities will have to install continuous monitoring systems" would be incorrect. Another commenter also explained that the NSPS OOOOb proposal text and the March 2024 Final Rule both apply the same maximum exit velocity of 18.3 meter/second to steam-assisted and unassisted flares.[130] The commenter assumed that the EPA derived this limit from 40 CFR 60.18(c)(4)(i), but explained that while they agree that this limit does apply to certain steam-assisted and unassisted flares, multiple limits could apply, depending on the operating conditions. Similarly, another commenter noted that the January 2025 Proposal did not reference or incorporate all of the applicable 40 CFR 60.18(c) provisions for unassisted flares.[131] The commenter requested that, for unassisted flares, the EPA allow operators to demonstrate compliance with any of the options in 40 CFR 60.18(c)(3)(i) or (4). For these reasons, commenters requested that the EPA provide the full suite of options under 40 CFR 60.18 for flare tip exit velocity limits.

One commenter also stated that the corresponding edits should also be made to the EG OOOOc alternative flow monitoring demonstration requirements in 40 CFR 60.5417c(d)(8)(iv)(B)(1).[132]

Conversely, one commenter agreed with the EPA's previous recognition that 40 CFR 60.18(d) mandates the Agency to establish monitoring for 40 CFR 60.18(c)(3)(ii)'s NHV limits, which the March 2024 Final Rule adopted for unassisted flares.[133,134] The commenter contended that the EPA's proposed exemption from NHV monitoring violates

[130] Document ID No. EPA-HQ-OAR-2024-0358-0088.
[131] Document ID No. EPA-HQ-OAR-2024-0358-0092.
[132] Document ID No. EPA-HQ-OAR-2024-0358-0083.
[133] Document ID No. EPA-HQ-OAR-2024-0358-0086.
[134] 87 FR 74702 and 74792-93 (December 6, 2022).

40 CFR 60.18(d), which requires each applicable subpart to include provisions stating how owners or operators using flares will monitor them.

Response: We agree with the commenters that 40 CFR 60.18(c) and (f) provide alternative values for the maximum flare tip velocity, V_{max}. We included the 18.3 meters/second (60 feet/second) value for V_{max} because it was the lowest V_{max} value for the 40 CFR 60.18 alternatives and because there were exemptions from NHV monitoring, so data may not be available to assess V_{max} using the alternatives in 40 CFR 60.18. However, the exemptions from NHV monitoring are based on data supplied by petitioners and commenters, which show that NHV of gases generated at oil and gas facilities are consistently above 800 Btu/scf, provided no inert gases are added. At these high NHV vent gas values, V_{max} values of up to 122 meters/second (400 feet/second) are allowed. As such, we agree with the commenters that the proposed 18.3 meters/second (60 feet/second) V_{max} limits unnecessarily impose more stringent limitations when the engineering assessment is used to demonstrate compliance. We agree that this could require the installation of flow meters on many flares where, if more accurate estimates of NHV were allowed, the flare could have demonstrated continuous compliance with the V_{max} limit based on the engineering calculations.

We also note that we allow the use of "…the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare…" when conducting engineering assessments used to demonstrate compliance with the NHV_{cz} or NHV_{dil} requirements (see 40 CFR 60.5417b(d)(8)(iv)(D)(*2*) and (E)(*2*)). Because we allow the use of previous sampling results or process knowledge for determining minimum NHV in these engineering assessments, we find it is more consistent and reasonable to allow these same provisions in the V_{max} engineering calculations. Therefore, we are revising the engineering assessments related to maximum flare tip velocities to determine V_{max} as specified in the applicable provisions in 40 CFR 60.18(c) and (f) of this chapter using the minimum expected value of the NHV of the inlet gas to the flare or ECD based on previous sampling results or process knowledge of the streams sent to the flare or ECD.

Regarding the 40 CFR 60.18(d) requirement that each applicable subpart include provisions stating how owners or operators using flares will monitor these control devices, the EPA disagrees that these finalized exemptions from the NHV requirements violate 40 CFR 60.18(d), since this final rule is only revising and clarifying the monitoring alternatives in the existing NSPS OOOOb and EG OOOOc rules, rather than removing the monitoring provisions altogether, which will continue to be prescribed and required by 40 CFR 60.5417b and 40 CFR 60.5417c, respectively.

3. Sampling Location and Duration of Alternative Performance Test

In the January 2025 Proposal, the EPA reconsidered the requirements in the March 2024 Final Rule regarding the sampling duration for the alternative performance test (sampling demonstration) option for the NHV compliance demonstration and proposed to allow for shorter sampling times when it is technically infeasible to collect a grab sample for a minimum of one hour. While the March 2024 Final Rule included provisions for sampling periods of longer than 14 days (where needed) to collect a total of 28 samples, and the general provisions in 40 CFR 60.8(b)(5) also allow for “shorter sampling times and smaller sample volumes when necessitated by process variables or other factors," we found compelling the petitioner's arguments and newly presented supporting information regarding the potential instances of intermittent flow of gas streams, which makes sampling for one hour technically infeasible in those cases (*e.g.*, intermittent flow from sources with low pressure). As such, we found it appropriate to propose additional flexibility in the January 2025 Proposal to fully address these intermittent flow situations. Therefore, we proposed that sampling must be conducted for a minimum of one hour, when technically feasible. When it is not technically feasible to collect the sample for a minimum of one hour, the owner or operator should collect the sample for as long as possible, up to one hour. For samples taken during low or intermittent flow events, the owner or operator must document and report the collection time and the reason for not obtaining a full one-hour sample with the NHV sampling results. We requested comment on the actual duration of flow that is achievable in practice for those cases where sampling for one-hour is technically infeasible on low pressure and intermittent gas streams, and why a one-hour sample would be technically infeasible for those cases.

Regarding the location for sampling, we noted that the March 2024 Final Rule required taking a sample of the inlet gas to the control device but did not require that the gas sample be taken directly at the inlet of the control device. We consider an "inlet gas sample" to be a sample taken within the control device header system in a location after all vent stream sources have been added to the control device header. While the EPA recognizes petitioners' concerns with installing sampling ports or "taps" on these source types, the March 2024 Final Rule does not specify a physical location where the sampling must occur. We therefore do not believe it is necessary to specify that sampling may occur at another "representative" location or specify such "representative" locations. The EPA also notes that the General Provisions in 40 CFR part 60 include procedures for alternatives to monitoring, including alternative locations for monitoring "when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements" – these provisions already address site-specific issues with conducting the alternative performance test (sampling demonstration) option.[135] Accordingly, we did not propose to change the current provisions in the March 2024 Final Rule regarding sampling location for the NHV grab sample option.

a. Sampling frequency

Comment: One commenter stated that while the EPA proposed revisions to the performance testing requirements, the EPA did not propose amendments to some of the most burdensome requirements (*e.g.*, the sampling frequency of two samples per day for 14 days with an ongoing demonstration of three samples every five years) for the sampling demonstration option for NSPS OOOOb or EG OOOOc, and the one-hour minimum sampling time for the twice daily samples, except in cases where low or intermittent flow makes one-hour sampling infeasible.[136]

Another commenter suggested that sampling using grab samples across multiple days adds useful flexibility and is a sound approach.[137] The commenter appreciated the additional flexibility that the EPA provided in the 14-day sampling process for control devices using grab samples for compliance purposes. The commenter stated that there would not be an expected change in control device vent gas compositions on days when

[135] See footnotes 48 and 49.
[136] Document ID No. EPA-HQ-OAR-2024-0358-0095.
[137] Document ID No. EPA-HQ-OAR-2024-0358-0094.

samples could not be taken. As such, they stated that allowing breaks in the 14-day periods for sites that do not use continuous sampling systems would provide representative results at a reduced cost and burden.

One commenter requested that the EPA require only one daily sample for manual grab sampling since two daily samples unnecessarily increases costs and emissions from travel.[138] This commenter asserted that two daily samples are unnecessary, and that the EPA should reduce the requirement to a single daily sample since the vent gas NHV is not expected to vary much between the two samples. The commenter asked the EPA to reduce this unnecessary sampling burden and revise the requirement to one daily sample for a total of 14 total samples.

One commenter stated that if the EPA retains continuous vent gas monitoring requirements for air- and steam-assisted control devices, the commenter supports the EPA's proposal to broaden the use of the 14-day alternative sampling methodology in 40 CFR 60.5417b(d)(8)(iii) to include steam-assisted and premix air-assisted flares and ECD.[139]

Response: The EPA is finalizing the rule to only require a 14-day NHV sampling demonstration for certain operating scenarios as summarized in section IV.B.2 of this preamble for all flare and ECDs. These exemptions will significantly reduce the sampling burden of acquiring two samples per day for 14 days. The EPA disagrees that the potential reduced vent gas NHV content for these operating scenarios will not vary much between the two daily samples and is maintaining the two samples per day requirement

[138] Document ID No. EPA-HQ-OAR-2024-0358-0083.
[139] Document ID No. EPA-HQ-OAR-2024-0358-0094.

over a period of 14 days, as currently prescribed by the NSPS OOOOb and EG OOOOc rules.

However, as previously explained in sections III.B and IV.B of this preamble, the EPA is allowing breaks for weekends and holidays which may occur during the 14-day sampling period, such that the 14 days do not have to be consecutive. Consecutive operating days are reasonable for continuous monitoring because these systems are present continuously. However, manual grab sample collection requires someone to be present at the site to collect samples each day, which, if required to be done on consecutive days, would require collection on weekends and potentially on holidays. The March 2024 Final Rule already allows for sampling beyond the 14 days if 28 samples cannot be collected during that timeframe. Allowing additional flexibility for non-consecutive operating day sampling can lengthen the time needed to collect samples and delay the conclusion of the NHV determination, but it does not reduce the number of samples required nor the representativeness of those samples. As such, we consider it reasonable to provide some flexibility in the grab sampling approach to allow twice daily sampling to determine the average NHV of the gas stream for 14 operating days, with no sampling day spaced more than 3 operating days apart from the previous sampling day.

b. Sampling location and duration

Comment: Several commenters expressed support for the EPA's proposed revision to allow NHV sampling at a representative location. Specifically, one of the commenters supported the proposed revisions to clarify that NHV sampling may be conducted "on the inlet gas which is routed to the enclosed combustion device or flare" to allow NHV sampling to occur at a representative location.[140]

Another commenter stated that the EPA's January 2025 Proposal would require that operators conduct the initial NHV demonstration sampling on ‘‘the inlet gas which is routed to the enclosed combustion device or flare."[141] The commenter noted that this may not address their concerns. Specifically, the commenter expressed concern that control devices receiving intermittent flow would require flaring solely for the purpose of collecting samples for NHV analysis. Instead, the commenter suggested the EPA should allow the option to collect samples from the process that can be diverted to a control device, in addition to collecting samples from the piping to the control device. For example, for associated gas control devices, the commenter stated that the operator could collect a sample from the on-pad sales gas system before entering the sales pipeline, rather than having to divert sales gas to a control device to collect a sample from the piping to the control device. In addition, the commenter urged the EPA to allow the collection of NHV samples from representative facilities, and they contended that operators should be allowed to collect representative samples if the sample originates from a representative well site or centralized production facility.

Several commenters stated that the NHV demonstration should allow for "representative" grab sampling and that the proposal may not go far enough in allowing this flexibility. One commenter explained that the proposed requirement to conduct sampling at "the inlet gas which is routed to enclosed combustor or flare" is unclear, given the EPA's statement that the change "will clarify that sampling upstream of the inlet

[140] Document ID No. EPA-HQ-OAR-2024-0358-0083.
[141] Document ID No. EPA-HQ-OAR-2024-0358-0092.

to the control device is allowed, provided that the sample is representative of the gas inlet to the control device."[142] The commenter stated their concern that "upstream of the inlet of the control device" is limiting and that the EPA should allow sampling from anywhere in the process that is representative of the gas that would be routed to the flare. As an example, the commenter described an associated gas process stream that can route to a sales line or a control device and stated that the rule should allow the operator to collect a sample from a location in the process going to the sales line, rather than along the piping or at the inlet to the control device. The commenter explained that, if required to collect the sample from the latter, the operator must divert gas to the flare that would otherwise go to sales, resulting in unnecessary emissions. Further, the commenter stated that if multiple streams route to the control device, it should be necessary only to sample the stream which the operator expects to have the lowest NHV. The commenter stated that the EPA proposed that "sampling may be conducted from a location on the control device piping header, provided the sampling location is downstream of all waste gas inlets into the header." The commenter stated their concern that this suggests that the operator must route all process streams to the control device to collect a sample, downstream of the comingling point; this could require diverting streams to the control device which normally routed to a non-emitting process and would result in additional emissions. The commenter provided as a solution that the EPA allow the operator to sample the process stream with the lowest expected NHV and if that stream is above the applicable NHV limit, it is unnecessary to sample the other, higher NHV streams. Finally, the commenter requested that the final rule allow operators to use samples from nearby, representative

[142] Document ID No. EPA-HQ-OAR-2024-0358-0088.

facilities that produce from the same reservoir/formation and have similar operating conditions and equipment. The commenter concluded that it is reasonable to expect these facilities to have very similar gas compositions and NHV.

Regarding the minimum one-hour sampling times for collecting NHV samples, several commenters contended that it is unnecessary to conduct one-hour sampling. One of the commenters[143] indicated that the EPA proposes that the collection time for an individual NHV sample may be less than one hour when it is not technically feasible (*e.g.*, low or intermittent), but the collection time must be as long as possible up to one hour. The commenter stated that while the proposed revision partially alleviates their concerns with sampling duration, it does not recognize that a one-hour sample collection time is unnecessary and should be removed. The commenter explained that typical sampling techniques require only a few minutes to collect a valid sample for NHV analysis, regardless of the flow conditions. According to the commenter, collecting or trying to collect a sample for an entire hour is unnecessary to demonstrate compliance with the minimum vent gas NHV requirement since the vent gas NHV of a stream is not expected to vary much within that hour.

Other commenters stated that one-hour sampling is contrary to the norms of sampling.[144] One commenter noted that while the proposal allows for reduced sampling where it is technically infeasible to conduct a one-hour sample due to LP or intermittent gas flow, which addresses technical infeasibility issues they raised in prior comments, it remains unnecessary to require the collection of a one-hour sample in any event.[145] The

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[143] Document ID No. EPA-HQ-OAR-2024-0358-0083.
[144] See SPL, Inc., SPL Letter to EPA, 1-2, EPA-HQ-OAR-2024-0358-0038-0032 (March 19, 2024) ("March SPL Letter").
[145] Document ID No. EPA-HQ-OAR-2024-0358-0088.

commenter requested that the EPA finalize the representative grab sampling revisions that they provided for NSPS OOOOb and include the same revisions in EG OOOOc.

Another commenter stated that for the NHV demonstration in 40 CFR 60.5417b(d)(8)(iii)(A) and (F), the EPA proposes to retain the one-hour minimum sampling time for twice-daily samples, except in cases where sampling for one hour is technically infeasible on LP or intermittent gas streams.[146] The commenter supported allowing an offramp for the one-hour minimum sampling time, and they suggested that the EPA go further and allow the use of representative grab samples for the initial compliance demonstrations requirements, rather than requiring a one-hour sample period.

Conversely, two commenters expressed that they do not support shorter sampling times. More specifically, a sample collected over a specified period of time (*e.g.,* one hour) is considered a composite sample because the sample collected is a "composite" of the gases which flowed through the source location over that specified time period, but a grab sample is considered a moment in time.[147] According to one commenter, there is a significant risk that the combination of the allowance for the use of Tedlar bags and the use of the term "grab sample" will replace the needed one-hour composite sample with a short duration sample. The commenter reported that over the past year, many samples collected to comply with NSPS OOOOb did not meet the minimum one-hour collection period. The commenter stated that early testing, which attempted to comply more with the one-hour collection periods, resulted in high test failure rates. The commenter asserted that in order to resolve these high test failure rates, without implementing the evacuated containers, heated lines, and other needed sampling system items, industry

[146] Document ID No. EPA-HQ-OAR-2024-0358-0092.
[147] Document ID No. EPA-HQ-OAR-2024-0358-0084, -0096.

simply shortened the duration of collection. The commenter stated that industry has shown the compositions and the associated calculated NHVs of the flare/ECD gas will highly vary over the one-hour collection period. Accordingly, the commenter stated, a short duration sample will not be representative of combustion gases. According to the commenter, this issue is further complicated by the EPA's proposal to allow for shorter duration testing as stated in the January 2025 Proposal.

According to the commenter, the industry collected one-hour samples at thousands of flares over the past year, in compliance with NSPS OOOOb and throughout the prior NSPS OOOOa testing. The commenter noted that tests show that the collection of gases has been technically feasible. In cases where the industry has struggled to produce compliant results as a result of collection practices, facility constraints, cost, and existing testing infrastructure the industry has claimed the testing itself is not feasible, cautioned the commenter.

Response: As noted in the January 2025 Proposal, the EPA does not believe it is necessary to specify that sampling may occur at another "representative" location or to specify such "representative" locations, and we assert that our clarification in the January 2025 Proposal that sampling may be conducted upstream of the inlet to the control device, provided that the sample is representative of the gas inlet to the control device, is sufficient. This is imperative considering that the finalized NHV sampling requirements will entail miscellaneous operating scenarios, where sampling further upstream of the control device (or at "representative facilities") would not provide a representative NHV sample. We recognize that some case-by-case determinations may be necessary due to the number of potentially affected sources, and potential operating design configurations.

As previously noted in section IV.B.3 of this preamble, the General Provisions in 40 CFR part 60 include procedures for alternatives to monitoring, including alternative locations for monitoring "when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements."[148]

Regarding the proposed provision to allow sampling times of less than one hour, the EPA notes that it will still require a minimum one-hour sample duration, except in cases where low or intermittent flow makes one-hour sampling infeasible for both NSPS OOOOb and EG OOOOc sources. The EPA recognizes that NHV content can vary over a given sampling period. However, the EPA also recognizes that industry has demonstrated that there can be some cases where sampling for a minimum period of one-hour may not be physically possible in certain situations. Accordingly, the EPA is allowing less than one-hour sampling times for cases where low or intermittent flow is present, provided that the sampling time used and the reason for the reduced sampling time is documented and reported and that the samples were taken during the period with the lowest expected NHV (*i.e.*, the period with the highest percentage of inerts). While sampling for a period of less than one hour is not considered ideal, the EPA believes that the NHV content during this shorter sampling period should be representative of the NHV content for that particular period of operation, which should also be indicative of the NHV content for that source had a one-hour sample been obtained. In turn, if there is any variance in the NHV content, it would then be reflected in the multiple samples taken over the course of the entire sampling program.

4. Methodologies for Compositional Analysis of the Gas Stream

[148] See footnotes 48 and 49.

The EPA reconsidered the requirements in the March 2024 Final Rule that limited the test method for determining the compositional analysis of the gas stream to American Society for Testing and Materials (ASTM) D1945-14 (R2019). The EPA recognizes that other rules in which vent gases are analyzed, such as 40 CFR part 63, NESHAP subpart CC (Refinery MACT)), allow the use of other test methods. In the January 2025 Proposal, the EPA solicited comment to expand the use of similar consensus-based standards (*e.g.*, GPA Midstream 2166 and GPA Midstream 2261) to consider if these additional available methods would alleviate petitioners' concerns that ASTM D1945-14 is not widely available and that testing laboratories do not have the capacity currently to enable its use.

In the January 2025 Proposal, the EPA also proposed to clarify that Tedlar bags may be used to satisfy the grab sampling requirements, provided that the Tedlar bag qualifies as an "evacuated container" as prescribed by section 8.2.1.1 of EPA Method 18. We requested comment on the need to clarify that Tedlar bags can be used and the limitation proposed on when Tedlar bags can be used.

Comment: Several commenters suggested that the EPA expand the use of consensus-based standards to those commonly and readily used by the oil and gas industry. These include, but are not limited to, the following:

- Combined Standards API MPMS 14.1 (8th ed.) / GPA 2166 (22) - Collecting and Handling of Natural Gas Samples for Analysis by Gas Chromatography
- GPA 2261 - Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography

One commenter stated that this will allow the operators to use the same service providers and laboratories retained for their other operations and ensure adequate capacity.[149] Additionally, these service providers and laboratories have typically been thoroughly vetted and audited by the operators and have been proven to provide accurate and defensible data.

Another commenter remarked that including these consensus-based standards will alleviate concerns that ASTM D1945-14 is not widely available and that testing laboratories do not currently have the capacity to support its use.[150] Furthermore, this commenter contended that ASTM D1945-14 is inappropriate for well sites, centralized production facilities, compressor stations, and gas plants since it evaluates components not typically found in vent gas from these operations (*e.g.*, helium). The commenter noted that concerns expressed about the availability of labs, analysis time, and cost with ASTM D1945-14 have not changed since the commenter submitted its previous reconsideration letter.

One commenter stated that GPA Midstream 2261 is equivalent to ASTM D1495-14D1945 in constituents, has a broader range of heavier hydrocarbons, elutes all gases sequentially without material peak overlap (including nitrogen and methane), meets the regulatory requirements of 40 CFR 60.54717b(d)(8), and employs thermal conductivity detectors.[151] The commenter provided a detailed analysis/rationale for each of these factors in its comment letter.

[149] Document ID No. EPA-HQ-OAR-2024-0358-0084.
[150] Document ID No. EPA-HQ-OAR-2024-0358-0083.
[151] Document ID No. EPA-HQ-OAR-2024-0358-0089.

Several commenters expressed that allowing more test methods would help lab capacity issues but may lead to inconsistent results. One commenter suggested that it is essential to ensure that all approved methods provide equally accurate and precise data.[152]

Regarding Tedlar bags, one commenter suggested that Tedlar bags be excluded from use for the collection of flare gas samples.[153] The commenter explained that Tedlar bags are not designed for the compositions and sampling handling requirements of typical flare gas. The commenter stated that the January 2025 Proposal cites section 8.2.1.1 of EPA Method 18. According to the commenter, EPA Method 18 is not a valid method for the collection and analysis of the gas typically found in flares. Section 1.2.1 of EPA Method 18 states, "[t]his method is designed to measure gaseous organics emitted from an industrial source. While designed for parts per million (ppm) level sources, some detectors are quite capable of detecting compounds at ambient levels, *e.g.*, ECD, ELCD, and helium ionization detectors." The commenter asserted that this method, and its allowed use of Tedlar bags, was designed for ppm level and ambient sources and that it was not designed and validated for percent level gaseous compounds, as found in typical flare gas. According to the commenter, the more appropriate EPA method for the sampling of the typical compositions and compound concentrations found in flare gas is EPA Method 0040, Sampling of Principal Organic Hazardous Constituents from Combustion Sources Using Tedlar Bags. However, the commenter stated that EPA Method 0040 clearly states that Tedlar bags are not applicable for the compounds typically found in flare gas. The commenter stated that hydrocarbon contamination contributed by the Tedlar bag has the potential of distorting the sample and biasing the

152 Document ID No. EPA-HQ-OAR-2024-0358-0078.
153 Document ID No. EPA-HQ-OAR-2024-0358-0084.

NHV high. Therefore, the commenter suggested that Tedlar bags be excluded from use for flare gas sampling.

Another commenter recommended that the final rule allow for the use of single cavity stainless steel constant volume cylinders as a vent gas collection method.[154] The commenter stated that the EPA proposed to allow Tedlar bags as an alternative sample collection method. The commenter agreed that alternative sample collection methods are necessary, as Summa canisters are not a good option for vent gas collection. The commenter strongly supported allowing Tedlar bags as an alternative sample collection method. In addition, the commenter requested that the EPA clarify that operators and laboratories may collect grab samples using single cavity stainless steel constant volume cylinders for sample collection, so long as they are maintained according to the requirements set forth in 43 CFR 3175 (Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Measurement of Gas).

Several commenters supported the use of Tedlar bags over air sampling canisters primarily due to cost, convenience, and ease of handling. One commenter explained that cleaning canisters is nearly impossible, particularly for rich gas streams (such as those from storage vessels), which leave residuals in canisters and further complicate cleaning and reuse.[155] The commenter explained that the conditioning of Tedlar bags is easier (as they fit easily into standard heating ovens), and Tedlar bags are available in larger quantities per shipment (which makes getting supplies easier).

Response: The EPA acknowledges that allowing additional test methods, especially GPA Midstream 2261 (which was the most cited addition to testing method

[154] Document ID No. EPA-HQ-OAR-2024-0358-0092.
[155] Document ID No. EPA-HQ-OAR-2024-0358-0089.

options), would provide additional flexibility to sources, as well as potential relief to analytical laboratories with substantial backlogs. Since GPA 2261 utilizes the same analytical equipment, including a similar procedure as the existing standard method, and generally provides equivalent results, we are allowing this method as an option (as GPA 2261-19) in the final rule for all sources. For those owners or operators with streams expecting a significant concentration of inert compounds, they should conduct the analysis according to ASTM D1945 or utilize the "single column method" in Section 2.1.4 of GPA 2261. Due to the concerns expressed by several commenters about potential issues that could arise from allowing the use of Tedlar bags to satisfy the grab sampling requirements specified by NSPS OOOOb and EG OOOOc, we will not be revising the sample media requirements for canisters currently specified by 40 CFR 60.5413b(d)(5), 60.5417b(d)(8), 60.5413c(d)(5), and 60.5417c(d)(8).

5. NHV_{cz} and NHV_{dil} for Air- and Steam-Assisted Flares and Enclosed Combustion Devices at Existing and New Sources

In the January 2025 Proposal, the EPA proposed to retain the NHV_{cz} and NHV_{dil} requirements for air- and steam-assisted flares for sources subject to NSPS OOOOb because, as noted in the November 2021 Action (86 FR 63246; November 15, 2021), we had received some data indicating that air- and steam-assisted flares have been found operating outside of the conditions necessary to achieve at least 98 percent control efficiency on a continuous basis. In the January 2025 Proposal, we disagreed with petitioners that these NHV-related parameters are not appropriate for assisted flares in the oil and gas industry, because we had evidence of poor-performing assisted flares in the oil and gas industry. We, therefore, proposed to conclude (as we had in the March 2024

Final Rule) that sufficient evidence exists demonstrating poor destruction efficiencies due to over-assisting a flare or ECD, and thus NHV compliance demonstrations are necessary to show that these particular control devices meet the requisite efficiency. The EPA requested comment on the proposed retention of the NHV_{cz} and NHV_{dil} provisions for new sources. We also requested comment on whether the NHV_{dil} parameter is appropriate for ECD with perimeter assist air and the appropriate effective diameter to use in the calculation of NHV_{dil}, if it is retained, particularly for devices with multiple burner tips within the ECD.

Regarding statements that 40 CFR 60.5417b(d)(8)(iii)(H) appears to not allow alternative test methods to continuously monitor NHV_{cz} and NHV_{dil}, we noted that the provisions at 40 CFR 60.5417b(d)(8)(iii) are specific to the 14-day alternative performance test (sampling demonstration) option and do not apply to continuous monitoring. We did not include provisions for a 14-day demonstration using continuous monitoring of NHV_{cz} and NHV_{dil} because assist rates could be changed and alter the control device's performance. Continuous monitoring using alternative test methods is expressly provided for in 40 CFR 60.5412b(d) and 60.5415b(f)(1)(xi). Additionally, we proposed to clarify in 40 CFR 60.5417b(d)(8)(vi) that continuous monitoring of NHV_{cz} and, if applicable, NHV_{dil} using an approved alternative method as provided under 40 CFR 60.5412b(d)(1)(i) and (ii) is allowed and that, when using this alternative test method, owners and operators are not required to monitor NHV of the vent gas as specified in 40 CFR 60.5412b(d)(8)(ii) or monitor flow rates as specified in 40 CFR 60.5412b(d)(8)(vi) provided they can demonstrate that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed 18.3 meter/second (60 feet/second). The

EPA requested comment on the proposed clarifications when using the alternative test method to demonstrate continuous compliance and requested comment on whether and how to use such monitoring as part of the 14-day sampling demonstration.

With respect to the monitoring requirements for NHV_{cz} and NHV_{dil} for air- and steam-assisted flares at new sources, the EPA acknowledged the petitioners' concerns but did not propose significant changes to this requirement for new sources subject to NSPS OOOOb. However, in reviewing these requirements, we noted that the requirements in 40 CFR 60.5417b(d)(8)(vi) reference NHV determinations using the lowest NHV result of the sampling demonstration in 40 CFR 60.5417b(d)(8)(iii), but 40 CFR 60.5417b(d)(8)(iii) does not have provisions for steam-assisted nor for certain air-assisted flares or ECD. Therefore, we proposed to clarify that 40 CFR 60.5417b(d)(8)(iii) can be used for any steam- or air-assisted flare (including perimeter assist air) or ECD, and that the effective vent gas NHV to allow the use of the demonstration is 300 Btu/scf when using continuous 14-day sampling or 360 Btu/scf when using the 14-day grab sampling approach. This revision in 40 CFR 60.5417b(d)(8)(iii) is necessary considering the calculation provision in 40 CFR 60.5417b(d)(8)(vi) and corrects an unintended error in the March 2024 Final Rule. The EPA also requested comment on the use of the proposed use of the 14-day sampling demonstration in 40 CFR 60.5417b(d)(8)(iii) for air- and steam-assisted flares, particularly those at new sources subject to the NHV_{cz} and NHV_{dil} requirements.

With the alternative sampling provisions being proposed in 40 CFR 60.5417b(d)(8)(iii) and the assessments outlined in 40 CFR 60.5417b(d)(8)(iv), we expect that few facilities will need to install continuous monitoring systems. With the monitoring options provided, we considered the costs of the monitoring provisions to be reasonable and necessary to ensure proper operation of these flares at new sources and therefore retain the NHV_{cz} and NHV_{dil} requirements in NSPS OOOOb.

Conversely, the requirement to conduct monitoring for NHV_{cz} and NHV_{dil} at existing sources was included in EG OOOOc in error. The EPA did not conduct Refinery MACT cost level monitoring for existing sources and stated in the preamble to the March 2024 Final Rule that monitoring of NHV_{cz} and NHV_{dil} was not required for existing sources due to concerns about retrofitting existing flares to meet the requirements.[156] The EPA proposed to correct this inadvertent error by removing the requirements to conduct monitoring of NHV_{cz} and NHV_{dil} at existing sources and specifying the requirements for these control systems is an NHV of 300 Btu/scf in the vent gas. The EPA requested comment on the appropriateness of using an NHV of 300 Btu/scf in the vent gas for air- and steam-assisted flares or ECD at existing sources for demonstrating compliance with the combustion efficiency requirements for these control devices.

Comment: The EPA received numerous comments regarding the NHV_{cz} and NHV_{dil} provisions discussed in the January 2025 Proposal, many of which were out-of-scope from the proposal. Regarding the issues for which the EPA specifically requested comment, one commenter[157] noted that for new NSPS OOOOb sources, the EPA proposed to retain the NHV_{cz} and NHV_{dil} requirements, which is already a Refinery MACT requirement. The commenter reminded the EPA that petitioners provided data, experience, and knowledge on why these testing requirements are inappropriate (*e.g.*,

[156] 89 FR 16895, 16967 (March 8, 2024).
[157] Document ID No. EPA-HQ-OAR-2024-0358-0095.

non-steady state flow) and are excessively costly ($1 million or more). The commenter requested that the EPA remove this requirement from the proposed rule.

Conversely, one commenter[158] believed the Agency should retain the requirement to monitor NHV_{cz} and NHV_{dil} for air- and steam-assisted flares and ECD at new NSPS OOOOb sources. The commenter agreed with the EPA's statement in the proposed rule that there is sufficient evidence to demonstrate that over-assisting a flare or ECD leads to poor destruction efficiencies, necessitating NHV compliance demonstrations. The commenter also agreed that the NHV_{cz} and NHV_{dil} parameter terms account for the reduction in heating value caused by the introduction of air or steam and that requiring compliance with the NHV_{cz} and NHV_{dil} limits for air- and steam-assisted flares and ECD constitutes BSER under CAA section 111(a)(1).

Regarding the alternative test method option to demonstrate continuous compliance and whether and how to use such monitoring as part of the 14-day sampling demonstration for air- and steam-assisted flares, particularly those at new sources subject to NHV_{cz} and NHV_{dil} requirements, one commenter[159] stated that although NSPS OOOOb includes provisions for alternate test methods and alternate NHV_{cz} and NHV_{dil} demonstrations in lieu of monitoring, those alternatives may not be feasible for every control device. For example, the commenter stated that OTM-56 can only be used for flares since the Video Imaging Spectral Radiometer (VISR) camera needs a clear view of the flame. The commenter explained that alternate test methods are costly to implement and take time for Agency approval, so they are not an option for immediate compliance and unlikely to be used by small operators. Moreover, the alternate NHV_{cz} and NHV_{dil}

[158] Document ID No. EPA-HQ-OAR-2024-0358-0086.
[159] Document ID No. EPA-HQ-OAR-2024-0358-0083.

demonstrations are problematic given the intermittent operation of control devices at production sites, explained the commenter.

Another commenter[160] urged the EPA to remove the NHV_{cz} and NHV_{dil} requirements for all control devices subject to NSPS OOOOb. The commenter explained that oil and natural gas facilities are fundamentally different than petroleum refineries in that they do not operate at steady state conditions. The commenter explained that this highly variable, non-steady state flow mandates that equipment be sized much larger than ideal steady state conditions and makes flow measurement infeasible. The commenter explained that costs are also an issue, in that upstream facilities do not have the necessary utilities and instrumentation resources that a refinery has, nor do they have instruments that can operate reliably under the varying operating conditions found at oil and natural gas facilities. The commenter added that the alternative NHV_{cz} and NHV_{dil} demonstrations also are problematic, given that the production site does not operate under steady state conditions.

Regarding the appropriateness of using an NHV of 300 Btu/scf in the vent gas for air- and steam-assisted flares or ECD at existing sources for demonstrating compliance with the combustion efficiency requirements for these control devices, one commenter[161] stated that EG OOOOc air- and steam-assist flare vent gas limit of 300 Btu/scf is a reasonable alternative to the NHV_{cz} and NHV_{dil} limits. The commenter supported the flare vent gas limit of 300 Btu/scf as a reasonable alternative to the NHV_{cz} and NHV_{dil} limits in EG OOOOc. The commenter noted that the EPA did not conduct Refinery MACT cost level monitoring for existing sources and stated in the preamble to the March

[160] Document ID No. EPA-HQ-OAR-2024-0358-0088.
[161] Document ID No. EPA-HQ-OAR-2024-0358-0094.

2024 Final Rule that monitoring of NHV_{cz} and NHV_{dil} was not recommended as part of the EGG for existing sources due to concerns about retrofitting existing flares to meet the requirements.

Response: While some commenters have requested that the removal of NHV_{cz} and NHV_{dil} requirements from NSPS OOOOb, the EPA has made it clear that these monitoring requirements are appropriate and necessary for these types of devices, as there is sufficient evidence to demonstrate that over-assisting a flare or ECD leads to poor destruction efficiencies, necessitating NHV compliance demonstrations (*i.e.*, it is understood that inert gases can be introduced to steam-assisted, air-assisted, and perimeter assist air flares). However, the EPA recognizes that the operation of control devices at oil and natural gas facilities can be fundamentally different than petroleum refineries, which also have NHV_{cz} and NHV_{dil} requirements prescribed under the Refinery MACT. The EPA believes that this final rule, which will impose NHV sampling requirements for only those sources and situations where inert gases are present or under miscellaneous operating scenarios that may lower the NHV of the inlet gas stream, will result in a more manageable monitoring and testing situation industry-wide, and allow the evaluation of certain situations on a case-by-case basis. As previously noted in section IV.B.3 of this preamble, the General Provisions in 40 CFR part 60 include procedures for alternatives to monitoring, including alternative locations for monitoring "when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements".[162]

[162] See footnotes 48 and 49.

Based on our analysis of the data submitted by industry, we find that gas streams expected to be routed to a flare or ECD at sites that do not have sources with inerts will have a NHV of well over 800 Btu/scf. At these high NHVs, we expect that facilities will always be compliant with the NHV_{cz} or NHV_{dil} operating limits, even at low flare gas flow rates. Because of the high assurance that these flares or ECD will operate at a high efficiency at all times that vent gas is directed to the devices, we find it reasonable to exempt these flares and ECD from the monitoring and compliance requirements, provided that these devices do not receive streams with inerts that can lower the NHV inlet to the flare or ECD. When inerts are included in the inlet gas stream, it is much more likely that the NHV of the vent gas would fall below 800 Btu/scf and that the NHV_{cz} or NHV_{dil} will fall below the Btu content thresholds. Therefore, we are finalizing the requirement to conduct assessments or monitor NHV and flows to determine continuous compliance with the NHV_{cz} or NHV_{dil} operating limits in cases where inert gases are added or for other miscellaneous scenarios which decrease the NHV_{cz} or NHV_{dil} content of the inlet stream gas to all flare and ECDs for new sources.

The EPA did not receive adverse comments on the proposal to increase the minimum NHV content threshold from 270 to 300 Btu/scf for air- or steam-assisted flares or ECD for existing EG OOOOc sources. Hence, the EPA is finalizing this aspect of the rule as proposed.

The EPA did not receive specific comments on whether the NHV_{dil} parameter is appropriate for ECD with perimeter assist air and the appropriate effective diameter to use in the calculation of NHV_{dil}, particularly for devices with multiple burner tips within the ECD. Hence, the EPA is finalizing these aspects of the rule as proposed.

No additional changes are being made to the NHV_{dil} and NHV_{cz} requirements at this time based upon other comments and suggestions received, which are considered out-of-scope for this rulemaking.

6. Other Miscellaneous Comments on the NHV Provisions

The following subsections describe other miscellaneous provisions of the NSPS OOOOb and EG OOOOc rules that pertain to NHV sampling that the EPA either wishes to address or clarify based upon comments received regarding the January 2025 Proposal.

a. NHV temperature basis

In the January 2025 Proposal, the EPA proposed to clarify that the NHV of the vent gas stream must be determined in Btu/scf and not Btu/lb, where the standard condition temperature is 20°C. More specifically, regarding the units in which the NHV is determined as prescribed in the March 2024 Final Rule, we do not disallow the use of measurement methods that determine concentrations in terms of weight fractions, but the weight fractions must be converted to volume fractions because the calculations referenced therein from 40 CFR part 63 use Btu/scf, not Btu/lb. Therefore, we did not propose to change the units in the March 2024 Final Rule but rather proposed to clarify that NHV for individual components must be determined in units of Btu/scf consistent with the existing specification using published values of the component NHV per mole at 25°C and one atmosphere and using 20°C as the standard temperature for determining the volume corresponding to one mole of vent gas. We proposed to clarify that since the standard temperature at 40 CFR 60.18(f)(3) is 20°C, the NHV under NSPS OOOOb and EG OOOOc must be determined at this standard temperature. The Agency proposed these clarifications to ensure the NHV determinations are conducted consistently and accurately.

The EPA received only supporting comments on this issue and is finalizing this clarification as proposed.

b. Averaging periods

In the January 2025 Proposal, the EPA also proposed to clarify that for the purpose of determining the hourly average of the NHV for continuously sampled (*i.e.*, sampled continuously for 14 consecutive days) inlet streams, the hourly average shall be determined on a block (and not a rolling) average. The EPA proposed this clarifying edit to ensure that all owners and operators are using the same averaging timeframe and that it is not left to individual interpretation whether the average should be a block average or a rolling average. Block averages are required for other averaging time periods in the March 2024 Final Rule, and we consider this change to be warranted for consistency and clarity.

The EPA received no comments on this issue and is finalizing this clarification as proposed.

c. Compliance timing and deadlines

The EPA also proposed a change to address compliance timing pending the re-evaluation that must occur after a process change that potentially reduces the NHV of the gas sent to an flare or ECD. More specifically for continuous monitoring, which must occur after the results of periodic monitoring indicate the vent stream is not sufficiently above the required NHV, we proposed that continuous monitoring should commence within 60 days after the re-evaluation indicates that the inlet gas stream does not meet the limits. The EPA also proposed to clarify, for both periodic testing and re-evaluations which occur after a process change, that if the results of the grab sampling indicate that the vent stream is not sufficiently above the required NHV, continuous monitoring using a calorimeter, GC, MS, or continuous grab sampling (*i.e.*, once every eight hours) must commence within the specified timeframe.

The EPA received no comments on this issue and is finalizing this clarification as proposed.

V. How do these final amendments impact the implementation of EG OOOOc?

The EPA's final amendments discussed in section III of this preamble will not significantly impact the implementation of EG OOOOc or the State planning process. Based on the EPA's reconsideration, we are finalizing amendments that revise two narrow aspects of the EG: the associated gas temporary flaring provisions for certain situations, and the NHV continuous monitoring and alternative performance test (sampling demonstration) provisions for certain combustion control devices. These final amendments do not alter in any way the EPA's identified BSER in the EG, or the EPA's identified degree of emissions limitation achievable via application of that BSER. Any changes that a State or Tribe may make to their developing plan as a result of this final action will be minor, and the State or Tribe should be able to make such changes before their plans are required to be submitted for approval. The EPA does not anticipate that States will require additional time for State plan submittal solely because of the changes finalized in this rulemaking.

However, after the January 2025 Proposal was published, the EPA published an IFR to extend certain deadlines pertaining to the March 2024 Final Rule in July 2025 and later issued a final rule in December 2025 confirming those amendments and making further changes to the compliance deadlines in the IFR related to NHV monitoring and the initial reporting deadline.[163] Relevant to this discussion, in the IFR, the EPA extended the State plan submittal deadline in EG OOOOc from March 9, 2026, to January 22, 2027.

As indicated in section I.B of this preamble, the issuance of the CAA section 111(d) final EG does not impose binding requirements directly on existing sources. 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 (those that were existing sources on or before December 6, 2022). Further, under the TAR, eligible Tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a State, and Tribes are authorized under the TAR to develop and implement their own air quality programs, or portions thereof, under the CAA. The response to comments on the January 2025 Proposal on this section of this preamble is in the EPA's RTC document for the final rule.[164]

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders (EO) is available at *https://www.epa.gov/laws-regulations/laws-and-executive-orders*.

[163] 90 FR 35966 (July 31, 2025) and 90 FR 55671 (December 3, 2025).
[164] Reconsideration of 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 January 2025, Proposed Rule (90 FR 3734; January 15, 2025).

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant action under EO 12866 that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Economic Impact Analysis for 2025 Oil and Natural gas NSPS & EG Reconsideration*, is available in the docket.

We present the estimated PV and EAV of the estimated cost savings of this final reconsideration in 2024 dollars over the 2024 to 2038 period. The cost savings are represented in this analysis as the reduction in the number of affected sources and a reduction in the number of tests required for each affected source for the changes finalized in this reconsideration. In simple terms, these cost savings are an estimate of the decreased industry expenditures resulting from the final changes to the March 2024 Final Rule requirements. Under this final action, emissions changes and benefits from emission changes were not quantified, nor were cost changes from the temporary flaring provisions. Qualitatively, the changes to the temporary flaring limitation could result in cost savings and increases to emissions, while we do not expect any emissions changes to result from the changes to the NHV testing compliance demonstration.

Table 3 presents the estimated cost savings 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 EIA).

(*i.e.*, the primary baseline analyzed in the EIA). This table presents the PV and EAV of these estimates discounted at three percent and seven percent.

Table 3–Present Value and Equivalent Annualized Value of Compliance Cost Savings Estimates of the Final Action from 2024-2038 (Millions of 2024$)

	3 Percent Discount Rate	7 Percent Discount Rate
Present Value	2,480	1,900
Equivalent Annualized Value	208	209

The analysis, which is contained in the Economic Impact Analysis for this rulemaking, is consistent with EO 12866 and is available in the docket for this action.

B. Executive Order 14192: Unleashing Prosperity Through Deregulation

This action is considered an Executive Order 14192 deregulatory action. Details on the estimated cost savings of this final rule can be found in the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

OMB has approved the information collection activities contained in this rule under the PRA and has assigned OMB control number 2060-0721 to NSPS OOOOb and EG OOOOc. You can find a copy of the information collection request (ICR) in the docket for this rule, and it is briefly summarized here. The EPA has revised the approved ICR to include small changes to incorporate the EPA's final recordkeeping and reporting to indicate whether the flare or ECD receives inert gases or other streams which may lower the NHV of the combined stream as discussed in section III.B of this preamble. The EPA estimates an average of 48 respondents will be affected by this requirement over the three-year period (2024–2026). The average annual burden for the recordkeeping and reporting requirements for these owners and operators is estimated at 83 person-hours, with an average annual cost of $6,393 (2024$) over the three-year period.

The EPA has also revised the approved ICR to include burden estimates for the maintenance of records associated with the final requirements. Specifically, the EPA includes burden estimates in the revised ICR for the records and annual reporting included in the final rule related to the use of the associated gas extended flaring allowance under “exigent circumstances” as specified in section III.A of this preamble. The incremental increase in burden that would be associated with these recordkeeping and reporting requirements relative to the baseline is estimated at two hours per event annually over the three-year period (2024–2026) at an average annual cost of $176 per flaring event over the three-year period. The occurrence of flaring that could potentially be claimed due to “exigent circumstances” is unknown. However, we expect that a maximum of 16 percent of flaring events could potentially require an owner or operator to need to extend flaring beyond 72 hours due to “exigent circumstances.”

The burden associated with the two aforementioned requirements under this final action minimally affects the ICR burden estimated for compliance with EG OOOOc with an estimated annual cost increase of less than one percent for the States. Provided below is a summary of the ICR burden associated with the final notification, recordkeeping and reporting requirements.

Respondents/affected entities: Oil and natural gas owners and operators.

Respondent’s obligation to respond: Mandatory.

Estimated number of respondents: 48

Frequency of response: Annually.

Total estimated burden: 86 hours per year. Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $6,570 per year (2024$). There are no capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, an ICR 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.

The approved ICR document that the EPA prepared was assigned OMB Control No. 2060–0721 and EPA ICR number 2523.07. You can find a copy of the previously submitted ICR in Docket EPA-HQ-OAR-2021-0317. The revised ICR document that the EPA prepared for this reconsideration final rule has been assigned OMB Control No. 2060–0721 and EPA ICR number 2523.08. You can find a copy of the revised ICR in Docket EPA-HQ-OAR-2024-0358.

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. In making this determination, the EPA concludes that the impact of concern for this rule is any significant adverse economic impact on small entities and that the Agency is certifying that this rule will not have a significant economic impact on a substantial number of small entities because the rule has reduced net regulatory burden on the small entities subject to the rule. This action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements,[165] providing additional flexibilities to entities

[165] The EPA convened a Small Business Advocacy Review (SBAR) Panel prior to the November 2021 Action that was ultimately finalized in the March 2024 Final Rule.

subject to the NSPS requirements and to the model rules within EG OOOOc. Specifically, those flexibilities include extending the limitation on temporary flaring from 24 to 72 hours, granting exemptions from monitoring for an expanded number of gas streams due to high NHV content, allowing sampling to be conducted upstream of the control device inlet for operators meeting the NHV compliance demonstration via the alternative performance test, and allowing breaks in performance testing over weekends and holidays during the 14-day period for the performance test option. We have therefore concluded that this action will have reduced net regulatory burden for all directly regulated small entities. For instance, on average, we estimate cost savings of roughly $19,000 per well site due to the changes to the NHV testing provisions across all business size classifications. For further details, see the document, *Economic Impact Analysis for 2025 Oil and Natural Gas NSPS & EG Reconsideration*, in the docket.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million 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 addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements.

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 addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements.

G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action does not have Tribal implications as specified in EO 13175. This action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements. Thus, EO 13175 does not apply to this action. However, consistent with the EPA Policy on Consultation with Indian Tribes, the EPA offered consultation to all Federally Recognized Tribes during the development of this action on December 23, 2024. No Tribes requested consultation.

H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety

Risks

The EPA interprets EO 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2-202 of the EO. The EPA believes that it is not practicable to assess whether an environmental health risk or safety risk affecting children may exist prior to this action. This action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements and does not result in any changes to the BSER of NSPS OOOOb or EG OOOOc. The EPA believes that the EPA's Policy on Children's Health also does not apply.

Therefore, 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, EPA's Policy on Children's Health also 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, we have concluded that this action is not likely to have any adverse energy effects because this action addresses two discrete compliance requirement aspects of NSPS OOOOb and the model rules within EG OOOOc based on petitions for reconsideration received on the March 2024 Final Rule requirements and does not result in any changes to the BSER of NSPS OOOOb or EG OOOOc.

J. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR part 51

This action does not involve any new technical standards. Therefore, the NTTAA does not apply. In this rule, the EPA is including regulatory text for 40 CFR part 60, subparts OOOOb and OOOOc that includes incorporation by reference. In accordance with requirements of 40 CFR 60.17, the EPA is incorporating the following two standards by reference.

- GPA Standard 2261-19 (GPA 2261-19), Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, (Revised 2019), IBR approval requested for NSPS subpart OOOOb §60.5417b(d)(8)(ii)(D) and NSPS subpart OOOOc §60.5417c(d)(8)(ii)(D). This is a method for determining the chemical composition of natural gas and similar gaseous mixtures using a Gas Chromatograph. This method uses a gas chromatograph to separate and quantify hydrocarbons and non-hydrocarbons. This information can be used to calculate the Btu content of the natural gas sample.

- ASTM D1945-14 (Reapproved 2019), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved December 1, 2019; IBR approval requested for §§ 60.5417b(d)(8)(ii)(D); 60.5417c(d)(8)(ii)(D). This method covers the determination of the chemical composition of natural gases and similar gaseous mixtures within the range of composition. The method uses gas chromatography to physically separate the component in the sample and compares them against calibration data from a reference standard. This method is used to determine gas properties such as heating value.

The GPA 2261-19 standard is available at the GPA Midstream website at the following location: GPA Midstream Association, 6060 American Plaza, Suite 700, Tulsa, OK 74135; phone: (918) 493-3872; website: *www.gpamidstream.org*. GPA offers memberships or subscriptions that allows access to their methods.

ASTM D1945-14 is available at ASTM International, 1850 M Street NW, Suite 1030, Washington, DC 20036. See *https://www.astm.org/*. This standard is available to everyone at a cost determined by the ASTM ($96). The ASTM also offers memberships or subscriptions that allow unlimited access to their methods. The cost of obtaining these methods is not a significant financial burden, making the methods reasonably available to stakeholders.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit the rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

Lee Zeldin,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency amends part 60 of title 40, chapter I, of the Code of Federal Regulations as follows:

PART 60 – STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq*.

Subpart A – General Provisions

2. Amend § 60.17 by revising paragraphs (h)(78) and (m)(5) to read as follows:

* * * * *

(h) * * *

(78) ASTM D1945-14 (Reapproved 2019), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved December 1, 2019; IBR approved for §§ 60.485b(g); 60.5417b(d); 60.5417c(d).

* * * * *

(m) * * *

(5) GPA Standard 2261-19 (GPA 2261-19), Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, (Revised 2019), IBR approved for §§ 60.4415(a); 60.5417b(d); 60.5417c(d).

* * * * *

Subpart OOOOb – Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022

3. Amend § 60.5377b by revising paragraphs (b) through (g) to read as follows:

§ 60.5377b What GHG and VOC standards apply to associated gas wells at well affected facilities?

* * * * *

(b) For associated gas wells that commenced construction between May 7, 2024 and May 7, 2026, you can comply with the requirements in paragraph (f) of this section continually upon startup instead of paragraph (a) of this section until May 7, 2026 if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons in accordance with paragraph (g) of this section. After May 7, 2026, you must continually comply with paragraph (a) of this section at all times.

(c) For associated gas wells that commenced construction between December 6, 2022, and May 7, 2024, and for associated gas wells that undergo reconstruction or modification after December 6, 2022, you can comply with the requirements in paragraph (f) of this section instead of paragraph (a) of this section if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons in accordance with paragraph (g) of this section. Associated gas wells that are modified or reconstructed must comply with paragraph (a) or (f) of this section upon startup and at all times thereafter.

(d) If you are complying with paragraph (a) of this section, you may temporarily route the associated gas to a flare or control device that achieves a 95.0 percent reduction in VOC and methane emissions in the situations and for the durations identified in paragraph (d)(1), (2), (3), or (4) of this section. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the control device must meet the conditions specified in § 60.5412b during the period when the associated gas is routed to the flare. Records must be kept of all instances in which associated gas is temporarily routed to a flare or to a control device in accordance with § 60.5420b(c)(3)(i)(B) and reported in the annual report in accordance with § 60.5420b(b)(4)(i)(B).

(1) During a malfunction or incident that endangers the safety of operator personnel or the public you are allowed to route associated gas to a flare or control device until the malfunction or incident is resolved, but not longer than 72 hours per incident.

Temporarily routing associated gas to a flare or control device is allowed only until the malfunction or incident is resolved. Notwithstanding the previous sentences, if there are exigent circumstances that reasonably require routing to a flare or control device for more than 72 hours, paragraphs (d)(1)(i) through (iii) of this section apply.

(i) An "exigent circumstance" for purposes of paragraph (d)(1) of this section is a situation that results in the inability to reasonably access a site with the necessary equipment and personnel to address and resolve incidents that cause the need to temporarily flare associated gas for more than 72 hours. This includes circumstances where there is a need to flare beyond 72 hours due to an unexpected malfunction event and equipment needed to resolve an incident are not readily available due to an owner's or operator's inability to secure the required equipment for reasons beyond an owner's or operator's control (*i.e.*, supply chain issues); or there is a temporary shortage of personnel needed to resolve an incident due to a circumstance such as a declared national pandemic that is beyond the owner's or operator's control.

(ii) Temporarily routing associated gas to a flare or control device is allowed until the malfunction or incident is resolved, but shall not be longer than 72 hours after the site can be accessed following the passing of the exigent circumstance.

(iii) For instances where you route associated gas to a flare or control device for more than 72 hours, you must meet the reporting requirements specified in § 60.5420b(b)(4)(i)(B)(*4*) and must maintain the records specified in § 60.5420b(c)(3)(v).

(2) During repair and maintenance, including blow downs, a production test, or commissioning, you are allowed to route associated gas to a flare or control device until the incident is resolved, but no longer than 72 hours per incident. Temporarily routing

associated gas to a flare or control device is allowed only until the incident is resolved. Notwithstanding the previous sentences, if there are exigent circumstances that reasonably require routing to a flare or control device for more than 72 hours, paragraphs (d)(1)(i) through (iii) apply.

(3) For wells complying with paragraph (a)(1) of this section, during a temporary interruption in service from the gathering or pipeline system you are allowed to route to a flare or route to a control device for the duration of the temporary interruption not to exceed 30 days per incident.

(4) During periods when the composition of the associated gas does not meet pipeline specifications for sources complying with paragraph (a)(1) of this section, or when the composition of the associated gas does not meet the quality requirements for use as a fuel for sources complying with paragraph (a)(2) of this section, or when the composition of the associated gas does not meet the quality requirements for another useful purpose for sources complying with paragraph (a)(3) of this section, you are allowed to route to a flare or control device until the associated gas meets the required specifications or for 72 hours per incident, whichever is less.

(e) If you are complying with paragraph (a), (d), or (f) of this section, you may vent the associated gas in the situations and for the durations identified in paragraph (e)(1), (2), or (3) of this section per incident. The cumulative period of venting must not exceed 24 hours for any calendar year. Records must be kept of all venting instances in accordance with § 60.5420b(c)(3)(ii) and reported in the annual report in accordance with § 60.5420b(b)(4)(ii).

(1) For up to 12 hours per incident to protect the safety of personnel.

(2) For up to 30 minutes per incident during bradenhead monitoring.

(3) For up to 30 minutes per incident during a packer leakage test.

(f) You must route the associated gas to a control device that reduces methane and VOC emissions by at least 95.0 percent. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411b(a) and (c) and the control device must meet the conditions specified in § 60.5412b.

(1) For associated gas wells identified in paragraph (b) of this section, you can comply with the requirements in paragraph (f) of this section for up to a one year period if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons in accordance with paragraph (g) of this section. This allowance is renewable each year with an updated technical infeasibility demonstration and certification in accordance with paragraph (g) of this section. Associated gas wells identified in paragraph (b) of this section are not allowed to comply with the requirements in paragraph (f) of this section after May 7, 2026.

(2) For associated gas wells identified in paragraph (c) of this section, you can comply with the requirements in paragraph (f) of this section for up to a one year period if you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons in accordance with paragraph (g) of this section. This allowance is renewable each year with an updated technical infeasibility demonstration and certification in accordance with paragraph (g) of this section.

(g) For affected sources identified in paragraphs (b) and (c) of this section that are complying with the requirements in paragraph (f) of this section, you must demonstrate that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons by providing a detailed analysis documenting and certifying the technical reasons for this infeasibility.

(1) The demonstration must address the technical infeasibility for all options identified in paragraphs (a) through (4) of this section.

(2) This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer or other qualified individual shall state: “I certify that the assessment of technical and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of § 60.5377b(b). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.”

(3) This demonstration and certification are valid for no more than 12 months. You must re-analyze the feasibility of complying with paragraphs (a)(1) through (4) of this section and finalize a new demonstration and certification each year.

(4) Documentation of these demonstrations, along with the certifications, must be maintained in accordance with § 60.5420b(c)(3)(iii) and submitted in annual reports in accordance with § 60.5420b(b)(4)(iii)(C) and (D).

*   *   *   *   *

4. Amend § 60.5417b by revising paragraph (c)(1) introductory text, paragraphs (d)(7) and (8), (g)(1), and (i)(6)(v) to read as follows:

§ 60.5417b   What are the continuous monitoring requirements for my control devices?

* * * * *

(c) * * *

(1) Except for continuous parameter monitoring systems used to detect the presence of a pilot or combustion flame, each continuous parameter monitoring system must measure data values at least once every hour and record the values for each parameter as required in paragraph (c)(1)(i) or (ii) of this section. Continuous parameter monitoring systems used to detect the presence of a pilot or combustion flame must record a reading at least once every 5 minutes.

* * * * *

(d) * * *

(7) For a combustion control device whose model is tested under § 60.5413b(d), continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) and (vi) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section.

(8) For an enclosed combustion device, other than those listed in paragraphs (d)(1) through (3) and (7) of this section, or for a flare, continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section. Additionally, for enclosed combustion devices or flares that are air-assisted or steam-assisted, the continuous monitoring systems specified in paragraph (d)(8)(vi) of this section.

(i) After January 22, 2027, continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

(ii) Except as provided in this paragraph (d)(8)(ii) and paragraphs (d)(8)(iii) and (vi) of this section, use one of the following methods to continuously determine the NHV of the inlet gas to the enclosed combustion device or flare at standard conditions. If the inlet gas stream to the flare or enclosed combustion device does not include streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.*, vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), the NHV of the inlet stream is considered to be sufficiently above the minimum required NHV for the inlet gas, and you are not required to conduct the continuous monitoring in this paragraph (d)(8)(ii) of this section or the demonstration in paragraph (d)(8)(iii) of this section, but you must submit the report in § 60.5420b(b)(11)(v)(I) and maintain the record in §

60.5420b(c)(11)(vi) indicating that the flare or enclosed combustion device does not receive inert gases or other vent gas streams which may lower the NHV of the combined stream.

(A) A calorimeter with a minimum accuracy of ±2 percent of span.

(B) A gas chromatograph that meets the requirements in paragraphs (d)(8)(ii)(B)(*1*) through (*5*) of this section.

(*1*) You must follow the procedure in Performance Specification 9 of appendix B of this part, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(*2*) You must meet the accuracy requirements in Performance Specification 9 of appendix B of this part.

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the gas chromatograph in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(B)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. Use the response factor for the nearest normal hydrocarbon (i.e., n-alkane) in the calibration mixture to quantify unknown components detected in the analysis. Use the response factor for n-pentane to quantify unknown components detected in the analysis that elute after n-pentane.

(*5*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published values for the net heating value per mole at 25 °C and 1 atmosphere and use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(C) A mass spectrometer that meets the requirements in paragraphs (d)(8)(ii)(C)(*1*) through (*6*) of this section.

(*1*) You must meet applicable requirements in Performance Specification 9 of appendix B of this part for continuous monitoring system acceptance including, but not limited to, performing an initial multi-point calibration check at three concentrations following the procedure in Section 10.1. A single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to NIST standards.

(*2*) The average instrument calibration error (CE) for each calibration compound at any calibration concentration must not differ by more than 10 percent from the certified cylinder gas value. The CE for each component in the calibration blend must be calculated using the following equation:

Equation 1 to paragraph (d)(8)(ii)(C)(*2*)

$$CE = \frac{C_m - C_a}{C_a} \times 100$$

Where:
C_m = Average instrument response (ppm).
C_a = Certified cylinder gas value (ppm).

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the mass spectrometer in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(C)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. For unknown gas components that have similar analytical mass fragments to calibration compounds, you may report the unknowns as an increase in the overlapped calibration gas compound. For unknown compounds that produce mass fragments that do not overlap calibration compounds, you may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component. You may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.

(*5*) You must perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

(*6*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published value for the net heating value per mole at 25 °C and 1 atmosphere and use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(D) A grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours. Subsequent compositional analysis of the samples must be performed according to ASTM D1945–14 (R2019) or alternatively GPA 2261-19 (incorporated by reference, see § 60.17). To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published value for the net heating value per mole at 25 °C and 1 atmosphere and use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(iii) As an alternative to the continuous composition monitoring requirements in paragraph (d)(8)(ii) of this section, a sampling demonstration may be used as specified in this paragraph. Flares or enclosed combustion devices that are not required to monitor flare gas composition because the inlet gas streams to the flare or enclosed combustion device does not include streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.*, vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), are not required to conduct sampling demonstrations specified in this paragraph. For an unassisted or pressure-assisted flare or enclosed combustion device, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B) or (C), continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For flares and enclosed combustion devices that use assist air (including perimeter assist air) or assist steam, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds 300 Btu/scf, continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For an unassisted or pressure-assisted flare or enclosed combustion device, in lieu of conducting the demonstration outlined in paragraphs (d)(8)(iii)(A) through (D) of this section, you may conduct the demonstration outlined in paragraph (d)(8)(iii)(H) of this section, but you must still comply with paragraphs (d)(8)(iii)(E) through (G) of this section.

(A) Continuously monitor the inlet stream which is routed to the flare or enclosed combustion device for 14 operating days or collect a sample of the inlet gas which is routed to the enclosed combustion device or flare twice daily to determine the average NHV of the gas stream for 14 operating days with no sampling day to be spaced more than 3 operating days apart from the previous sampling day. If you do not continuously monitor the NHV, the minimum time of collection for each individual sample be at least one hour when technically feasible. When it is not technically feasible to collect individual samples for at least one hour (*e.g.*, low or intermittent flow), the collection time must be as long as possible up to one hour. For samples taken during low or intermittent flow events, the collection time and the reason for not obtaining a full one hour sample must be documented and reported with the NHV sampling results. Samples must be separated by at least 6 hours. If inlet gas flow is intermittent such that there are not at least 28 samples over the 14 operating day period, you must continue to collect samples of the inlet gas beyond the 14 operating day period until you collect a minimum of 28 samples.

(B) If you collect samples twice per day, count the number of samples where the NHV value is less than 1.2 times the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (C), or this paragraph (d)(8)(iii) (i.e., values that are less than 240, 360, or 960 Btu/scf, as applicable) during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(C) If you continuously sample the inlet stream for 14 days, count the number of hourly block average (*e.g.*, noon to 1 pm, 1 pm to 2 pm, etc.) NHV values that are less than the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), § 60.5415b(f)(1)(vii)(C), or this paragraph (d)(8)(iii) (*i.e.*, values that are less than 200, 300, or 800 Btu/scf, as applicable), during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(D) If there are no samples counted under paragraph (d)(8)(iii)(B) of this section or there are no hourly block average values counted under paragraph (d)(8)(iii)(C) of this section, the gas stream is considered to consistently exceed the applicable NHV operating limit and on-going continuous monitoring is not required.

(E) If process operations are revised that could reduce the NHV of the gas sent to the enclosed combustion device or flare, such as the removal or addition of process equipment, and at any time the Administrator requires, re-evaluation of the gas stream must be performed according to paragraphs (d)(8)(iii)(A) through (D) of this section within 60 days of the revisions to process operations to ensure the gas stream still consistently exceeds the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (C)(*1*), or this paragraph (d)(8)(iii). If any of the samples counted under paragraph (d)(8)(iii)(B) of this section or any hourly block average values counted under paragraph (d)(8)(iii)(C) of this section are less than the limits in the respective paragraph you must conduct the continuous monitoring required by one of the options paragraphs (d)(8)(ii)(A) through (D) of this section within 60 days of the re-evaluation of the gas stream.

(F) When collecting samples under paragraph (d)(8)(iii)(A) of this section, the owner or operator must account for any sources of inert gases or other vent gas streams which may lower the NHV of the combined stream (*e.g.*, vent streams from AGR system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers, vent streams from compressors in acid gas service, vent streams from enhanced oil recovery facilities, or vent streams from storage vessel with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV) that can be sent to the enclosed combustion device or flare. The owner or operator must document in the report in § 60.5420b(b)(11)(v)(I) and the records in § 60.5420b(c)(11)(vi) must note the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams, and whether the sampling included periods where the highest percentage of inert gases or other vent gas streams which may lower the NHV of the combined stream were sent to the enclosed combustion device or flare. If the introduction of inerts or other vent gas streams which may lower the NHV of the combined stream is intermittent and does not occur during the initial demonstration, the introduction of inerts or other vent gas streams which may lower the NHV of the combined stream will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E). If conditions at the site did not allow sampling during periods where the introduction of inert gases or other vent gas streams which may lower the NHV of the combined stream was at the highest percentage possible, increasing the percentage of inerts will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E).

(G) You must collect three samples of the inlet gas to the enclosed combustion device or flare at least once every 5 years. The minimum time of collection for each individual sample must be at least one hour, when technically feasible. When it is not technically feasible to collect individual samples for at least one hour (*e.g.*, low or intermittent flow), the collection time must be as long as possible up to one hour. For samples taken during low or intermittent flow events, the collection time and the reason for not obtaining a full one hour sample must be documented and reported with the NHV sampling results. The samples must be taken during the period with the lowest expected NHV (*i.e.*, the period with the highest percentage of inerts or other vent gas streams which may lower the NHV of the combined stream). The first set of periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the last sample taken under paragraph (d)(8)(iii)(A) of this section. Subsequent periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the previous sample. If any sample taken in accordance with this paragraph has an NHV value less than 1.2 times the applicable operating limit specified in § 60.5415b(f)(1)(vii)(B), (C), or paragraph (d)(8)(iii) (*i.e.*, values that are less than 240, 360, or 960 Btu/scf, as applicable), you must conduct the continuous monitoring required by one of the options in paragraphs (d)(8)(ii)(A) through (D) of this section within 60 days of receipt of the last sample.

(H) You may request an alternative test method under § 60.5412b(d) to demonstrate that the flare or enclosed combustion device reduces methane and VOC in the gases vented to the device by 95.0 percent by weight or greater. You must use an alternative test method that demonstrates compliance with the combustion efficiency limit; you may not use an alternative test method that demonstrates compliance with NHV_{cz} and NHV_{dil} in lieu of measuring combustion efficiency directly. You must measure data values at the frequency specified in the alternative test method and conduct the quality assurance and quality control requirements outlined in the alternative test method at the frequency outlined in the alternative test method. You must monitor the combustion efficiency of the flare continuously for 14 days. If there are no values of the combustion efficiency measured by the alternative test method that are less than 95.0 percent, the gas stream is considered to consistently exceed the applicable NHV operating limit, and you are not required to continuously monitor the NHV of the inlet gas to the flare or enclosed combustion device.

(iv) Except as noted in paragraphs (d)(8)(iv)(A) through (F) and (vi) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustion device or flare. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as inlet line pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate.

(A) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(B) Unassisted flares are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(B)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(C) Unassisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(C)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustion device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustion device cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section to be exceeded. If there are changes to the process or control device that can be reasonably expected to impact the maximum flow rate to the enclosed combustion device, you must conduct a new demonstration to determine whether the maximum flow rate to the enclosed combustor is less than the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section.

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(D) Air-assisted flares or enclosed combustion devices that use only perimeter assist air and have no assist steam or premix assist air are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist air if you meet the conditions in paragraphs (d)(8)(iv)(D)(*1*) through (*3*) of this section, as applicable. For these flares and enclosed combustion devices, NHV_{cz} is assumed to be equal to the vent gas NHV.

(*1*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(*2*) If you are required to monitor vent gas composition for the flare or enclosed combustion device according to paragraph (d)(8)(ii) or (iii) of this section, you must demonstrate, based on the maximum flow rate of perimeter assist air to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{dil} can never be less than the minimum required NHV_{dil}. The demonstration must clearly document why the maximum flow rate of perimeter assist air will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of perimeter assist air. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(*3*) For air-assisted flares, you must also demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(E) Air-assisted flares or enclosed combustion devices that use only premix assist air and have no assist steam or perimeter assist air are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist air if you meet the conditions in paragraphs (d)(8)(iv)(E)(*1*) through (*3*) of this section, as applicable.

(*1*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(*2*) If you are required to monitor vent gas composition for the flare or enclosed combustion device according to paragraph (d)(8)(ii) or (iii) of this section, you must demonstrate, based on the maximum flow rate of premix assist air to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{cz} will never be less than the minimum required NHV_{cz}. The demonstration must clearly document why the maximum flow rate of premix assist air will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve in and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of premix assist air. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(*3*) For air-assisted flares, you must also demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(F) Steam-assisted flares or enclosed combustion devices that have no premix assist air and or perimeter assist air (other than perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter of the flare tip is 9 inches or greater) are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device or the flow of assist steam if you meet the conditions in paragraphs (d)(8)(iv)(F)(*1*) through (*3*) of this section, as applicable.

(*1*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(*2*) If you are required to monitor vent gas composition for the flare or enclosed combustion device according to paragraph (d)(8)(ii) or (iii) of this section, you must demonstrate, based on the maximum flow rate of assist steam to the enclosed combustion device or flare and applicable engineering calculations, that the NHV_{cz} will never be less than the minimum required NHV_{cz}. The demonstration must clearly document why the maximum flow rate of assist steam will never exceed the rate used in the demonstration. You must use the minimum flow rate of vent gas allowed by your backpressure regulator valve in and the minimum expected value of the NHV of the inlet gas to the enclosed combustion device or flare based on previous sampling results or process knowledge of the streams sent to the enclosed combustion device or flare in your demonstration. You must update this demonstration if there are changes to the backpressure regulator valve, the backpressure regulator valve set point, or the maximum flow rate of assist steam. You must also update this demonstration if any sampling results of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(ii) or (iii) of this section are lower than the NHV vent gas value used in your demonstration.

(*3*) For steam-assisted flares, you must also demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(v) Conduct inspections monthly and at other times as requested by the Administrator to monitor for visible emissions from the combustion device using section 11 of Method 22 of appendix A of this part or conduct visible emissions monitoring according to paragraph (h) of this section. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period.

(vi) If you use a flare or enclosed combustion device that is air-assisted or steam-assisted and that receives streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.*, vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), you must either meet the applicable requirements in (d)(8)(vi)(A) through (D) of this section or you must use an approved alternative method allowed under § 60.5412b(d)(1)(i) and (ii) to continuously monitor NHV_{cz} and, if applicable, NHV_{dil}. If you elect to continuously monitor NHV_{cz} and, if applicable, NHV_{dil} using an approved alternative method as provided under § 60.5412b(d)(1)(i) and (ii), you are not required to monitor NHV of the vent gas as specified in paragraph (d)(8)(ii) of this section or monitor flow rates as specified in paragraph (d)(8)(vi) of this section provided you can demonstrate that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration.

(A) Except as allowed by paragraph (d)(8)(iv)(E) or (F) of this section, you must monitor and calculate NHV_{cz} as specified in § 63.670(m) of this chapter. Additionally, for flares and enclosed combustion devices that use only perimeter assist air and do not use steam assist or premix assist air, the NHV_{cz} is equal to the vent gas NHV. When NHV_{cz} is equal to the vent gas NHV, you are not required to continuously monitor NHV_{cz} if you meet the requirements in paragraph (d)(8)(iii) of this section.

(B) Except as allowed by paragraph (d)(8)(iv)(D) of this section, for each flare using perimeter assist air, you must also monitor and calculate NHV_{dil} as specified in § 63.670(n) of this chapter. If the only assist air provided to the flare or enclosed combustion control device is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, you are only required to comply with the NHV_{cz} limit specified in paragraph (f)(8)(vi)(A) of this section.

(C) Except as allowed by paragraph (d)(8)(iv) of this section, you must monitor the flare vent gas and assist gas as specified in § 63.670(i) of this chapter.

(D) You must determine the flare vent gas net heating value as specified in § 63.670(l) of this chapter using one of the methods specified in paragraph (d)(8)(ii) of this section. Where the phrase "petroleum refinery" is used, for purposes of this subpart, it will refer to flares controlling an affected facility under this subpart. If you are not required to continuously monitor the NHV of the inlet gas because you have demonstrated that it consistently exceeds the applicable operating limit as provided in paragraph (d)(8)(iii) of this section, you must use the lowest net heating value measured in the sampling program in paragraph (d)(8)(iii) of this section for the calculations performed in paragraphs (d)(8)(vi)(A) and (B). You must update this value if a subsequent sampling result of the NHV of the inlet gas to the enclosed combustion device or flare under paragraph (d)(8)(iii) of this section is lower than the NHV vent gas value used in your calculations.

*   *   *   *   *

(g)   *   *   *

(1) A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is below the applicable limits specified in § 60.5415b(f)(1)(vii)(B)(*1*) through (*4*) and (*6*) or above the limit specified in § 60.5415b(f)(1)(vii)(B)(*5*); or for each flare or enclosed combustion device except for boilers and process heaters meeting the requirements in § 60.5412b(a)(1)(iii) and catalytic vapor incinerators meeting the requirements in § 60.5412b(a)(1)(v), when the heat sensing device indicates that there is no pilot or combustion flame present for any time period. If you use a backpressure regulator valve to maintain the inlet gas flow to an enclosed combustion device or flare above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not fully close when not in the open position.

*   *   *   *   *

5. Amend § 60.5420b by revising paragraphs (a)(4), (b), (c)(3) through (6), (c)(11) through (15), and paragraph (d) to read as follows:

§ 60.5420b   What are my notification, reporting, and recordkeeping requirements?

(a)   *   *   *

(4) An owner or operator who commences well closure activities must submit the following notices to the Administrator according to the schedule in paragraphs (a)(4)(i)

and (ii) of this section. The notification shall include contact information for the owner or operator; the United States Well Number; 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. You must submit notifications in portable document format (PDF) following the procedures specified in paragraph (d) of this section.

(i) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site.

(ii) You must submit a notification of the intent to close a well site 60 days before you begin well closure activities.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (14) of this section following the procedure specified in paragraph (b)(15) of this section. You must submit performance test reports as specified in paragraph (b)(12) or (13) of this section, if applicable. Subject to the exception in the next sentence, the initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410b; subsequent annual reports are due no later than the same date each year as the initial annual report. Notwithstanding the preceding sentence, no annual report is due before November 30, 2026, on or before which date you must submit all annual reports that were due before November 30, 2026, per the timing specified in the preceding sentence; then subsequent annual reports thereafter are due no later than 90 days after the end of each annual compliance period. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (14) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period. You must submit the information in paragraph (b)(1)(v) of this section, as applicable, for your well affected facility which undergoes a change of ownership during the reporting period, regardless of whether reporting under paragraphs (b)(2) through (4) of this section is required for the well affected facility.

(1) The general information specified in paragraphs (b)(1)(i) through (v) of this section is required for all reports.

(i) The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (b)(1)(iv).

(v) Identification of each well affected facility for which ownership changed due to sale or transfer of ownership including the United States Well Number; the latitude and longitude coordinates of the well affected facility in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the information in paragraph (b)(1)(v)(A) or (B) of this section, as applicable.

(A) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator to which you sold or transferred ownership of the well affected facility identified in this paragraph (b)(1)(v).

(B) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator from whom you acquired the well affected facility identified in this paragraph (b)(1)(v).

(2) For each well affected facility that is subject to § 60.5375b(a) or (f), the records of each well completion operation conducted during the reporting period, including the information specified in paragraphs (b)(2)(i) through (xiv) of this section, if applicable. In lieu of submitting the records specified in paragraphs (b)(2)(i) through (xiv) of this section, the owner or operator may submit a list of each well completion with hydraulic fracturing completed during the reporting period, and the digital photograph required by paragraph (c)(1)(v) of this section for each well completion. For each well affected facility that routes all flowback entirely through one or more production separators, only the records specified in paragraphs (b)(2)(i) through (iv) and (vi) of this

section are required to be reported. For periods where salable gas is unable to be separated, the records specified in paragraphs (b)(2)(iv) and (viii) through (xii) of this section must also be reported, as applicable. For each well affected facility that is subject to § 60.5375b(g), the record specified in paragraph (b)(2)(xv) of this section is required to be reported. For each well affected facility which makes a claim that the exemption in § 60.5375b(h) was met, the records specified in paragraph (b)(2)(i) through (iv) and (xvi) of this section are required to be reported.

(i) Well Completion ID.

(ii) Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983.

(iii) U.S. Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production.

(v) The date and time of each attempt to direct flowback to a separator as required in § 60.5375b(a)(1)(ii).

(vi) The date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production.

(vii) The duration (in hours) of flowback.

(viii) The duration (in hours) of recovery and disposition of recovery (*i.e.*, routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(ix) The duration (in hours) of combustion.

(x) The duration (in hours) of venting.

(xi) The specific reasons for venting in lieu of capture or combustion.

(xii) For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation.

(xiii) For each well affected facility subject to § 60.5375b(f), a record of the well type (*i.e.*, wildcat well, delineation well, or low pressure well (as defined § 60.5430b)) and supporting inputs and calculations, if applicable.

(xiv) For each well affected facility for which you claim an exception under § 60.5375b(a)(2), the specific exception claimed and reasons why the well meets the claimed exception.

(xv) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, the supporting analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field.

(xvi) For each well affected facility which meets the exemption in § 60.5375b(h), a statement that the well completion operation requirements of § 60.5375b(a)(1) through (3) were met.

(3) For each well affected facility that is subject to § 60.5376b(a)(1) or (2), your annual report is required to include the information specified in paragraphs (b)(3)(i) and (ii) of this section, as applicable.

(i) For each well affected facility where all gas well liquids unloading operations comply with § 60.5376b(a)(1), your annual report must include the information specified in paragraphs (b)(3)(i)(A) through (C) of this section, as applicable.

(A) Identification of each well affected facility (U.S. Well ID or U.S. Well ID associated with the well affected facility) that conducts a gas well liquid unloading operation during the reporting period using a method that does not vent to the atmosphere and the technology or technique used. If more than one non-venting technology or technique is used, you must identify all of the differing non-venting liquids unloading methods used during the reporting period.

(B) Number of gas well liquids unloading operations conducted during the year where the well affected facility identified in (b)(3)(i)(A) had unplanned venting to the atmosphere and best management practices were conducted according to your best management practice plan, as required by § 60.5376b(c). If no venting events occurred, the number would be zero. Other reported information required to be submitted where unplanned venting occurs is specified in paragraphs (b)(3)(i)(B)(*1*) and (*2*) of this section.

(*1*) Log of best management practice plan steps used during the unplanned venting to minimize emissions to the maximum extent possible.

(*2*) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(C) The number of liquids unloading events where unplanned emissions are vented to the atmosphere during a gas well liquids unloading operation where you complied with best management practices to minimize emissions to the maximum extent possible.

(ii) For each well affected facility where all gas well liquids unloading operations comply with § 60.5376b(b) and (c) best management practices, your annual report must include the information specified in paragraphs (b)(3)(ii)(A) through (E) of this section.

(A) Identification of each well affected facility that conducts a gas well liquids unloading during the reporting period.

(B) Number of liquids unloading events conducted during the reporting period.

(C) Log of best management practice plan steps used during the reporting period to minimize emissions to the maximum extent possible.

(D) The number of liquids unloading events during the year that best management practices were conducted according to your best management practice plan.

(E) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(4) For each associated gas well subject to § 60.5377b, your annual report is required to include the applicable information specified in paragraphs (b)(4)(i) through (vi) of this section, as applicable.

(i) For each associated gas well that complies with § 60.5377b(a)(1), (2), (3), or (4) your annual report is required to include the information specified in paragraphs (b)(4)(i)(A) and (B) of this section.

(A) An identification of each associated gas well constructed, modified, or reconstructed during the reporting period that complies with § 60.5377b(a)(1), (2), (3), or (4).

(B) The information specified in paragraphs (b)(4)(i)(B)(*1*) through (*4*) of this section for each incident when the associated gas was temporarily routed to a flare or control device in accordance with § 60.5377b(d).

(*1*) The reason in § 60.5377b(d)(1), (2), (3), or (4) for each incident.

(2) The start date and time of each incident of routing associated gas to the flare or control device, along with the total duration in hours of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411b(a) and (c) and all applicable flare or control device requirements specified in § 60.5412b were met during each period when the associated gas is routed to the flare or control device.

(*4*) For each instance where you route associated gas to a flare or control device beyond 72 hours due to "exigent circumstances" according to § 60.5377b(d)(1) or (2), you must include the record information specified in paragraph (c)(3)(v) of this section in your annual report.

(ii) For all instances where you temporarily vent the associated gas in accordance with § 60.5377b(e), you must report the information specified in paragraphs (b)(4)(ii)(A) through (D) of this section. This information is required to be reported if you are routinely complying with § 60.5377b(a) or (f) or temporarily complying with § 60.5377b(d). In addition to this information for each incident, you must report the cumulative duration in hours of venting incidents and the cumulative VOC and methane emissions in pounds for all incidents in the calendar year.

(A) The reason in § 60.5377b(e)(1), (2), or (3) for each incident.

(B) The start date and time of each incident of venting the associated gas, along with the total duration in hours of each incident.

(C) The VOC and methane emissions in pounds that were emitted during each incident.

(D) The total duration of venting for all incidents in the year, along with the cumulative VOC and methane emissions in pounds that were emitted.

(iii) For each associated gas well that complies with the requirements of § 60.5377b(f) your annual report must include the information specified in paragraphs (b)(4)(iii)(A) through (E) of this section. The information in paragraphs (b)(4)(iii)(A) and (B) of this section is only required in the initial annual report.

(A) An identification of each associated gas well that commenced construction between May 7, 2024, and May 7, 2026. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(B) An identification of each associated gas well that commenced construction between December 6, 2022, and May 7, 2024. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(C) An identification of each associated gas well modified or reconstructed during the reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent. This identification must include the certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(D) For each associated gas well that was constructed, modified or reconstructed in a previous reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent, a re-certification of why it is infeasible to comply with § 60.5377b(a)(1), (2), (3), or (4) in accordance with § 60.5377b(g).

(E) The information specified in paragraphs (b)(11)(i) through (iv) of this section.

(iv) If you comply with § 60.5377b(f) with a control device, identification of the associated gas well using the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) For each deviation recorded as specified in paragraph (c)(3)(v) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(5) For each wet seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(i) through (v) of this section. For each self-contained wet seal centrifugal compressor, Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(vi) through (ix) of this section.

(i) An identification of each centrifugal compressor constructed, modified, or reconstructed during the reporting period.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(4) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) If required to comply with § 60.5380b(a)(2) or (3), the information specified in paragraphs (b)(11)(i) through (iv) of this section, as applicable.

(iv) If complying with § 60.5380b(a)(1) with a control device, identification of the centrifugal compressor with the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) If complying with § 60.5380b(a)(4), (5), or (6) for a self-contained wet seal centrifugal compressor, Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal centrifugal compressor requirements, the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate emissions measurement, as applicable, which have elapsed prior to conducting your volumetric flow rate emission measurement or emissions screening.

(vii) A description of the method used and the results of the volumetric emissions measurement or emissions screening, as applicable.

(viii) Number and type of seals on delay of repair and explanation for each delay of repair.

(ix) Date of planned shutdown(s) that occurred during the reporting period if there are any seals that have been placed on delay of repair.

(6) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(6)(i) through (vii) of this section, as applicable.

(i) The cumulative number of hours of operation since initial startup, since May 7, 2024, since the previous volumetric flow rate measurement, or since the previous reciprocating compressor rod packing replacement, as applicable, which have elapsed prior to conducting your volumetric flow rate measurement or emissions screening. Alternatively, a statement that emissions from the rod packing are being routed to a process or control device through a closed vent system.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(5)(i) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(iv) If complying with § 60.5385b(d)(1) or (2), the information in paragraphs (b)(11)(i) through (iv) of this section. If complying by routing emissions to a control device, as required in § 60.5385b(d)(2), the information in paragraph (b)(11)(v) of this section.

(v) Number and type of rod packing replacements/repairs on delay of repair and explanation for each delay of repair.

(vi) Date of planned shutdown(s) that occurred during the reporting period if there are any rod packing replacements/repairs that have been placed on delay of repair.

(vii) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(7) For each process controller affected facility, the information specified in paragraphs (b)(7)(i) through (iii) of this section in your initial annual report and in subsequent annual reports for each process controller affected facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(7)(iv) through (x) of this section for each process controller affected facility.

(i) An identification of each process controller that is driven by natural gas, as required by § 60.5390b(d), that allows traceability to the records required in paragraph (c)(6)(i) of this section.

(ii) For each process controller in the affected facility complying with § 60.5390b(a), you must report the information specified in paragraphs (b)(7)(ii)(A) and (B) of this section, as applicable.

(A) An identification of each process controller complying with § 60.5390b(a) by routing the emissions to a process.

(B) An identification of each process controller complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller.

(iii) For each process controller affected facility located at a site in Alaska that does not have access to electrical power and that complies with § 60.5390b(b), you must report the information specified in paragraph (b)(7)(iii)(A), (B), or (C) of this section, as applicable.

(A) For each process controller complying with § 60.5390b(b)(1) process controller bleed rate requirements, you must report the information specified in paragraphs (b)(7)(iii)(A)(*1*) and (*2*) of this section.

(*1*) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(*2*) Where necessary to meet a functional need, the identification and demonstration why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(B) An identification of each intermittent vent process controller complying with the requirements in paragraph § 60.5390b(b)(2).

(C) An identification of each process controller complying with the requirements in § 60.5390b(b) by routing emissions to a control device in accordance with § 60.5390b(b)(3).

(iv) Identification of each process controller which changes its method of compliance during the reporting period and the applicable information specified in paragraphs (b)(7)(v) through (ix) of this section for the new method of compliance.

(v) For each process controller in the affected facility complying with the requirements of § 60.5390b(a) by routing the emissions to a process, you must report the information specified in (b)(11)(i) through (iii) of this section.

(vi) For each process controller in the affected facility complying with the requirements of § 60.5390b(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (b)(7)(vi)(A) and (B) of this section.

(A) Dates of each inspection required under § 60.5416b(b); and

(B) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and the date of repair or date of anticipated repair if repair is delayed.

(vii) For each process controller in the affected facility complying with the requirements of § 60.5390b(b)(2), you must report the information specified in paragraphs (b)(7)(vii)(A) and (B) of this section.

(A) Dates and results of the intermittent vent process controller monitoring required by § 60.5390b(b)(2)(ii).

(B) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement or the date of anticipated repair or replacement if the repair or replacement is delayed, and the date and results of the re-survey after repair or replacement.

(viii) For each process controller affected facility complying with § 60.5390b(b)(3) by routing emissions to a control device, you must report the information specified in paragraph (b)(11) of this section.

(ix) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(x) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(7)(vi) and (vii) and (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(8) For each storage vessel affected facility, the information in paragraphs (b)(8)(i) through (x) of this section.

(i) An identification, including the location, of each storage vessel affected facility, including those for which construction, modification, or reconstruction commenced during the reporting period, and those provided in previous reports. The location of the storage vessel affected facility shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the methane and VOC emission rate determination according to § 60.5365b(e)(1) for each tank battery that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(7)(iii) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iv) For each storage vessel affected facility constructed, modified, reconstructed, or returned to service during the reporting period complying with § 60.5395b(a)(2) with a control device, report the identification of the storage vessel affected facility with the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(vi) If required to comply with § 60.5395b(b)(1), the information in paragraphs (b)(11)(i) through (iv) of this section.

(vii) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395b(c)(1)(ii), including the date the storage vessel affected facility was removed from service. You must identify each storage vessel that that is removed from service from a storage vessel affected facility during the reporting period as specified in § 60.5395b(c)(2)(iii), including identifying the impacted storage vessel affected facility and the date each storage vessel was removed from service.

(viii) You must identify each storage vessel affected facility or portion of a storage vessel affected facility returned to service during the reporting period as specified in § 60.5395b(c)(4), including the date the storage vessel affected facility or portion of a storage vessel affected facility was returned to service.

(ix) You must identify each storage vessel affected facility that no longer complies with § 60.5395b(a)(3) and instead complies with § 60.5395b(a)(2). You must identify whether the change in the method of compliance was due to fracturing or refracturing or whether the change was due to an increase in the monthly emissions determination. If the change was due to an increase in the monthly emissions determination, you must provide documentation of the emissions rate. You must identify the date that you complied with § 60.5395b(a)(2) and must submit the information in (b)(8)(iii) through (vii) of this section.

(x) You must submit a statement that you are complying with § 60.112b(a)(1) or (2), if applicable, in your initial annual report.

(9) For the fugitive emissions components affected facility, report the information specified in paragraphs (b)(9)(i) through (v) of this section, as applicable.

(i)(A) Designation of the type of site (*i.e.*, well site, centralized production facility, or compressor station) at which the fugitive emissions components affected facility is located.

(B) For the fugitive emissions components affected facility at a well site or centralized production facility that became an affected facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For the fugitive emissions components affected facility at a compressor station that became an affected facility during the reporting period, you must include the date of startup or the date of modification.

(C) For the fugitive emissions components affected facility at a well site, you must specify what type of well site it is (*i.e.*, single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment).

(D) For the fugitive emissions components affected facility at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For the fugitive emissions components affected facility at a well site where you previously reported under paragraph (b)(9)(i)(D) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(F) For the fugitive emissions components affected facility at a well site where during the reporting period you undertake well closure requirements, the date of the cessation of production from all wells at the well site, the date you began well closure activities at the well site, and the dates of the notifications submitted in accordance with paragraph (a)(4) of this section.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(9)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument or, if the survey was conducted by AVO methods, notation that AVO was used.

(C) Any deviations from the monitoring plan elements under § 60.5397b(c)(1), (2), and (7), (c)(8)(i), or (d) or a statement that there were no deviations from these elements of the monitoring plan.

(D) Number and type of components for which fugitive emissions were detected.

(E) Number and type of fugitive emissions components that were not repaired as required in § 60.5397b(h).

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

(G) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(iii) For the fugitive emissions components affected facility complying with an alternative fugitive emissions standard under § 60.5399b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in paragraphs (b)(9)(iii)(A) through (C) of this section.

(A) The alternative standard with which you are complying.

(B) The site-specific reports specified by the specific alternative fugitive emissions standard, submitted in the format in which they were submitted to the state, local, or Tribal authority. If the report is in hard copy, you must scan the document and submit it as an electronic attachment to the annual report required in paragraph (b) of this section.

(C) If the report specified by the specific alternative fugitive emissions standard is not site-specific, you must submit the information specified in paragraphs (b)(9)(i) and (ii) of this section for each individual site complying with the alternative standard.

(iv) For well closure activities which occurred during the reporting period, the information in paragraphs (b)(9)(iv)(A) and (B) of this section.

(A) A status report with dates for the well closure activities schedule developed in the well closure plan. If all steps in the well closure plan are completed in the reporting period, the date that all activities are completed.

(B) If an OGI survey is conducted during the reporting period, the information in paragraphs (b)(9)(iv)(B)(*1*) through (*3*) of this section.

(*1*) Date of the OGI survey.

(*2*) Monitoring instrument used.

(*3*) A statement that no fugitive emissions were found, or if fugitive emissions were found, a description of the steps taken to eliminate those emissions, the date of the resurvey, the results of the resurvey, and the date of the final resurvey which detected no emissions.

(v) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(10) For each pump affected facility, the information specified in paragraphs (b)(10)(i) through (iv) of this section in your initial annual report and in subsequent

annual reports for each pump affected facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(10)(v) through (ix) of this section for each pump affected facility.

(i) The identification of each of your pumps that are driven by natural gas, as required by § 60.5393b(a) that allows traceability to the records required by paragraph (c)(15)(i) of this section.

(ii) For each pump affected facility for which there is a control device on site but it does not achieve a 95.0 percent emissions reduction, the certification that there is a control device available on site but it does not achieve a 95.0 percent emissions reduction required under § 60.5393b(b)(5). You must also report the emissions reduction percentage the control device is designed to achieve.

(iii) For each pump affected facility for which there is no control device or vapor recovery unit on site, the certification required under § 60.5393b(b)(6) that there is no control device or vapor recovery unit on site.

(iv) For each pump affected facility for which it is technically infeasible to route the emissions to a process or control device, the certification of technically infeasibility required under § 60.5393b(b)(7).

(v) For any pump affected facility which has previously reported as required under paragraph (b)(10)(i) through (iv) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pump affected facility and the date that the pump affected facility meets one of the change conditions described in paragraph (b)(10)(v)(A), (B), or (C) of this section.

(A) If you install a control device or vapor recovery unit, you must report that a control device or vapor recovery unit has been added to the site and that the pump affected facility now is required to comply with § 60.5393b(b)(2), (3) or (5), as applicable.

(B) If your pump affected facility previously complied with § 60.5393b(b)(2), (3) or (5) by routing emissions to a process or a control device and the process or control device is subsequently removed from the site or is no longer available such that there is no ability to route the emissions to a process or control device at the site, or that it is not technically feasible to capture and route the emissions to another control device or process located on site, report that you are no longer complying with the applicable requirements of § 60.5393b(b)(2), (3), or (5) and submit the information provided in paragraph (b)(10)(v)(B)(*1*) or (*2*) of this section.

(*1*) Certification that there is no control device or vapor recovery unit on site.

(*2*) Certification of the engineering assessment that it is technically infeasible to capture and route the emissions to another control device or process located on site.

(C) If any pump affected facility or individual natural gas-driven pump changes its method of compliance during the reporting period other than for the reasons specified in paragraphs (b)(10)(v)(A) and (B) of this section, identify the new compliance method for each natural gas-driven pump within the affected facility which changes its method of compliance during the reporting period and provide the applicable information specified in paragraphs (b)(10)(ii) through (iv) and (vi) through (viii) of this section for the new method of compliance.

(vi) For each pump affected facility complying with the requirements of § 60.5393b(a) or (b)(1) or (3) by routing the emissions to a process, you must report the information specified in paragraphs (b)(11)(i) through (iv) of this section.

(vii) For each pump affected facility complying with the requirements of § 60.5393b(b)(3) or (5) by routing the emissions to a control device, you must report the information required under paragraphs (b)(11)(i) through (v) of this section.

(viii) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(ix) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in § 60.5424b.

(11) For each well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, you must submit the information in paragraphs (b)(11)(i) through (v) of this section. For each reciprocating compressor, process controller, pump, storage vessel, or process unit equipment which uses a closed vent system to route to a process, you must submit the information in paragraphs (b)(11)(i) through (iv) of this section. For each centrifugal

compressor, reciprocating compressor, and storage vessel equipped with a cover, you must submit the information in paragraphs (b)(11)(i) and (ii) of this section.

(i) Dates of each inspection required under § 60.5416b(a) and (b).

(ii) Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

(iii) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416b(a)(4).

(iv) You must submit the certification signed by the qualified professional engineer or in-house engineer according to § 60.5411b(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

(v) If you comply with the emissions standard for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment affected facility with a control device, the information in paragraphs (b)(11)(v)(A) through (L) of this section, unless you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d). If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), the information in paragraphs (b)(11)(v)(A) through (C) and (L) through (P) of this section.

(A) Identification of the control device.

(B) Make, model, and date of installation of the control device.

(C) Identification of the affected facility controlled by the device.

(D) For each continuous parameter monitoring system used to demonstrate compliance for the control device, a unique continuous parameter monitoring system identifier and the make, model number, and date of last calibration check of the continuous parameter monitoring system.

(E) For each instance where there is a deviation of the control device in accordance with § 60.5417b(g)(1) through (3) or (g)(5) through (7) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.*, NHV operating limit, lack of pilot or combustion flame, condenser efficiency, bypass line flow, visible emissions), and cause of the deviation.

(F) For each instance where there is a deviation of the continuous parameter monitoring system in accordance with § 60.5417b(g)(4) include the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(G) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test or observation of the video surveillance output, the length of the observation in minutes, and the number of minutes for which visible emissions were present.

(H) If a performance test was conducted on the control device during the reporting period, provide the date the performance test was conducted. Submit the performance test report following the procedures specified in paragraph (b)(12) of this section.

(I) An indication of whether the enclosed combustion device or flare receives inert gases or other vent streams which may lower the NHV of the combined stream, and if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams. If a demonstration of the NHV of the inlet gas to the enclosed combustion device or flare was conducted during the reporting period in accordance with § 60.5417b(d)(8)(iii), an indication of whether this is a re-evaluation of vent gas NHV and the reason for the re-evaluation; the applicable required minimum vent gas NHV; if twice daily samples of the vent stream were taken, the number of samples with NHV values that are less than 1.2 times the applicable required minimum NHV, an indication of whether full one hour samples were collected or if shorter sampling times were used, and, if shorter sampling times were used, the collection time(s) used and the reason for not obtaining a full one hour sample; if continuous NHV sampling of the vent stream was conducted, the number of hourly block average NHV values that are less than the required minimum vent gas NHV; if continuous combustion efficiency monitoring was conducted using an alternative test method approved under § 60.5412b(d), the number of values of the combustion efficiency that were less than 95.0 percent; the resulting determination of whether continuous NHV monitoring is required or not in accordance with § 60.5417b(d)(8)(iii)(D), (E), or (H); and if the enclosed combustion device or flare received inert gases or other vent streams which may lower the NHV of the combined stream, whether the sampling included periods where the highest percentage of inert gases or other gases which may lower the NHV of the combined stream were sent to the enclosed combustion device or flare.

(J) If a demonstration was conducted in accordance with § 60.5417b(d)(8)(iv) that the maximum potential pressure of units manifolded to an enclosed combustion device or flare cannot cause the maximum inlet flow rate established in accordance with § 60.5417b(f)(1) or a flare tip velocity limit of 18.3 meter/second (60 feet/second) to be exceeded, an indication of whether this is a re-evaluation of the gas flow and the reason for the re-evaluation; the demonstration conducted; and applicable engineering calculations.

(K) For each periodic sampling event conducted under § 60.5417b(d)(8)(iii)(G), provide the date of the sampling, the required minimum vent gas NHV, and the NHV value for each vent gas sample.

(L) For each flare and enclosed combustion device, provide the date each device is observed with OGI in accordance with § 60.5415b(f)(1)(x) and whether uncombusted emissions were present. Provide the date each device was visibly observed during an AVO inspection in accordance with § 60.5415b(f)(1)(x), whether the pilot or combustion flame was lit at the time of observation, and whether the device was found to be operating properly.

(M) An identification of the alternative test method used.

(N) For each instance where there is a deviation of the control device in accordance with § 60.5417b(i)(6)(i) or (iii) through (v) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.*, NHV_{cz} operating limit, lack of pilot or combustion flame, visible emissions), and cause of the deviation.

(O) For each instance where there is a deviation of the data availability in accordance with § 60.5417b(i)(6)(ii) include the date of each operating day when monitoring data are not available for at least 75 percent of the operating hours.

(P) If no deviations occurred under paragraph (b)(11)(v)(N) or (O) of this section, a statement that there were no deviations for the control device during the annual report period.

(Q) Any additional information required to be reported as specified by the Administrator as part of the alternative test method approval under § 60.5412b(d).

(12) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413b(d), you must submit the results of the performance test following the procedures specified in paragraph (d) of this section. Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(13) For combustion control devices tested by the manufacturer in accordance with § 60.5413b(d), an electronic copy of the performance test results required by §

60.5413b(d) shall be submitted via email to Oil_and_Gas_PT@EPA.GOV unless the test results for that model of combustion control device are posted at the following website: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.

(14) If you had a super-emitter event during the reporting period, the start date of the super-emitter event, the duration of the super-emitter event in hours, and the affected facility associated with the super-emitter event, if applicable.

(15) You must submit your annual report using the appropriate electronic report template on the Compliance and Emissions Data Reporting Interface (CEDRI) website for this subpart and following the procedure specified in paragraph (d) of this section. If the reporting form specific to this subpart is not available on the CEDRI website at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

* * * * *

(c) * * *

(3) For each associated gas well, you must maintain the applicable records specified in paragraphs (c)(3)(i) or (ii) and (iii), (iv), (v) and (vi) of this section, as applicable.

(i) For each associated gas well that complies with the requirements of § 60.5377b(a)(1), (2), (3), or (4), you must keep the records specified in paragraphs (c)(3)(i)(A) and (B).

(A) Documentation of the specific method(s) in § 60.5377b(a)(1), (2), (3), or (4) that is used.

(B) For instances where you temporarily route the associated gas to a flare or control device in accordance with § 60.5377b(d), you must keep the records specified in paragraphs (c)(3)(i)(B)(*1*) through (*3*).

(*1*) The reason in § 60.5377b(d)(1), (2), (3), or (4) for each incident.

(2) The date of each incident, along with the times when routing the associated gas to the flare or control device started and ended, along with the total duration of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411b(a) and (c) and all applicable flare or control device requirements specified in § 60.5412b are met during each period when the associated gas is routed to the flare or control device.

(ii) For instances where you temporarily vent the associated gas in accordance with § 60.5377b(e), you must keep the records specified in paragraphs (c)(3)(ii)(A) through (D) of this section. These records are required if you are routinely complying with § 60.5377b(a) or § 60.5377b(f) or temporarily complying with § 60.5377b(d).

(A) The reason in § 60.5377b(e)(1), (2), or (3) for each incident.

(B) The date of each incident, along with the times when venting the associated gas started and ended, along with the total duration of each incident.

(C) The VOC and methane emissions that were emitted during each incident.

(D) The cumulative duration of venting incidents and VOC and methane emissions for all incidents in each calendar year.

(iii) For each associated gas well that complies with the requirements of § 60.5377b(f) because it has demonstrated that it is not feasible to comply with § 60.5377b(a)(1) through (4) due to technical reasons in accordance with § 60.5377b(g), records of each annual demonstration and certification of the technical reason that it is not feasible to comply with § 60.5377b(a)(1) through (4) in accordance with § 60.5377b(g).

(iv) For each associated gas well that complies with the requirements of § 60.5377b(f), meet the recordkeeping requirements specified in paragraphs (c)(3)(iv)(A) through (E) of this section.

(A) Identification of each instance when associated gas was vented and not routed to a control device that reduces VOC and methane emissions by at least 95.0 percent.

(B) If you comply with the emission reduction standard in § 60.5377b with a control device, the information for each control device in paragraph (c)(11) and (13) of this section.

(C) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain records of the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(v) For each instance where you route associated gas to a flare or control device beyond 72 hours due to an "exigent circumstance" according to § 60.5377b(d)(1) or (2), you must maintain the records specified in paragraphs (c)(3)(v)(A) through (D) of this section.

(A) A written description of the "exigent circumstance" requiring the need to flare or route to a control device beyond 72 hours.

(B) A description of the steps taken to resolve the need for temporary flaring/routing to a control device;

(C) The dates and times an identified "exigent circumstance" started and ended (*e.g.*, when owners or operators are able to access site, when personnel and/or equipment are available) and the total duration of each "exigent circumstance"; and

(D) The dates and times temporary flaring/routing to a control device started and ended and the total duration of temporary flaring/routing to a control device due to the identified "exigent circumstance."

(vi) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(4) For each centrifugal compressor affected facility, you must maintain the records specified in paragraphs (c)(4)(i) through (iii) of this section.

(i) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380b, including a description of each deviation, the date and time each deviation began and the duration of each deviation.

(ii) For each wet seal compressor complying with the emissions reduction standard in § 60.5380b(a)(1), you must maintain the records in paragraphs (c)(4)(ii)(A) through (E) of this section. For each wet seal compressor complying with the alternative standard in § 60.5380b(a)(3) by routing the closed vent system to a process, you must maintain the records in paragraphs (c)(4)(ii)(B) through (E) of this section.

(A) If you comply with the emission reduction standard in § 60.5380b(a)(1) with a control device, the information for each control device in paragraph (c)(11) of this section.

(B) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain the information specified in § 60.5424b.

(C) Records of the cover inspections as specified in paragraph (c)(9) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(9) of this section, you must maintain the information specified in § 60.5424b.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(iii) For each centrifugal compressor affected facility using a self-contained wet seal compressor, centrifugal compressor equipped with sour seal oil separator and capture system, or dry seal compressor complying with the standard in § 60.5380b(a)(4), (5) or (6), you must maintain the records specified in paragraphs (c)(4)(iii)(A) through (H) of this section.

(A) Records of the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate measurement, as applicable.

(B) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(C) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(4)(iii)(C)(*1*) through (*6*).

(*1*) Description of standard method published by a consensus-based standards organization or industry standard practice.

(*2*) Records of volumetric flow rate emissions calculations conducted according to paragraphs § 60.5380b(a)(4) through (6), as applicable.

(*3*) Records of manufacturer's operating procedures and measurement methods.

(*4*) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration, and accuracy checks.

(*5*) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(*6*) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(D) Date when performance-based volumetric flow rate is exceeded.

(E) The date of successful repair of the compressor seal, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

(F) Identification of each compressor seal placed on delay of repair and explanation for each delay of repair.

(G) For each compressor seal or part needed for repair placed on delay of repair because of replacement seal or part unavailability, the operator must document: the date the seal or part was added to the delay of repair list, the date the replacement seal or part was ordered, the anticipated seal or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the seal or part.

(H) Date of planned shutdowns that occur while there are any seals or parts that have been placed on delay of repair.

(5) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(5)(i) through (x) and (c)(8) through (13) of this section, as applicable. If you comply with an alternative GHG and VOC standard under § 60.5398b,

in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(i) For each reciprocating compressor affected facility, you must maintain records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385b, including a description of each deviation, the date and time each deviation began and the duration of each deviation in hours.

(ii) Records of the date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5385b(d).

(iii) Records of the cumulative number of hours of operation since initial startup, since May 7, 2024, or since the previous volumetric flow rate measurement, as applicable. Alternatively, a record that emissions from the rod packing are being routed to a process through a closed vent system.

(iv) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(v) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(5)(v)(A) through (F).

(A) Description of standard method published by a consensus-based standards organization or industry standard practice.

(B) Records of volumetric flow rate calculations conducted according to § 60.5385b(b) or (c), as applicable.

(C) Records of manufacturer operating procedures and measurement methods.

(D) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration, and accuracy checks.

(E) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(F) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(vi) Date when performance-based volumetric flow rate is exceeded.

(vii) The date of successful replacement or repair of reciprocating compressor rod packing, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

(viii) Identification of each reciprocating compressor placed on delay of repair because of rod packing or part unavailability and explanation for each delay of repair.

(ix) For each reciprocating compressor that is placed on delay of repair because of replacement rod packing or part unavailability, the operator must document: the date the rod packing or part was added to the delay of repair list, the date the replacement rod packing or part was ordered, the anticipated rod packing or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the rod packing or part.

(x) Date of planned shutdowns that occur while there are any reciprocating compressors that have been placed on delay of repair due to the unavailability of rod packing or parts to conduct repairs.

(6) For each process controller affected facility, you must maintain the records specified in paragraphs (c)(6)(i) through (vii) of this section.

(i) Records identifying each process controller that is driven by natural gas and that does not function as an emergency shutdown device.

(ii) For each process controller affected facility complying with § 60.5390b(a), you must maintain records of the information specified in paragraphs (c)(6)(ii)(A) and (B) of this section, as applicable.

(A) If you are complying with § 60.5390b(a) by routing process controller vapors to a process through a closed vent system, you must report the information specified in paragraphs (c)(6)(ii)(A)(*1*) and (*2*) of this section.

(*1*) An identification of all the natural gas-driven process controllers in the process controller affected facility for which you collect and route vapors to a process through a closed vent system.

(*2*) The records specified in paragraphs (c)(8), (10), and (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(B) If you are complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (c)(6)(ii)(B)(*1*) through (*3*) of this section.

(*1*) An identification of each process controller complying with § 60.5390b(a) by using a self-contained natural gas-driven process controller;

(*2*) Dates of each inspection required under § 60.5416b(b); and

(*3*) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and date of repair or date of anticipated repair if repair is delayed.

(iii) For each process controller affected facility complying with the § 60.5390b(b)(1) process controller bleed rate requirements, you must maintain records of the information specified in paragraphs (c)(6)(iii)(A) and (B) of this section.

(A) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh and records of the manufacturer's specifications indicating that the process controller is designed with a natural gas bleed rate of less than or equal to 6 scfh.

(B) Where necessary to meet a functional need, the identification of the process controller and demonstration of why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(iv) For each intermittent vent process controller in the affected facility complying with the requirements in paragraphs § 60.5390b(b)(2), you must keep records of the information specified in paragraphs (c)(6)(iv)(A) through (C) of this section.

(A) The identification of each intermittent vent process controller.

(B) Dates and results of the intermittent vent process controller monitoring required by § 60.5390b(b)(2)(ii).

(C) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement, or the date of anticipated repair or replacement if the repair or replacement is delayed and the date and results of the re-survey after repair or replacement.

(v) For each process controller affected facility complying with § 60.5390b(b)(3), you must maintain the records specified in paragraphs (c)(6)(v)(A) and (B) of this section.

(A) An identification of each process controller for which emissions are routed to a control device.

(B) Records specified in paragraphs (c)(8) and (10) through (13) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(vi) Records of each change in compliance method, including identification of each natural gas-driven process controller which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(vii) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

*   *   *   *   *

(11) Records for each control device used to comply with the emission reduction standard in § 60.5377b(d) or (f) for associated gas wells, § 60.5380b(a)(1) or (9) for

centrifugal compressor affected facilities, § 60.5385b(d)(2) for reciprocating compressor affected facilities, § 60.5390b(b)(3) for your process controller affected facility in Alaska, § 60.5393b(b)(3) for your pump affected facility, § 60.5395b(a)(2) for your storage vessel affected facility, § 60.5376b(g) for well affected facility gas well liquids unloading, or § 60.5400b(f) or 60.5401b(e) for your process equipment affected facility, as required in paragraph (c)(11)(i) through (viii) of this section. If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), keep records of the information in paragraph (c)(11)(ix) of this section, in lieu of the records required by paragraphs (c)(11)(i) through (iv) and (vi) through (viii) of this section.

(i) For a control device tested under § 60.5413b(d) which meets the criteria in § 60.5413b(d)(11) and (e), keep records of the information in paragraphs (c)(11)(i)(A) through (E) of this section, in addition to the records in paragraphs (c)(11)(ii) through (ix) of this section, as applicable.

(A) Serial number of purchased device and copy of purchase order.

(B) Location of the affected facility associated with the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(C) Minimum and maximum inlet gas flow rate specified by the manufacturer.

(D) Records of the maintenance and repair log as specified in § 60.5413b(e)(4), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(ii) For all control devices, keep records of the information in paragraphs (c)(11)(ii)(A) through (G) of this section, as applicable.

(A) Make, model, and date of installation of the control device, and identification of the affected facility controlled by the device.

(B) Records of deviations in accordance with § 60.5417b(g)(1) through (7), including a description of the deviation, the date and time the deviation began, the duration of the deviation, and the cause of the deviation.

(C) The monitoring plan required by § 60.5417b(c)(2).

(D) Make and model number of each continuous parameter monitoring system.

(E) Records of minimum and maximum operating parameter values, continuous parameter monitoring system data (including records that the pilot or combustion flame is present at all times), calculated averages of continuous parameter monitoring system data, and results of all compliance calculations.

(F) Records of continuous parameter monitoring system equipment performance checks, system accuracy audits, performance evaluations, or other audit procedures and results of all inspections specified in the monitoring plan in accordance with § 60.5417b(c)(2). Records of calibration gas cylinders, if applicable.

(G) Periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities Records of repairs on the monitoring system.

(iii) For each carbon adsorption system, records of the schedule for carbon replacement as determined by the design analysis requirements of § 60.5413b(c)(2) and (3) and records of each carbon replacement as specified in §§ 60.5412b(c)(1) and 60.5415b(f)(1)(viii).

(iv) For enclosed combustion devices and flares, records of visible emissions observations as specified in paragraph (c)(11)(iv)(A) or (B) of this section.

(A) Records of observations with Method 22 of appendix A-7 to this part, including observations required following return to operation from a maintenance or repair activity, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in Method 22 of appendix A-7 to this part.

(B) If you monitor visible emissions with a video surveillance camera, location of the camera and distance to emission source, records of the video surveillance output, and documentation that an operator looked at the feed daily, including the date and start time of observation, the length of observation, and length of time visible emissions were present.

(v) For enclosed combustion devices and flares, video of the OGI inspection conducted in accordance with § 60.5415b(f)(1)(x). Records documenting each enclosed combustion device and flare was visibly observed during each inspection conducted under § 60.5397b using AVO in accordance with § 60.5415b(f)(1)(x).

(vi) For enclosed combustion devices and flares, an indication of whether the enclosed combustion device or flare receives inert gases or other vent streams which may lower the NHV of the combined stream, and if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams. Records of each demonstration of the NHV of the inlet gas to the enclosed combustion device or flare conducted in accordance with § 60.5417b(d)(8)(iii), including the sampling approach used (continuous NHV, twice daily sampling, alternative method), the date, time and results of each analysis, and, if shorter sampling times were used with twice daily sampling, the collection time(s) used and the reason for not obtaining a full one hour sample. For each re-evaluation of the NHV of the inlet gas, records of process changes and explanation of the conditions that led to the need to re-evaluation the NHV of the inlet gas. For each demonstration where the enclosed combustion device or flare received inert gases, record the highest percentage of inert gases that can be sent to the enclosed combustion device or flare and the highest percent of inert gases sent to the enclosed combustion device or flare during the NHV demonstration. Records of periodic sampling conducted under § 60.5417b(d)(8)(iii)(G).

(vii) For enclosed combustion devices and flares, if you use a backpressure regulator valve, the make and model of the valve, date of installation, and record of inlet flow rating. Maintain records of the engineering evaluation and manufacturer specifications that identify the pressure set point corresponding to the minimum inlet gas flow rate, the annual confirmation that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications, and the annual confirmation that the backpressure regulator valve fully closes when not in open position.

(viii) For enclosed combustion devices and flares, records of each demonstration required under § 60.5417b(d)(8)(iv).

(ix) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412b(d), keep records of the information in paragraphs (c)(11)(ix)(A) through (H) of this section, in lieu of the records required by paragraphs (c)(11)(i) through (iv) and (vi) through (viii) of this section.

(A) An identification of the alternative test method used.

(B) Data recorded at the intervals required by the alternative test method.

(C) Monitoring plan required by § 60.5417(i)(2).

(D) Quality assurance and quality control activities conducted in accordance with the alternative test method.

(E) If required by § 60.5412b(d)(4) to conduct visible emissions observations, records required by paragraph (c)(11)(iv) of this section.

(F) If required by § 60.5412b(d)(5) to conduct pilot or combustion flame monitoring, record indicating the presence of a pilot or combustion flame and periods when the pilot or combustion flame is absent.

(G) For each instance where there is a deviation of the control device in accordance with § 60.5417b(i)(6)(i) through (v), the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(H) Any additional information required to be recorded as specified by the Administrator as part of the alternative test method approval under § 60.5412b(d).

(12) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411b(c):

(i) A copy of the assessment conducted according to § 60.5411b(c)(1); and

(ii) A copy of the certification according to § 60.5411b(c)(1)(i) and (ii).

(13) A copy of each performance test submitted under paragraph (b)(12) or (13) of this section.

(14) For the fugitive emissions components affected facility, maintain the records identified in paragraphs (c)(14)(i) through (viii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for the fugitive emissions components affected facility at a well site and the date of startup or the date of modification for the fugitive emissions components affected facility at a compressor station.

(ii) For the fugitive emissions components affected facility at a well site, you must maintain records specifying what type of well site it is (i.e., single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment.)

(iii) For the fugitive emissions components affected facility at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

(iv) The fugitive emissions monitoring plan as required in § 60.5397b(b), (c), and (d).

(v) The records of each monitoring survey as specified in paragraphs (c)(14)(v)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument or method used.

(E) Fugitive emissions component identification when Method 21 of appendix A-7 to this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (i.e., operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

(G) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(H) Records of calibrations for the instrument used during the monitoring survey.

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(14)(v)(I)(*1*) through (*9*) of this section.

(*1*) Location of each fugitive emission identified.

(*2*) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(*3*) If Method 21 of appendix A-7 to this part is used for detection, record the component ID and instrument reading.

(*4*) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.*, tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(*5*) The date of first attempt at repair of the fugitive emissions component(s).

(*6*) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

(*7*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair.

(*8*) For each fugitive emission component placed on delay of repair for reason of replacement component unavailability, the operator must document: the date the component was added to the delay of repair list, the date the replacement fugitive component or part thereof was ordered, the anticipated component delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the component.

(*9*) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(vi) For the fugitive emissions components affected facility complying with an alternative means of emissions limitation under § 60.5399b, you must maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(vii) For well closure activities, you must maintain the information specified in paragraphs (c)(14)(vii)(A) through (G) of this section.

(A) The well closure plan developed in accordance with § 60.5397b(l) and the date the plan was submitted.

(B) The notification of the intent to close the well site and the date the notification was submitted.

(C) The date of the cessation of production from all wells at the well site.

(D) The date you began well closure activities at the well site.

(E) Each status report for the well closure activities reported in paragraph (b)(9)(iv)(A) of this section.

(F) Each OGI survey reported in paragraph (b)(9)(iv)(B) of this section including the date, the monitoring instrument used, and the results of the survey or resurvey.

(G) The final OGI survey video demonstrating the closure of all wells at the site. The video must include the date that the video was taken and must identify the well site location by latitude and longitude.

(viii) If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraphs (c)(14)(iv) and (v) of this section, you must maintain the records specified in § 60.5424b.

(15) For each pump affected facility, you must maintain the records identified in paragraphs (c)(15)(i) through (ix) of this section.

(i) Identification of each pump that is driven by natural gas and that is in operation 90 days or more per calendar year.

(ii) If you are complying with § 60.5393b(a) or (b)(1) by routing pump vapors to a process through a closed vent system, identification of all the pumps in the pump affected facility for which you collect and route vapors to a process through a closed vent system and the records specified in paragraphs (c)(8), (10), and (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(iii) If you are complying with § 60.5393b(b)(1) by routing pump vapors to control device achieving a 95.0 percent reduction in methane and VOC emissions, you must keep the records specified in paragraphs (c)(8) and (10) through (13) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398b, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424b.

(iv) If you are complying with § 60.5393b(b)(5) by routing pump vapors to control device achieving less than a 95.0 percent reduction in methane and VOC emissions, you must maintain records of the certification that there is a control device on site but it does not achieve a 95.0 percent emissions reduction and a record of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(v) If you have less than three natural gas-driven diaphragm pumps in the pump affected facility, and you do not have a vapor recovery unit or control device installed on site by the compliance date, you must retain a record of your certification required under § 60.5393b(b)(6), certifying that there is no vapor recovery unit or control device on site. If you subsequently install a control device or vapor recovery unit, you must maintain the records required under paragraph (c)(15)(ii), (iii) or (iv) of this section, as applicable.

(vi) If you determine, through an engineering assessment, that it is technically infeasible to route the pump affected facility emissions to a process or control device, you must retain records of your demonstration and certification that it is technically infeasible as required under § 60.5393b(b)(5).

(vii) If the pump is routed to a control device that is subsequently removed from the location or is no longer available such that there is no option to route to a control device, you are required to retain records of this change and the records required under paragraph (c)(15)(vi) of this section.

(viii) Records of each change in compliance method, including identification of each natural gas-driven pump which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(ix) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(d) *Electronic reporting.* If you are required to submit notifications or reports following the procedure specified in this paragraph (d), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (d)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA’s CDX as described earlier in this paragraph (d).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described above, should include clear CBI

markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Oil and Natural Gas Sector Lead. 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 email oaqpscbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. ERT files should be sent to the secondary attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the secondary attention of the Oil and Natural Gas Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

*   *   *   *   *

Subpart OOOOc—Emissions Guidelines for Greenhouse Gas Emissions From Existing Crude Oil and Natural Gas Facilities

6. Amend § 60.5391c by revising paragraphs (b) through (e) to read as follows:

§ 60.5391c   What GHG standards apply to associated gas wells at well designated facilities?

*   *   *   *   *

(b) If you meet one of the conditions in paragraph (b)(1) or (2) of this section, you may route the associated gas to a control device that reduces methane emissions by at least 95.0 percent instead of complying with paragraph (a) of this section. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411c(a) and (c) and the control device must meet the conditions specified in § 60.5412c(a) through (c).

(1) If the annual methane contained in the associated gas from your oil well is 40 tons per year or less at the initial compliance date, determined in accordance with paragraph (e) of this section.

(2) If you demonstrate and certify that it is not feasible to comply with paragraphs (a)(1) through (4) of this section due to technical reasons by providing a detailed analysis documenting and certifying the technical reasons for this infeasibility in accordance with paragraphs (b)(2)(i) through (iv) of this section.

(i) In order to demonstrate that it is not feasible to comply with paragraphs (a)(1) through (4) of this section, you must provide a detailed analysis documenting and certifying the technical reasons for this infeasibility. The demonstration must address the technical infeasibility for all options identified in paragraphs (a)(1) through (4). Documentation of these demonstrations must be maintained in accordance with § 60.5420c(c)(2)(iv).

(ii) This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer or other qualified individual shall state: “I certify that the assessment of technical and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of § 60.5391c(b)(2).

Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(iii) This demonstration and certification are valid for no more than 12 months. You must re-analyze the feasibility of complying with paragraphs (a)(1) through (4) of this section and finalize a new demonstration and certification each year.

(iv) Documentation of these demonstrations, along with the certifications, must be maintained in accordance with § 60.5420c(c)(2)(iv) and submitted in annual reports in accordance with § 60.5420c(b)(3).

(c) If you are complying with paragraph (a) of this section, you may temporarily route the associated gas to a flare or control device in the situations and for the durations identified in paragraph (c)(1), (2), (3), or (4) of this section. The associated gas must be routed through a closed vent system that meets the requirements of § 60.5411c(a) and (c) and the control device must meet the conditions specified in § 60.5412c. If you are routing to a flare, you must demonstrate that the § 60.18 flare requirements are met during the period when the associated gas is routed to the flare. Records must be kept of all temporary flaring instances in accordance with § 60.5420c(c)(2) and reported in the annual report in accordance with § 60.5420c(b)(3).

(1) During a malfunction or incident that endangers the safety of operator personnel or the public you are allowed to route associated gas to a flare or control device until the malfunction or incident is resolved but not longer than 72 hours per incident. Temporarily routing associated gas to a flare or control device is allowed only until the malfunction or incident is resolved. Notwithstanding the previous sentences, if there are

exigent circumstances that reasonably require routing to a flare or control device for more than 72 hours, paragraphs (c)(1)(i) through (iii) of this section apply.

(i) An “exigent circumstance” for purposes of paragraph (c)(1) of this section is a situation that results in the inability to reasonably access a site with the necessary equipment and personnel to address and resolve incidents that cause the need to temporarily flare associated gas for more than 72 hours. This includes circumstances where there is a need to flare beyond 72 hours due to an unexpected malfunction event and equipment needed to resolve an incident are not readily available due to an owner's or operator's inability to secure the required equipment for reasons beyond an owner's or operator’s control (*i.e.*, supply chain issues); or there is a temporary shortage of personnel needed to resolve an incident due to a circumstance such as a declared national pandemic that is beyond an owner's or operator's control.

(ii) Temporarily routing associated gas to a flare or control device is allowed until the malfunction or incident is resolved, but shall not be longer than 72 hours after the site can be accessed following the passing of the exigent circumstance.

(iii) For instances where you route associated gas to a flare or control device for more than 72 hours, you must meet the reporting requirements specified in § 60.5420c(b)(3)(i)(B)(*4*) and must maintain the records specified in § 60.5420c(c)(2)(vi).

(2) During repair and maintenance, including blow downs, a production test, or commissioning, you are allowed to route associated gas to a flare or control device until the incident is resolved, but not longer than 72 hours per incident. Temporarily routing associated gas to a flare or control device is allowed only until the incident is resolved. Notwithstanding the previous sentences, if there are exigent circumstances that

reasonably require routing to a flare or control device for more than 72 hours, paragraphs (c)(1)(i) through (iii) apply.

(3) For wells complying with paragraph (a)(1) of this section, for the duration of a temporary interruption in service from the gathering or pipeline system, or 30 days, whichever is less.

(4) For 72 hours from the time that the associated gas does not meet pipeline specifications, or until the associated gas meets pipeline specifications, whichever is less.

(d) If you are complying with paragraph (a), (b), or (c) of this section, you may vent the associated gas in the situations and for the durations identified in paragraph (d)(1), (2), or (3) of this section. Records must be kept of all venting instances in accordance with § 60.5420c(c)(2) and reported in the annual report in accordance with § 60.5420c(b)(3).

(1) For up to 12 hours to protect the safety of personnel.

(2) For up to 30 minutes during bradenhead monitoring.

(3) For up to 30 minutes during a packer leakage test.

(e) Calculate the methane content in associated gas as specified in paragraph (e)(1) of this section and comply with paragraphs (e)(2) and (3) of this section.

(1) Calculate the methane content in associated gas from your oil well using the following equation:

Equation 1 to paragraph (e)(1)

$$AG_{methane} = \frac{(GOR \times V \times M_{methane} \times 0.0192)}{907.2}$$

Where:
$AG_{methane}$ = Amount of methane in associated gas from the oil well, tons methane per year.

GOR = Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities. GOR is to be determined for the well using available data, an appropriate standard method published by a consensus-based standards organization which include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB), or in industry standard practice.
V = Volume of oil produced in the calendar year preceding the initial compliance date, in barrels per year.
$M_{methane}$ = mole fraction of methane in the associated gas.
0.0192 = density of methane gas at 60°F and 14.7 psia in kilograms per cubic foot.
907.2 = conversion of kilograms to tons, kilograms per ton.

(2) You must maintain records of the calculation of the methane in associated gas from your oil well results in accordance with § 60.5420c(c)(2), and submit the information, as well as the background information, in the next annual report in accordance with § 60.5420c(b)(3).

(3) If a process change occurs that could increase the methane content in the associated gas, you must recalculate the methane content in accordance with paragraph (e)(1) of this section.

*   *   *   *   *

7. Amend § 60.5412c by revising paragraphs (a)(1)(iv), (a)(3), and (d)(1) to read as follows:

§ 60.5412c   What additional requirements must I meet for determining initial compliance of my control devices?

*   *   *   *   *

(a)   *   *   *

(1)   *   *   *

(iv) For an enclosed combustion device other than those meeting the operating limits in paragraphs (a)(1)(ii), (iii), and (v) of this section, you must maintain the net heating value (NHV) of the gas sent to the enclosed combustion device at or above the applicable limits specified in paragraphs (a)(1)(iv)(A) through (C) of this section.

(A) For enclosed combustion devices that do not use assist gas or pressure-assisted burner tips to promote mixing at the burner tip, 200 British thermal units (Btu) per standard cubic feet (Btu/scf).

(B) For enclosed combustion devices that use pressure-assisted burner tips to promote mixing at the burner tip, 800 Btu/scf.

(C) For steam-assisted and air-assisted enclosed combustion devices, 300 Btu/scf.

* * * * *

(3) Each flare must be designed and operated according to the requirements specified in paragraphs (a)(3)(i) through (vii) of this section, as applicable. Alternatively, flares must meet the requirements specified in paragraph (d) of this section.

(i) For unassisted flares, you must maintain the NHV of the vent gas sent to the flare at or above 200 Btu/scf.

(ii) For flares that use pressure-assisted burner tips to promote mixing at the burner tip, you must maintain the NHV of the vent gas sent to the flare at or above 800 Btu/scf.

(iii) For steam-assisted and air-assisted flares, you must maintain the NHV of the vent gas sent to the flare at or above 300 Btu/scf.

(iv) For flares other than pressure-assisted flares, you must determine the maximum flow rate of vent gas to the control system based on the design considerations of the designated facilities to demonstrate compliance with the flare tip velocity limits in § 60.18(b) according to § 60.5417c(d)(8)(iv). The maximum flare tip velocity limits do not apply for pressure-assisted flares.

(v) You must operate the flare at or above the minimum inlet gas flow rate. The minimum inlet gas flow rate is established based on manufacturer recommendations.

(vi) You must operate the flare with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. You must conduct the compliance determination with the visible emission limits using Method 22 of appendix A-7 to this part, or you must monitor the flare according to § 60.5417c(h).

(vii) You must install and operate a continuous burning pilot or combustion flame. An alert must be sent to the nearest control room whenever the pilot flame is unlit.

* * * * *

(d) * * *

(1) The alternative method must be capable of demonstrating continuous compliance with a combustion efficiency of 95.0 percent or greater.

* * * * *

8. Amend § 60.5415c by revising paragraphs (c), (e)(1)(vii), (e)(1)(xi)(A), (f), (h), and (i)(15) to read as follows:

§ 60.5415c How do I demonstrate continuous compliance with the standards for each of my designated facilities?

* * * * *

(c) *Centrifugal compressor designated facility*. For each centrifugal compressor designated facility complying with the volumetric flow rate measurements requirements in § 60.5392c(a)(1) and (2), you must demonstrate continuous compliance according to paragraphs (c)(1), (3), and (4) of this section. Alternatively, for each centrifugal compressor designated facility complying with § 60.5392c(a)(3) and either § 60.5392c(a)(4) or (5) by routing emissions to a control device or to a process, you must demonstrate continuous compliance according to paragraphs (c)(2) through (4) of this section.

(1) You must maintain volumetric flow rate at or below the volumetric flow rates specified in paragraphs (c)(1)(i) through (iii) of this section for your centrifugal compressor, as applicable, and you must conduct the required volumetric flow rate measurement of your dry or wet seal in accordance with § 60.5392c(a)(1) and (2) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrates compliance with the applicable volumetric flow rate.

(i) For your wet seal centrifugal compressors (including self-contained wet seal centrifugal compressors), you must maintain the volumetric flow rate at or below 3 scfm per seal (or in the case of manifolded groups of seals, 3 scfm multiplied by the number of seals).

(ii) For your Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, you must maintain the volumetric flow rate at or below 9 scfm per seal (or in the case of manifolded groups of wet seals, 9 scfm multiplied by the number of seals).

(iii) For your dry seal compressor, you must maintain the volumetric flow rate at or below 10 scfm per seal (or in the case of manifolded groups of wet seals, 10 scfm multiplied by the number of seals).

(2) For each wet seal and dry seal centrifugal compressor designated facility complying by routing emissions to a control device or to a process, you must operate the wet seal emissions collection system and dry seal system to route emissions to a control device or a process through a closed vent system and continuously comply with the closed vent requirements of § 60.5416c. If you comply with § 60.5392c(a)(4) by using a control device, you also must comply with the requirements in paragraph (e) of this section.

(3) You must submit the annual reports as required in § 60.5420c(b)(1), (4) and (10)(i) through (iv), as applicable.

(4) You must maintain records as required in § 60.5420c(c)(3) and (7) through (9) and (11), as applicable.

*   *   *   *   *

(e)   *   *   *

(1)   *   *   *

(vii) If you use an enclosed combustion device to meet the requirements of § 60.5412c(a)(1) and you demonstrate compliance using the test procedures specified in § 60.5413c(b), or you use a flare designed and operated in accordance with § 60.5412c(a)(3), you must comply with the applicable requirements in paragraphs (e)(1)(vii)(A) through (E) of this section.

(A) For each enclosed combustion device which is not a catalytic vapor incinerator and for each flare, you must comply with the requirements in paragraphs (e)(1)(vii)(A)(*1*) through (*4*) of this section.

(1) A pilot or combustion flame must be present at all times of operation. An alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit.

(*2*) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22 of appendix A-7 to this part, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute, whichever time period is less. Alternatively, you may conduct visible emissions monitoring according to § 60.5417c(h).

(*3*) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(*4*) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 to this part visual observation as described in paragraph (e)(1)(vii)(D) of this section or be monitored according to § 60.5417c(h).

(B) For flares, you must comply with the requirements in paragraphs (e)(1)(vii)(B)(*1*) through (*5*) of this section.

(*1*) For unassisted flares, maintain the NHV of the gas sent to the flare at or above 200 Btu/scf.

(*2*) If you use a pressure assisted flare, maintain the NHV of gas sent to the flare at or above 800 Btu/scf.

(*3*) For steam-assisted and air-assisted flares, maintain the NHV of gas sent to the flare at or above 300 Btu/scf.

(*4*) Unless you use a pressure-assisted flare, maintain the flare tip velocity below the applicable limits in § 60.18(b).

(*5*) Maintain the total gas flow to the flare above the minimum inlet gas flow rate. The minimum inlet gas flow rate is established based on manufacturer recommendations.

(C) For enclosed combustion devices for which, during the performance test conducted under § 60.5413c(b), the combustion zone temperature is not an indicator of destruction efficiency, you must comply with the requirements in paragraphs (e)(1)(vii)(C)(*1*) through (*4*) of this section, as applicable.

(*1*) Maintain the total gas flow to the enclosed combustion device at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustion device established in accordance with § 60.5417c(f).

(*2*) For unassisted enclosed combustion devices, maintain the NHV of the gas sent to the enclosed combustion device at or above 200 Btu/scf.

(*3*) For enclosed combustion devices that use pressure-assisted burner tips to promote mixing at the burner tip, maintain the NHV of the gas sent to the enclosed combustion device at or above 800 Btu/scf.

(*4*) For steam-assisted and air-assisted enclosed combustion devices, maintain the NHV-of gas sent to the flare at or above 300 Btu/scf.

(D) For enclosed combustion devices for which, during the performance test conducted under § 60.5413c(b), the combustion zone temperature is demonstrated to be an indicator of destruction efficiency, you must comply with the requirements in paragraphs (e)(1)(vii)(D)(*1*) and (*2*) of this section.

(*1*) Maintain the temperature at or above the minimum temperature established during the most recent performance test. The minimum temperature limit established during the most recent performance test is the average temperature recorded during each test run, averaged across the 3 test runs (average of the test run averages).

(*2*) Maintain the total gas flow to the enclosed combustion device at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustion device established in accordance with § 60.5417c(f).

(E) For catalytic vapor incinerators you must operate the catalytic vapor incinerator at or above the minimum temperature of the catalyst bed inlet and at or above the minimum temperature differential between the catalyst bed inlet and the catalyst bed outlet established in accordance with § 60.5417c(f).

* * * * *

(xi) * * *

(A) You must maintain the combustion efficiency at or above 95.0 percent.

* * * * *

(f) *Reciprocating compressor designated facility.* For each reciprocating compressor designated facility complying with § 60.5393c(a) through (c), you must demonstrate continuous compliance according to paragraphs (f)(1), (3), (5), and (6) of this section. For each reciprocating compressor designated facility complying with § 60.5393c(d)(1) or (2), you must demonstrate continuous compliance according to paragraphs (f)(2), (5), and (6) of this section. For each reciprocating compressor affected facility complying with § 60.5393c(d)(3), you must demonstrate continuous compliance according to paragraphs (f)(3) through (6) of this section.

(1) You must maintain the volumetric flow rate at or below 2 scfm per cylinder (or at or below the combined volumetric flow rate determined by multiplying the number of cylinders by 2 scfm), and you must conduct the required volumetric flow rate measurement of your reciprocating compressor rod packing vents in accordance with § 60.5393c(b) or (c) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrated compliance with the applicable volumetric flow rate.

(2) You must operate the rod packing emissions collection system to route emissions to a control device or to a process through a closed vent system and continuously comply with the cover and closed vent requirements of § 60.5416c. If you comply with § 60.5393c(d) by using a control device, you also must comply with the requirements in paragraph (e) of this section.

(3) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility since initial startup, since 60 days after the state plan submittal deadline (as specified in § 60.5362c(c)), since the previous flow rate measurement, or since the date of the most recent reciprocating compressor rod packing replacement, whichever date is latest.

(4) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 8,760 hours.

(5) You must submit the annual reports as required in § 60.5420c(b)(1) and (5) and (b)(10)(i) through (iv), as applicable.

*   *   *   *   *

(h) *Storage vessel designated facility*. For each storage vessel designated facility, you must demonstrate continuous compliance with the requirements of § 60.5396c according to paragraphs (h)(1) through (10) of this section, as applicable.

(1) For each storage vessel designated facility complying with the requirements of § 60.5396c(a)(2), you must demonstrate continuous compliance according to paragraphs (h)(5) and (9) and (10) of this section.

(2) For each storage vessel designated facility complying with the requirements of § 60.5396c(a)(3), you must demonstrate continuous compliance according to paragraphs (h)(2)(i), (ii), or (iii) of this section, as applicable, and (h)(9) and (10) of this section.

(i) You must maintain the uncontrolled actual methane emissions from the storage vessel designated facility at less than 14 tpy.

(ii) You must comply with paragraph (h)(5) of this section as soon as liquids from the well are routed to the storage vessel designated facility following fracturing or refracturing according to the requirements of § 60.5396c(a)(3)(i).

(iii) You must comply with paragraph (h)(5) of this section within 30 days of the monthly determination according to the requirements of § 60.5396c(a)(3)(ii), where the monthly emissions determination indicates that methane emissions from your storage vessel designated facility increase to 14 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel designated facility.

(3) For each storage vessel designated facility or portion of a storage vessel designated facility removed from service, you must demonstrate compliance with the

requirements of § 60.5396c(c)(1) or (2) by complying with paragraphs (h)(6), (7), (9), and (10) of this section.

(4) For each storage vessel designated facility or portion of a storage vessel designated facility returned to service, you must demonstrate compliance with the requirements of § 60.5396c(c)(3) and (4) by complying with paragraphs (h)(8) through (10) of this section.

(5) For each storage vessel designated facility, you must comply with paragraphs (h)(5)(i) and (ii) of this section.

(i) You must reduce methane emissions as specified in § 60.5396c(a)(2).

(ii) For each control device installed to meet the requirements of § 60.5396c(a)(2), you must demonstrate continuous compliance with the performance requirements of § 60.5412c for each storage vessel designated facility using the procedure specified in paragraphs (h)(5)(ii)(A) and (B) of this section. When routing emissions to a process, you must demonstrate continuous compliance as specified in paragraph (h)(5)(ii)(A) of this section.

(A) You must comply with § 60.5416c for each cover and closed vent system.

(B) You must comply with the requirements specified in paragraph (e) of this section.

(6) You must completely empty and degas each storage vessel, such that each storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. For a portion of a storage vessel designated facility to be removed from service, you must completely empty and degas the storage vessel(s), such that the storage vessel(s) no longer contains crude oil, condensate, produced water or

intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(7) You must disconnect the storage vessel(s) from the tank battery by isolating the storage vessel(s) from the tank battery such that the storage vessel(s) is no longer manifolded to the tank battery by liquid or vapor transfer.

(8) You must determine the designated facility status of a storage vessel returned to service as provided in § 60.5386c(e)(5).

(9) You must submit the annual reports as required by § 60.5420c(b)(1) and (7) and (b)(10)(i) through (iv).

(10) You must maintain the records as required by § 60.5420c(c)(6) through (9) and (11), as applicable.

* * * * *

(i) * * *

(15) You must maintain the records specified by § 60.5420c(c)(7), (9), and (11) as applicable and § 60.5421c.

* * * * *

9. Amend § 60.5417c by revising paragraphs (d)(8), (e), (f)(1)(iv), (g)(1), (6) and (7), and (i)(6)(i) to read as follows:

§ 60.5417c What are the continuous monitoring requirements for my control devices?

* * * * *

(d) * * *

(8) For an enclosed combustion device, other than those listed in paragraphs (d)(1) through (3) and (7) of this section, or for a flare, continuous monitoring systems as specified in paragraphs (d)(8)(i) through (iv) of this section and visible emission observations conducted as specified in paragraph (d)(8)(v) of this section.

(i) Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times. An alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

(ii) Except as provided in this paragraph (d)(8)(ii) and paragraph (d)(8)(iii) of this section, use one of the following methods to continuously determine the NHV of the inlet gas to the enclosed combustion device or flare at standard conditions. Except for pressure assisted flares and pressure assisted enclosed combustion devices, if the inlet gas stream to the flare or enclosed combustion device does not include streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.*, vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), the NHV of the inlet stream is considered to be sufficiently above the minimum required NHV for the inlet gas, and you are not required to conduct the continuous monitoring in this paragraph (d)(8)(ii) or the demonstration in paragraph (d)(8)(iii) of this section, but you must submit the report in § 60.5420c(b)(10)(v)(I) and maintain the record in § 60.5420c(c)(10)(vi) indicating that the flare or enclosed combustion device does not receive inert gas or other vent gas streams which may lower the NHV of the combined stream.

(A) A calorimeter with a minimum accuracy of ±2 percent of span.

(B) A gas chromatograph that meets the requirements in paragraphs (d)(8)(ii)(B)(*1*) through (*5*) of this section.

(*1*) You must follow the procedure in Performance Specification 9 of appendix B to this part, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(*2*) You must meet the accuracy requirements in Performance Specification 9 of appendix B to this part.

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the gas chromatograph in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(B)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. Use the response factor for the nearest normal hydrocarbon (i.e., n-alkane) in the calibration mixture to quantify unknown components detected in the analysis. Use the response factor for n-pentane to quantify unknown components detected in the analysis that elute after n-pentane.

(*5*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published values for the net heating value per mole at 25 °C and 1 atmosphere and use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(C) A mass spectrometer that meets the requirements in paragraphs (d)(8)(ii)(C)(*1*) through (*6*) of this section.

(*1*) You must meet applicable requirements in Performance Specification 9 of appendix B of this part for continuous monitoring system acceptance including, but not limited to, performing an initial multi-point calibration check at three concentrations following the procedure in Section 10.1. A single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C). Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to NIST standards.

(*2*) The average instrument calibration error (CE) for each calibration compound at any calibration concentration must not differ by more than 10 percent from the certified cylinder gas value. The CE for each component in the calibration blend must be calculated using the following equation:

Equation 1 to paragraph (d)(8)(ii)(C)(*2*)

$$CE = \frac{C_m - C_a}{C_a} \times 100$$

Where:
C_m = Average instrument response (ppm).
Ca = Certified cylinder gas value (ppm).

(*3*) You must use a calibration gas or multiple gases that includes the compounds that are reasonably expected to be present in the flare gas stream. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. You may only use the compounds used to calibrate the mass spectrometer in the calculation of the vent gas NHV.

(*4*) In lieu of the calibration gas described in paragraph (d)(8)(ii)(C)(*3*) of this section, you may use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, you must calibrate the instrument on all of the gases. For unknown gas components that have similar analytical mass fragments to calibration compounds, you may report the unknowns as an increase in the overlapped calibration gas compound. For unknown compounds that produce mass fragments that do not overlap calibration compounds, you may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component. You may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.

(*5*) You must perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

(*6*) To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use any published value for the net heating value per mole at 25 °C and 1 atmosphere use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(D) A grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours. Subsequent compositional analysis of the samples must be performed according to ASTM D1945–14 (R2019) or alternatively GPA 2261-19 (incorporated by reference, see § 60.17). To determine the NHV of the vent gas, determine the product of the volume fraction of the individual component in the vent gas and the net heating value of that individual component. Sum the products for all components in the vent gas to determine the NHV for the vent gas. For the net heating value of each individual component, use the net heating value per mole at 25 °C and 1 atmosphere use 20 °C as the standard temperature for determining the volume corresponding to one mole of vent gas.

(iii) As an alternative to the continuous composition monitoring requirements in paragraph (d)(8)(ii) of this section, a sampling demonstration may be used as specified in this paragraph. Flares or enclosed combustion devices that are not required to monitor flare gas composition because the inlet gas streams to the flare or enclosed combustion device does not include streams from processes or equipment where inert gas or other vent gas streams which may lower the NHV of the combined stream are added (*e.g.*, vent streams from acid gas removal (AGR) system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers without water removal, vent streams from compressors in acid gas service, vent streams containing water or CO_2 used for enhanced oil recovery, vent streams from storage vessels with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV, vent streams from gas plants that receive acid gas from sweetening units, and vent streams from nitrogen removal units (NRU)), are not required to conduct sampling demonstrations specified in this paragraph. For flare or enclosed combustion device, if you demonstrate according to the methods described in paragraphs (d)(8)(iii)(A) through (F) of this section that the NHV of the inlet gas to the enclosed combustion device or flare consistently exceeds the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C), continuous monitoring of the NHV is not required, but you must conduct the ongoing sampling in paragraph (d)(8)(iii)(G) of this section. For an unassisted or pressure-assisted flare or enclosed combustion device, in lieu of conducting the demonstration outlined in paragraphs (d)(8)(iii)(A) through (D) of this section, you may conduct the demonstration outlined in paragraph (d)(8)(iii)(H) of this section, but you must still comply with paragraphs (d)(8)(iii)(E) through (G) of this section.

(A) Continuously monitor the inlet stream which is routed to the flare or enclosed combustor for 14 operating days or collect a sample of the inlet gas which is routed to the enclosed combustion device or flare twice daily to determine the average NHV of the gas stream for 14 operating days with no sampling day to be spaced more than 3 operating days apart from the previous sampling day. If you do not continuously monitor the NHV, the minimum time of collection for each individual sample be at least one hour when technically feasible. When it is not technically feasible to collect individual samples for at least one hour (*e.g.*, low or intermittent flow), the collection time must be as long as possible up to one hour. For samples taken during low or intermittent flow events, the collection time and the reason for not obtaining a full one hour sample must be documented and reported with the NHV sampling results. Samples must be separated by at least 6 hours. If inlet gas flow is intermittent such that there are not at least 28 samples over the 14 operating day period, you must continue to collect samples of the inlet gas beyond the 14 operating day period until you collect a minimum of 28 samples.

(B) If you collect samples twice per day, count the number of samples where the NHV value is less than 1.2 times the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C) (i.e., values that are less than 240, 360, or 960 Btu/scf, as applicable) during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(C) If you continuously sample the inlet stream for 14 days, count the number of hourly block average (*e.g.*, noon to 1 pm, 1 pm to 2 pm, etc.) NHV values that are less than the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C), (*i.e.*, values that are less than 200, 300, or 800 Btu/scf, as applicable), during the sample collection period in paragraph (d)(8)(iii)(A) of this section.

(D) If there are no samples counted under paragraph (d)(8)(iii)(B) of this section or there are no hourly values counted under paragraph (d)(8)(iii)(C) of this section, the gas stream is considered to consistently exceed the applicable NHV operating limit and on-going continuous monitoring is not required.

(E) If process operations are revised that could reduce the NHV of the gas sent to the enclosed combustion device or flare, such as the removal or addition of process equipment, and at any time the Administrator requires, re-evaluation of the gas stream must be performed according to paragraphs (d)(8)(iii)(A) through (D) of this section within 60 days of the revisions to process operations to ensure the gas stream still consistently exceeds the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C), or this paragraph (d)(8)(iii). If any of the samples counted under paragraph (d)(8)(iii)(B) of this section or any hourly values counted under paragraph (d)(8)(iii)(C) of this section are less than the limits in the respective paragraph you must conduct the continuous monitoring required by one of the options specified in paragraphs (d)(8)(ii)(A) through (D) of this section within 60 days of the re-evaluation of the gas stream.

(F) When collecting samples under paragraph (d)(8)(iii)(A) of this section, the owner or operator must account for any sources of inert gases or other vent gas streams which may lower the NHV of the combined stream (*e.g.*, vent streams from AGR system amine regenerator still columns, vent streams from glycol dehydrator unit reboilers, vent streams from compressors in acid gas service, vent streams from enhanced oil recovery facilities, or vent streams from storage vessel with high water content where the owner or operator has determined that the vent stream could cause the inlet gas to the enclosed combustion device or flare to not meet the minimum NHV) that can be sent to the enclosed combustion device or flare. The owner or operator must document in the report in § 60.5420c(b)(10)(v)(I) and the records in § 60.5420c(c)(10)(vi) must note the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams which may lower the NHV of the combined stream, and whether the sampling included periods where the highest percentage of inert gases or other vent gas streams which may lower the NHV of the combined stream were sent to the enclosed combustion device or flare. If the introduction of inerts or other vent gas streams which may lower the NHV of the combined stream is intermittent and does not occur during the initial demonstration, the introduction of inerts or other vent gas streams which may lower the NHV of the combined stream will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E) of this section. If conditions at the site did not allow sampling during periods where the introduction of inert gases or other vent gas streams which may lower the NHV of the combined stream was at the highest percentage possible, increasing the percentage of inerts will be considered a revision to process operations that triggers a re-evaluation under paragraph (d)(8)(iii)(E).

(G) You must collect three samples of the inlet gas to the enclosed combustion device or flare at least once every 5 years. The minimum time of collection for each individual sample must be at least one hour when technically feasible. When it is not technically feasible to collect individual samples for at least one hour (*e.g.*, low or intermittent flow), the collection time must be as long as possible up to one hour. For samples taken during low or intermittent flow events, the collection time and the reason for not obtaining a full one hour sample must be documented and reported with the NHV sampling results. The samples must be taken during the period with the lowest expected NHV (*i.e.*, the period with the highest percentage of inerts or other vent gas streams which may lower the NHV of the combined stream). The first set of periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the last sample taken under paragraph (d)(8)(iii)(A) of this section. Subsequent periodic samples must be taken, or continuous monitoring commenced, no later than 60 calendar months following the previous sample. If any sample has an NHV value less than 1.2 times the applicable operating limit specified in § 60.5415c(e)(1)(vii)(B) or (C) (*i.e.*, values that are less than 240, 360, or 960 Btu/scf, as applicable), you must conduct the continuous monitoring required by one of the options in paragraphs (d)(8)(ii)(A) through (D) of this section within 60 days or receipt of the last sample.

(H) You may request an alternative test method under § 60.5412c(d) to demonstrate that the flare or enclosed combustion device reduces methane and VOC in the gases vented to the device by 95.0 percent by weight or greater. You must measure data values at the frequency specified in the alternative test method and conduct the quality assurance and quality control requirements outlined in the alternative test method at the frequency outlined in the alternative test method. You must monitor the combustion efficiency of the flare continuously for 14 days. If there are no values of the combustion efficiency measured by the alternative test method that are less than 95.0 percent, the gas stream is considered to consistently exceed the applicable NHV operating limit, and you are not required to continuously monitor the NHV of the inlet gas to the flare or enclosed combustion device.

(iv) Except as noted in paragraphs (d)(8)(iv)(A) through (C) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustion device or flare. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as inlet line pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate.

(A) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(B) Flares are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(B)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the flare cannot cause the flare tip velocity to exceed the maximum tip velocity as specified in the applicable provisions in § 60.18(c) and (f) of this chapter. You must use the minimum expected value of the NHV of the inlet gas to the flare or enclosed combustion based on previous sampling results or process knowledge of the streams sent to the enclosed flare of combustion device in your demonstration. If there are changes to the process or control device that can be reasonably expected to increase the maximum flow rate to the flare, you must conduct a new demonstration to determine whether the maximum flow rate to the flare is compliant with the applicable maximum flare tip velocity provisions in § 60.18(c) and (f) of this chapter.

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(C) Enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device if you meet the conditions in paragraphs (d)(8)(iv)(C)(*1*) and (*2*) of this section.

(*1*) You must demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustion device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustion device cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section to be exceeded. If there are changes to the process or control device that can be reasonably expected to impact the maximum flow rate to the enclosed combustion device, you must conduct a new demonstration to determine whether the maximum flow rate to the enclosed combustor is less than the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section.

(*2*) You must install, calibrate, maintain, and operate a backpressure regulator valve calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. The set point must be consistent with manufacturer specifications for minimum flow or pressure and must be supported by an engineering evaluation. At least annually, you must confirm that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications and that the valve fully closes when not in the open position.

(v) Conduct inspections monthly and at other times as requested by the Administrator to monitor for visible emissions from the combustion device using section 11 of Method 22 of appendix A to this part or conduct visible emissions monitoring according to paragraph (h) of this section. The observation period shall be 15 minutes or once the amount of time visible emissions is present has exceeded 1 minute. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period.

(e) Calculate the value of the applicable monitored parameter in accordance with paragraphs (e)(1) through (4) of this section.

(1) You must calculate the daily average value for condenser outlet temperature for each operating day, using the data recorded by the monitoring system. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(2) You must use the 5-minute readings from the heat sensing devices to assess the presence of a pilot or combustion flame.

(3) You must use the regeneration cycle time (*i.e.*, duration of the carbon bed steaming cycle) for each regenerative-type carbon adsorption system to calculate the average parameter to compare with the maximum steam mass flow or volumetric flow during each carbon bed regeneration cycle and the maximum carbon bed temperature during the steaming cycle. The carbon bed temperature after the regeneration cycle should not be averaged; you must use the carbon bed temperature measured within 15 minutes of completing the cooling cycle to compare with the minimum carbon bed temperature after the regeneration cycle.

(4) For all operating parameters others than those described in paragraphs (e)(1) through (3) of this section, you must calculate the 3-hour rolling average of each monitored parameter. For each operating hour, calculate the hourly value of the operating parameter from your continuous monitoring system. Average the three most recent hours

of data to determine the 3-hour average. Determine the 3-hour rolling average by recalculating the 3-hour average each hour.

(f) * * *

(1) * * *

(iv) If you operate an enclosed combustion device where the combustion zone temperature is not an indicator of destruction efficiency or a control device where the performance test requirement was met under § 60.5413c(d), you must maintain the NHV of the gas sent to the enclosed combustion device above the applicable limits specified in § 60.5412c(a)(1)(iv)(A) through (C).

* * * * *

(g) * * *

(1) A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is below the applicable limits specified in § 60.5415c(e)(1)(vii)(B)(*1*) through (*3*) and (*5*) or above the limit specified in § 60.5415c(e)(1)(vii)(B)(*4*); or for each flare or enclosed combustion device except for boilers and process heaters meeting the requirements in § 60.5412c(a)(1)(iii) and catalytic vapor incinerators meeting the requirements in § 60.5412c(a)(1)(v), when the heat sensing device indicates that there is no pilot or combustion flame present for any time period. If you use a backpressure regulator valve to maintain the inlet gas flow to an

enclosed combustion device or flare above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not fully close when not in the open position.

*   *   *   *   *

(6) For a combustion control device whose model is tested under § 60.5413c(d), a deviation occurs when the conditions of paragraph (g)(4), (5), or (6)(i) through (v) of this section are met.

(i) The hourly inlet gas flow rate is less than the minimum inlet gas flow rate or greater than the maximum inlet gas flow rate determined by the manufacturer. If you use a backpressure regulator valve to maintain the inlet gas flow above the minimum value, a deviation occurs if the annual inspection finds that the backpressure regulator valve set point is not set correctly or indicates that the backpressure regulator valve does not fully close when not in the open position.

(ii) Results of the monthly visible emissions test conducted under § 60.5413c(e)(3) or monitoring under paragraph (h) of this section indicate visible emissions exceed 1 minute in any 15-minute period.

(iii) There is no indication of the presence of a pilot or combustion flame for any 5-minute time period.

(iv) The control device is not maintained in a leak free condition.

(v) The control device is not operated in accordance with the manufacturer's written operating instructions, procedures and maintenance schedule.

(7) For an enclosed combustion device or flare subject to paragraph (d)(8) of this section, a deviation occurs when any of the conditions described by paragraph (g)(1), (4), or (5) of this section are met or when the results of the visible emissions monitoring conducted under paragraph (d)(8)(v) or (h) of this section exceed 1 minute in any 15-minute period.

*   *   *   *   *

(i)   *   *   *

(6)   *   *   *

(i) A deviation occurs if the combustion efficiency is less than 95.0 percent.

*   *   *   *   *

10. Amend § 60.5420c by revising paragraphs (a)(3),(b), (c), and (d) introductory text to read as follows:

§ 60.5420c What are my notification, reporting, and recordkeeping requirements?

(a)   *   *   *

(3) *Notification to Administrator*. An owner or operator who commences well closure activities must submit the following notices to the Administrator according to the schedule in paragraphs (a)(3)(i) and (ii) of this section. The notification shall include contact information for the owner or operator; the United States Well Number; 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. You must submit notifications in portable document format (PDF) following the procedures specified in paragraph (d) of this section.

(i) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site.

(ii) You must submit a notification of the intent to close a well site 60 days before you begin well closure activities.

(b) *Reporting requirements*. You must submit annual reports containing the information specified in paragraphs (b)(1) through (13) of this section following the procedure specified in paragraph (b)(14) of this section. You must submit performance test reports as specified in paragraph (b)(11) or (12) of this section, if applicable. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410c. Subsequent annual reports are due no later than the same date each year as the initial annual report. If you own or operate more than one designated facility, you may submit one report for multiple designated facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (13) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period. You must submit the information in paragraph (b)(1)(v) of this section, as applicable, for your well designated facility which undergoes a change of ownership during the reporting period, regardless of whether reporting under paragraphs (b)(2) and (3) of this section is required for the well designated facility.

(1) The general information specified in paragraphs (b)(1)(i) through (v) of this section is required for all reports.

(i) The company name, facility site name associated with the designated facility, U.S. Well ID or U.S. Well ID associated with the designated facility, if applicable, and address of the designated facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each designated facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (b)(1)(iv).

(v) Identification of each well designated facility for which ownership changed due to sale or transfer of ownership including the United States Well Number; the latitude and longitude coordinates of the well designated facility in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the information in paragraph (b)(1)(v)(A) or (B) of this section, as applicable.

(A) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator to which you sold or transferred ownership of the well designated facility identified in paragraph (b)(1)(v) of this section.

(B) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator from whom you acquired the well designated facility identified in paragraph (b)(1)(v) of this section.

(2) For each well designated facility that is subject to § 60.5390c(a)(1) or (2), your annual report is required to include the information specified in paragraphs (b)(2)(i) and (ii) of this section, as applicable.

(i) For each well designated facility where all gas well liquids unloading operations comply with § 60.5390c(a)(1), your annual report must include the information specified in paragraphs (b)(2)(i)(A) through (C) of this section, as applicable.

(A) Identification of each well designated facility (U.S. Well ID or U.S. Well ID associated with the well designated facility) that conducts a gas well liquid unloading operation during the reporting period using a method that does not vent to the atmosphere and the technology or technique used. If more than one non-venting technology or technique is used, you must identify all of the differing non-venting liquids unloading methods used during the reporting period.

(B) Number of gas well liquids unloading operations conducted during the year where the well designated facility identified in (b)(2)(i)(A) had unplanned venting to the atmosphere and best management practices were conducted according to your best management practice plan, as required by § 60.5390c(c). If no venting events occurred, the number would be zero. Other reported information required to be submitted where unplanned venting occurs is specified in paragraphs (b)(2)(i)(B)(*1*) and (*2*) of this section.

(*1*) Log of best management practice plan steps used during the unplanned venting to minimize emissions to the maximum extent possible.

(*2*) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(C) The number of liquids unloading events where unplanned emissions are vented to the atmosphere during a gas well liquids unloading operation where you complied with best management practices to minimize emissions to the maximum extent possible.

(ii) For each well designated facility where all gas well liquids unloading operations comply with § 60.5390c(b) and (c) best management practices, your annual report must include the information specified in paragraphs (b)(2)(ii)(A) through (E) of this section.

(A) Identification of each well designated facility that conducts a gas well liquids unloading during the reporting period.

(B) Number of liquids unloading events conducted during the reporting period.

(C) Log of best management practice plan steps used during the reporting period to minimize emissions to the maximum extent possible.

(D) The number of liquids unloading events during the year that best management practices were conducted according to your best management practice plan.

(E) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(3) For each associated gas well at your well designated facility that is subject to § 60.5391c, your annual report is required to include the applicable information specified in paragraphs (b)(3)(i) through (v) of this section, as applicable.

(i) For each associated gas well at your well designated facility that complies with § 60.5391c(a)(1), (2), (3), or (4) your annual report is required to include the information specified in paragraphs (b)(3)(i)(A) and (B) of this section.

(A) An identification of each existing associated gas well that complies with § 60.5391c(a)(1), (2), (3), or (4).

(B) The information specified in paragraphs (b)(3)(i)(B)(*1*) through (*4*) of this section for each incident when the associated gas was temporarily routed to a flare or control device in accordance with § 60.5391c(c).

(*1*) The reason in § 60.5391c(c)(1), (2), (3), or (4) for each incident.

(2) The start date and time of each incident of routing associated gas to the flare or control device, along with the total duration in hours of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411c(a) and (c) and all applicable flare or control device requirements specified in § 60.5412c were met during each period when the associated gas is routed to the flare or control device.

(*4*) For each instance where you route associated gas to a flare or control device beyond 72 hours due to "exigent circumstances" according to § 60.5391c(c)(1) or (2), you must include the record information specified in paragraph (c)(2)(vi) of this section in your annual report.

(ii) For all instances where you temporarily vent the associated gas in accordance with § 60.5391c(d), you must report the information specified in paragraphs (b)(3)(ii)(A) through (D) of this section. This information is required to be reported if you are routinely complying with § 60.5391c(a) or (b) or temporarily complying with § 60.5391c(c). In addition to this information for each incident, you must report the cumulative duration in hours of venting incidents and the cumulative VOC and methane emissions in pounds for all incidents in the calendar year.

(A) The reason in § 60.5391c(d)(1), (2), or (3) for each incident.

(B) The start date and time of each incident of venting the associated gas, along with the total duration in hours of each incident.

(C) The methane emissions in pounds that were emitted during each incident.

(D) The total duration of venting for all incidents in the year, along with the cumulative methane emissions in pounds that were emitted.

(iii) For each associated gas well at your well designated facility that complies with the requirements of § 60.5391c(b) by routing your associated gas to a control device that reduces methane emissions by at least 95.0 percent, your annual report must include the information specified in paragraphs (b)(3)(iii)(A) through (C), and paragraph (D) or (E) of this section. The information in paragraphs (b)(3)(iii)(A) and (B) of this section is only required in the initial annual report.

(A) Identification of the associated gas well using the control device and the information in paragraph (b)(10)(v) of this section.

(B) The information specified in paragraphs (b)(10)(i) through (iv) of this section.

(C) Identification of each instance when associated gas was vented and not routed to a control device that reduces methane emissions by at least 95.0 percent in accordance with paragraph (b)(3)(ii) of this section.

(D) For each associated gas well that complies with the requirements of § 60.5391c(b) because it has demonstrated that annual methane emissions are 40 tons per year or less, provide records of the calculation of annual methane emissions determined in accordance with § 60.5391c(e)(1).

(E) For each associated gas well facility that complies with the requirements of § 60.5391c(b) because it has demonstrated that it is not feasible to comply with § 60.5391c(a)(1), (2), (3), or (4) due to technical reasons, provide each annual demonstration and certification of the technical reason that it is not feasible to comply with § 60.5391c(a)(1) through (4) in accordance with § 60.5391c(b)(2)(i) through (iii).

(iv) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(v) For each deviation recorded as specified in paragraph (c)(2)(vi) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(4) For each centrifugal compressor that is a designated facility, the information specified in paragraphs (b)(4)(i) through (ix) of this section, as applicable.

(i) An identification of each centrifugal compressor.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(3) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) If complying with § 60.5392c(a)(1) and (2) wet and dry seal centrifugal compressor requirements, the cumulative number of hours of operation since initial startup, since 36 months after the state plan submittal deadline (as specified in § 60.5362c(c)), or since the previous volumetric flow rate measurement, as applicable, which have elapsed prior to conducting your volumetric flow rate measurement or emissions screening.

(iv) A description of the method used and the results of the volumetric emissions measurement or emissions screening, as applicable.

(v) If required to comply with § 60.5392c(a)(5), the information specified in paragraphs (b)(10)(i) through (iv) of this section.

(vi) If complying with § 60.5392c(a)(4) with a control device, identification of the centrifugal compressor with the control device and the information in paragraph (b)(10)(v) of this section.

(vii) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(viii) Number and type of seals on delay of repair and explanation for each delay of repair.

(ix) Date of planned shutdown(s) that occurred during the reporting period if there are any seals that have been placed on delay of repair.

(5) For each reciprocating compressor designated facility, the information specified in paragraphs (b)(5)(i) through (vii) of this section, as applicable.

(i) The cumulative number of hours of operation since initial startup, since 36 months after the state plan submittal deadline (as specified in § 60.5362c(c)), since the previous volumetric flow rate measurement, or since the previous reciprocating compressor rod packing replacement, as applicable, which have elapsed prior to conducting your volumetric flow rate measurement or emissions screening. Alternatively, a statement that emissions from the rod packing are being routed to a process or control device through a closed vent system.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(4)(i) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(iv) If complying with § 60.5393c(d)(1) or (2), the information in paragraphs (b)(10)(i) through (v) of this section.

(v) Number and type of rod packing replacements/repairs on delay of repair and explanation for each delay of repair.

(vi) Date of planned shutdown(s) that occurred during the reporting period if there are any rod packing replacements/repairs that have been placed on delay of repair.

(vii) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(6) For each process controller designated facility, the information specified in paragraphs (b)(6)(i) through (iii) of this section in your initial annual report and in subsequent annual reports for each process controller designated facility that is constructed, modified, or reconstructed during the reporting period. Each annual report must contain the information specified in paragraphs (b)(6)(iv) through (x) of this section for each process controller designated facility.

(i) An identification of each existing process controller that is driven by natural gas, as required by § 60.5394c(d), that allows traceability to the records required in paragraph (c)(5)(i) of this section.

(ii) For each process controller in the designated facility complying with § 60.5394c(a), you must report the information specified in paragraphs (b)(6)(ii)(A) and (B) of this section, as applicable.

(A) An identification of each process controller complying with § 60.5394c(a)(1) by routing the emissions to a process.

(B) An identification of each process controller complying with § 60.5394c(a)(2) by using a self-contained natural gas-driven process controller.

(iii) For each process controller designated facility located at a site in Alaska that does not have access to electrical power and that complies with § 60.5394c(b), you must report the information specified in paragraph (b)(6)(iii)(A), (B), or (C) of this section, as applicable.

(A) For each process controller complying with § 60.5394c(b)(1) process controller bleed rate requirements, you must report the information specified in paragraphs (b)(6)(iii)(A)(*1*) and (*2*) of this section.

(*1*) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(*2*) Where necessary to meet a functional need, the identification and demonstration of why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(B) An identification of each intermittent vent process controller complying with the requirements in paragraph § 60.5394c(b)(2).

(C) An identification of each process controller complying with the requirements in § 60.5394c(b) by routing emissions to a control device in accordance with § 60.5394c(b)(3).

(iv) Identification of each process controller which changes its method of compliance during the reporting period and the applicable information specified in paragraphs (b)(6)(v) through (ix) of this section for the new method of compliance.

(v) For each process controller in the designated facility complying with the requirements of § 60.5394c(a) by routing the emissions to a process, you must report the information specified in paragraphs (b)(10)(i) through (iv) of this section.

(vi) For each process controller in the designated facility complying with the requirements of § 60.5394c(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (b)(6)(vi)(A) and (B) of this section.

(A) Dates of each inspection required under § 60.5416c(b); and

(B) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and the date of repair or date of anticipated repair if repair is delayed.

(vii) For each process controller in the designated facility complying with the requirements of § 60.5394c(b)(2), you must report the information specified in paragraphs (b)(6)(vii)(A) and (B) of this section.

(A) Dates and results of the intermittent vent process controller monitoring required by § 60.5394c(b)(2)(ii).

(B) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement or the date of anticipated repair or replacement if the repair or replacement is delayed, and the date and results of the re-survey after repair or replacement.

(viii) For each process controller designated facility complying with § 60.5394c(b)(3) by routing emissions to a control device, you must report the information specified in paragraph (b)(10) of this section.

(ix) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(x) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(6)(ii)(B) and (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(7) For each storage vessel designated facility, the information in paragraphs (b)(7)(i) through (x) of this section.

(i) An identification, including the location, of each existing storage vessel designated facility. The location of the storage vessel designated facility shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the methane emission rate determination according to § 60.5386c(e)(1) for each tank battery that became a designated facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(6)(iii) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iv) For each storage vessel designated facility complying with § 60.5396c(a)(2) with a control device, report the identification of the storage vessel designated facility with the control device and the information in paragraph (b)(10)(v) of this section.

(v) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(vi) If required to comply with § 60.5396c(b)(1), the information in paragraphs (b)(10)(i) through (iv) of this section.

(vii) You must identify each storage vessel designated facility that is removed from service during the reporting period as specified in § 60.5396c(c)(1)(ii), including the date the storage vessel designated facility was removed from service. You must identify each storage vessel that that is removed from service from a storage vessel designated facility during the reporting period as specified in § 60.5396c(c)(2)(iii), including identifying the impacted storage vessel designated facility and the date each storage vessel was removed from service.

(viii) You must identify each storage vessel designated facility or portion of a storage vessel designated facility returned to service during the reporting period as specified in § 60.5396c(c)(4), including the date the storage vessel designated facility or portion of a storage vessel designated facility was returned to service.

(ix) You must identify each storage vessel designated facility that no longer complies with § 60.5396c(a)(3) and instead complies with § 60.5396c(a)(2). You must identify whether the change in the method of compliance was due to fracturing or refracturing or whether the change was due to an increase in the monthly emissions determination. If the change was due to an increase in the monthly emissions determination, you must provide documentation of the emissions rate. You must identify the date that you complied with § 60.5396c(a)(2) and must submit the information in (b)(7)(iii) through (vii) of this section.

(x) You must submit a statement that you are complying with § 60.112b(a)(1) or (2), if applicable, in your initial annual report.

(8) For the fugitive emissions components designated facility, report the information specified in paragraphs (b)(8)(i) through (iv) of this section, as applicable.

(i)

(A) Designation of the type of site (*i.e.*, well site, centralized production facility, or compressor station) at which the fugitive emissions components designated facility is located.

(B) For the fugitive emissions components designated facility at a well site or centralized production facility that became a designated facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For the fugitive emissions components designated facility at a compressor station that became a designated facility during the reporting period, you must include the date of startup or the date of modification.

(C) For the fugitive emissions components designated facility at a well site, you must specify what type of well site it is (*i.e.*, single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment).

(D) For the fugitive emissions components designated facility at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For the fugitive emissions components designated facility at a well site where you previously reported under paragraph (b)(8)(i)(D) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(F) For the fugitive emissions components designated facility at a well site where during the reporting period you undertake well closure requirements, the date of the cessation of production from all wells at the well site, the date you began well closure activities at the well site, and the dates of the notifications submitted in accordance with paragraph (a)(3) of this section.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(8)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument or, if the survey was conducted by visual, audible, or olfactory methods, notation that AVO was used.

(C) Any deviations from the monitoring plan elements under § 60.5397c(c)(1), (2), (7), and (8) or (d) or a statement that there were no deviations from these elements of the monitoring plan.

(D) Number and type of components for which fugitive emissions were detected.

(E) Number and type of fugitive emissions components that were not repaired as required in § 60.5397c(h).

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

(G) Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

(iii) For well closure activities which occurred during the reporting period, the information in paragraphs (b)(8)(iii)(A) and (B) of this section.

(A) A status report with dates for the well closure activities schedule developed in the well closure plan. If all steps in the well closure plan are completed in the reporting period, the date that all activities are completed.

(B) If an OGI survey is conducted during the reporting period, the information in paragraphs (b)(8)(iii)(B)(*1*) through (*3*) of this section.

(*1*) Date of the OGI survey.

(*2*) Monitoring instrument used.

(*3*) A statement that no fugitive emissions were found, or if fugitive emissions were found, a description of the steps taken to eliminate those emissions, the date of the resurvey, the results of the resurvey, and the date of the final resurvey which detected no emissions.

(iv) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(9) For each pump designated facility, the information specified in paragraphs (b)(9)(i) through (iv) of this section in your initial annual report. Each annual report must contain the information specified in paragraphs (b)(9)(v) through (ix) of this section for each pump designated facility.

(i) The identification of each of your pumps that are driven by natural gas, as required by § 60.5395c(a) that allows traceability to the records required by paragraph (c)(14)(i) of this section.

(ii) For each pump designated facility for which there is a control device on site but it does not achieve a 95.0 percent emissions reduction, the certification that there is a control device available on site but it does not achieve a 95.0 percent emissions reduction required under § 60.5395c(b)(5). You must also report the emissions reduction percentage the control device is designed to achieve.

(iii) For each pump designated facility for which there is no control device or vapor recovery unit on site, the certification required under § 60.5395c(b)(6) that there is no control device or vapor recovery unit on site.

(iv) For each pump designated facility for which it is technically infeasible to route the emissions to a process or control device, the certification of technically infeasibility required under § 60.5395c(b)(7).

(v) For any pump designated facility which has previously reported as required under paragraphs (b)(9)(i) through (iv) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pump designated facility and the date that the pump designated facility meets one of the change conditions described in paragraphs (b)(9)(v)(A) through (C) of this section.

(A) If you install a control device or vapor recovery unit, you must report that a control device or vapor recovery unit has been added to the site and that the pump designated facility now is required to comply with § 60.5395c(b)(1) or (3), as applicable.

(B) If your pump designated facility previously complied with § 60.5395c(b)(1) or (3), as applicable, by routing emissions to a process or a control device and the process or control device is subsequently removed from the site or is no longer available such that there is no ability to route the emissions to a process or control device at the location, or that it is not technically feasible to capture and route the emissions to another control device or process located on site, report that you are no longer complying with the applicable requirements of § 60.5395c(b)(1) or (3) and submit the information provided in paragraphs (b)(9)(v)(B)(*1*) or (*2*) of this section.

(*1*) Certification that there is no control device or vapor recovery unit on site.

(*2*) Certification of the engineering assessment that it is technically infeasible to capture and route the emissions to another control device or process located on site.

(C) If any pump affected facility or individual natural gas-driven pump changes its method of compliance during the reporting period other than for the reasons specified in paragraphs (b)(9)(v)(A) and (B) of this section, identify the new compliance method for each natural gas-driven pump within the affected facility which changes its method of compliance during the reporting period and provide the applicable information specified in paragraphs (b)(9)(ii) through (iv) and (vi) through (viii) of this section for the new method of compliance.

(vi) For each pump designated facility complying with the requirements of § 60.5395c(a) or (b)(2) by routing the emissions to a process, you must report the information specified in paragraphs (b)(10)(i) through (iv) of this section.

(vii) For each pump designated facility complying with the requirements of § 60.5395c(b)(3) by routing the emissions to a control device, you must report the information required under paragraph (b)(10) of this section.

(viii) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(ix) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (b)(10)(i) and (ii) of this section, you must provide the information specified in § 60.5424c.

(10) For each well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment designated facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, you must submit the information in paragraphs (b)(10)(i) through (v) of this section. For each centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, or process unit equipment which uses a closed vent system to route to a process, you must submit the information in paragraphs (b)(10)(i) through (iv) of this section. For each centrifugal compressor, reciprocating compressor, and storage vessel equipped with a cover, you must submit the information in paragraphs (b)(10)(i) and (ii).

(i) Dates of each inspection required under § 60.5416c(a) and (b).

(ii) Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

(iii) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of § 60.5416c(a)(4).

(iv) You must submit the certification signed by the qualified professional engineer or in-house engineer according to § 60.5411c(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

(v) If you comply with the emissions standard for your well, centrifugal compressor, reciprocating compressor, storage vessel, process controller, pump, or process unit equipment designated facility with a control device, the information in paragraphs (b)(10)(v)(A) through (L) of this section, unless you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412c(d). If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412c(d), the information in paragraphs (b)(10)(v)(A) through (C) and (L) through (P) of this section.

(A) Identification of the control device.

(B) Make, model, and date of installation of the control device.

(C) Identification of the designated facility controlled by the device.

(D) For each continuous parameter monitoring system used to demonstrate compliance for the control device, a unique continuous parameter monitoring system identifier and the make, model number, and date of last calibration check of the continuous parameter monitoring system.

(E) For each instance where there is a deviation of the control device in accordance with § 60.5417c(g)(1) through (3) or (5) through (7) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.*, NHV operating limit, lack of pilot or combustion flame, condenser efficiency, bypass line flow, visible emissions), and cause of the deviation.

(F) For each instance where there is a deviation of the continuous parameter monitoring system in accordance with § 60.5417c(g)(4) include the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(G) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test or observation of the video surveillance output, the length of the observation in minutes, and the number of minutes for which visible emissions were present.

(H) If a performance test was conducted on the control device during the reporting period, provide the date the performance test was conducted. Submit the performance test report following the procedures specified in paragraph (b)(11) of this section.

(I) An indication of whether the enclosed combustion device or flare receives inert gases or other vent streams which may lower the NHV of the combined stream, and if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams. If a demonstration of the NHV of the inlet gas to the enclosed combustion device or flare was conducted during the reporting period in accordance with § 60.5417c(d)(8)(iii), an indication of whether this is a re-evaluation of vent gas NHV and the reason for the re-evaluation; the applicable required minimum vent gas NHV; if twice daily samples of the vent stream were taken, the number of samples with NHV values that are less than 1.2

times the applicable required minimum NHV, an indication of whether full one hour samples were collected or if shorter sampling times and, if shorter sampling times were used, the collection time(s) used and the reason for not obtaining a full one hour sample; if continuous NHV sampling of the vent stream was conducted, the number of hourly block average NHV values that are less than the required minimum vent gas NHV; if continuous combustion efficiency monitoring was conducted using an alternative test method approved under § 60.5412c(d), the number of values of the combustion efficiency that were less than 95.0 percent; the resulting determination of whether continuous NHV monitoring is required or not in accordance with § 60.5417c(d)(8)(iii)(D), (E), or (H); and if the enclosed combustion device or flare received inert gases or other vent streams which may lower the NHV of the combined stream, whether the sampling included periods where the highest percentage of inert gases or other vent streams which may lower the NHV of the combined stream were sent to the enclosed combustion device or flare.

(J) If a demonstration was conducted in accordance with § 60.5417c(d)(8)(iv) that the maximum potential pressure of units manifolded to an enclosed combustion device or flare cannot cause the maximum inlet flow rate established in accordance with § 60.5417c(f)(1) or a flare tip velocity limit of 18.3 meter/second (60 feet/second) to be exceeded, an indication of whether this is a re-evaluation of the gas flow and the reason for the re-evaluation; the demonstration conducted; and applicable engineering calculations.

(K) For each periodic sampling event conducted under § 60.5417c(d)(8)(iii)(G), provide the date of the sampling, the required minimum vent gas NHV, and the NHV value for each vent gas sample.

(L) For each flare and enclosed combustion device, provide the date each device is observed with OGI in accordance with § 60.5415c(e)(1)(x) and whether uncombusted emissions were present. Provide the date each device was visibly observed during an AVO inspection in accordance with § 60.5415c(e)(1)(x), whether the pilot or combustion flame was lit at the time of observation, and whether the device was found to be operating properly.

(M) An identification of the alternative test method used.

(N) For each instance where there is a deviation of the control device in accordance with § 60.5417c(i)(6)(i) or (iii) through (v) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (*e.g.*, destruction efficiency below 95 percent, lack of pilot or combustion flame, visible emissions), and cause of the deviation.

(O) For each instance where there is a deviation of the data availability in accordance with § 60.5417c(i)(6)(ii) include the date of each operating day when monitoring data are not available for at least 75 percent of the operating hours.

(P) If no deviations occurred under paragraph (b)(10)(v)(N) or (O) of this section, a statement that there were no deviations for the control device during the annual report period.

(Q) Any additional information required to be reported as specified by the Administrator as part of the alternative test method approval under § 60.5412c(d).

(11) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413c(d), you must submit the results of the performance test following the procedures specified in paragraph (d) of this section. Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(12) For combustion control devices tested by the manufacturer in accordance with § 60.5413c(d), an electronic copy of the performance test results required by § 60.5413c(d) shall be submitted via email to *Oil__and__Gas__PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

(13) If you had a super-emitter event during the reporting period, the start date of the super-emitter event, the duration of the super-emitter event in hours, and the designated facility associated with the super-emitter event, if applicable.

(14) You must submit your annual report using the appropriate electronic report template on the Compliance and Emissions Data Reporting Interface (CEDRI) website for this subpart and following the procedure specified in paragraph (d) of this section. If

the reporting form specific to this subpart is not available on the CEDRI website at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(c) *Recordkeeping requirements*. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (14) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(1) For each gas well liquids unloading operation at your well designated facility that is subject to § 60.5390c(a)(1) or (2), the records of each gas well liquids unloading operation conducted during the reporting period, including the information specified in paragraphs (c)(1)(i) through (iii) of this section, as applicable.

(i) For each gas well liquids unloading operation that complies with § 60.5390c(a)(1) by performing all liquids unloading events without venting of methane emissions to the atmosphere, comply with the recordkeeping requirements specified in paragraphs (c)(1)(i)(A) and (B) of this section.

(A) Identification of each well (*i.e.*, U.S. Well ID or U.S. Well ID associated with the well designated facility) that conducts a gas well liquids unloading operation during the reporting period without venting of methane emissions and the non-venting gas well liquids unloading method used. If more than one non-venting method is used, you must maintain records of all the differing non-venting liquids unloading methods used at the well designated facility complying with § 60.5390c(a)(1).

(B) Number of events where unplanned emissions are vented to the atmosphere during a gas well liquids unloading operation where you complied with best management practices to minimize emissions to the maximum extent possible.

(ii) For each gas well liquids unloading operation that complies with § 60.5390c(b) and (c) best management practices, maintain records documenting information specified in paragraphs (c)(1)(ii)(A) through (D) of this section.

(A) Identification of each well designated facility that conducts liquids unloading during the reporting period that employs best management practices to minimize emissions to the maximum extent possible.

(B) Documentation of your best management practice plan developed under paragraph § 60.5390c(c). You may update your best management practice plan to include additional steps which meet the criteria in § 60.5390c(c).

(C) A log of each best management practice plan step taken to minimize emissions to the maximum extent possible for each gas well liquids unloading event.

(D) Documentation of each gas well liquids unloading event where deviations from your best management practice plan steps occurred, the date and time the deviation began, the duration of the deviation, documentation of best management practice plans steps were not followed, and the steps taken in lieu of your best management practice plan steps during those events to minimize emissions to the maximum extent possible.

(iii) For each well designated facility that reduces methane emissions from well designated facility gas wells that unload liquids by 95.0 percent by routing emissions to a control device through closed vent system under § 60.5390c(g), you must maintain the records in paragraphs (c)(1)(iii)(A) through (E) of this section.

(A) If you comply with the emission reduction standard with a control device, the information for each control device in paragraph (c)(10) of this section.

(B) Records of the closed vent system inspection as specified paragraph (c)(7) of this section.

(C) Records of the cover inspections as specified in paragraph (c)(8) of this section.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(9) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(11) of this section.

(2) For each associated gas well, you must maintain the applicable records specified in paragraphs (c)(2)(i) or (ii) and (iii), (iv), (v), (vi) and (vii) of this section, as applicable.

(i) For each associated gas well that complies with the requirements of § 60.5391c(a)(1), (2), (3), or (4), you must keep the records specified in paragraphs (c)(2)(i)(A) and (B) of this section.

(A) Documentation of the specific method(s) in § 60.5391c(a)(1), (2), (3), or (4) that was used.

(B) For instances where you temporarily route the associated gas to a flare or control device in accordance with § 60.5391c(c), you must keep the records specified in paragraphs (c)(2)(i)(B)(*1*) through (*3*) of this section.

(*1*) The reason in § 60.5391c(c)(1), (2), (3), or (4) for each incident.

(2) The date of each incident, along with the times when routing the associated gas to the flare or control device started and ended, along with the total duration of each incident.

(3) Documentation that all CVS requirements specified in § 60.5411c(a) and (c) and all applicable flare or control device requirements specified in § 60.5412c are met during each period when the associated gas is routed to the flare or control device.

(ii) For instances where you temporarily vent the associated gas in accordance with § 60.5391c(d), you must keep the records specified in paragraphs (c)(2)(ii)(A) through (D) of this section. These records are required if you are routinely complying with § 60.5391c(a) or § 60.5391c(b) or temporarily complying with § 60.5391c(c).

(A) The reason in § 60.5391c(d)(1), (2), or (3) for each incident.

(B) The date of each incident, along with the times when venting the associated gas started and ended, along with the total duration of each incident.

(C) The methane emissions that were emitted during each incident.

(D) The cumulative duration of venting incidents and methane emissions for all incidents in each calendar year.

(iii) For each associated gas well that complies with the requirements of § 60.5391c(b) because it has demonstrated that annual methane emissions are 40 tons per year or less at the initial compliance date, maintain records of the calculation of annual methane emissions determined in accordance with § 60.5391c(e)(1).

(iv) For each associated gas well at your well that complies with the requirements of § 60.5391c(b) because it has demonstrated that it is not feasible to comply with § 60.5391c(a)(1), (2), (3), or (4) due to technical reasons, records of each annual demonstration and certification of the technical reason that it is not feasible to comply with § 60.5391c(a)(1) through (4) in accordance with § 60.5391c(b)(2)(i) through (iii), as well as the records required by paragraph (c)(2)(v) of this section.

(v) For each associated gas well that complies with the requirements of § 60.5391c(b) by routing your associated gas to a flare or control device that achieves a 95.0 reduction in methane emissions, the records in paragraphs (c)(2)(v)(A) through (E) of this section.

(A) Identification of each instance when associated gas was vented and not routed to a control device that reduces methane emissions by at least 95.0 percent in accordance with paragraph (c)(2)(iii) of this section.

(B) If you comply with the emission reduction standard in § 60.5391c with a control device, the information for each control device in paragraph (c)(10) of this section.

(C) Records of the closed vent system inspection as specified paragraph (c)(7) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (c)(7) of this section, you must maintain records of the information specified in § 60.5424c.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(9) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(11) of this section.

(vi) For each instance where you route associated gas to a flare or control device for beyond 72 hours due to an "exigent circumstance" according to § 60.5391c(c)(1) or (2), you must maintain the records specified in paragraphs (c)(2)(vi)(A) through (D) of this section.

(A) A written description of the “exigent circumstance” requiring the need to flare or route to a control device beyond 72 hours.

(B) A description of steps taken to resolve the need for temporary flaring/routing to a control device;

(C) The dates and times an identified "exigent circumstance" started and ended (*e.g.*, when owners or operators are able to access site, when personnel and/or equipment are available) and the total duration of each "exigent circumstance"; and

(D) The dates and times temporary flaring/routing to a control device started and ended and the total duration of temporary flaring/routing to a control device due to the identified "exigent circumstance."

(vii) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(3) For each centrifugal compressor designated facility, you must maintain the records specified in paragraphs (c)(3)(i) through (iii) of this section.

(i) For each centrifugal compressor designated facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5392c, including a description of each deviation, the date and time each deviation began and the duration of each deviation.

(ii) For each wet seal compressor complying with the emissions reduction standard in § 60.5392c(a)(3) and (4), you must maintain the records in paragraphs (c)(3)(ii)(A) through (E) of this section. For each wet seal compressor complying with the alternative standard in § 60.5392c(a)(3) and (5) by routing the closed vent system to a process, you must maintain the records in paragraphs (c)(3)(ii)(B) through (E) of this section.

(A) If you comply with the emission reduction standard in § 60.5392c(a)(3) and (4) with a control device, the information for each control device in paragraph (c)(10) of this section.

(B) Records of the closed vent system inspection as specified paragraph (c)(7) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (c)(7) of this section, you must maintain records of the information specified in § 60.5424c.

(C) Records of the cover inspections as specified in paragraph (c)(8) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(8) of this section, you must maintain the information specified in § 60.5424c.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(9) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(11) of this section.

(iii) For each centrifugal compressor designated facility using dry seals or wet seals and each self-contained wet seal centrifugal compressor and complying with the standard in § 60.5392c(a)(1) and (2), you must maintain the records specified in paragraphs (c)(3)(iii)(A) through (H) of this section.

(A) Records of the cumulative number of hours of operation since initial startup, since 36 months after the state plan submittal deadline (as specified in § 60.5362c(c)), or since the previous volumetric flow rate measurement, as applicable.

(B) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(C) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(3)(iii)(C)(*1*) through (*6*) of this section.

(*1*) Description of standard method published by a consensus-based standards organization or industry standard practice.

(*2*) Records of volumetric flow rate emissions calculations conducted according to § 60.5392c(a)(2), as applicable.

(*3*) Records of manufacturer operating procedures and measurement methods.

(*4*) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration and accuracy checks.

(*5*) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(*6*) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(D) Date when performance-based volumetric flow rate is exceeded.

(E) The date of successful repair of the compressor seal, including follow-up performance-based volumetric flow rate measurement to confirm successful repair .

(F) Identification of each compressor seal placed on delay of repair and explanation for each delay of repair.

(G) For each compressor seal or part needed for repair placed on delay of repair because of replacement seal or part unavailability, the operator must document: the date the seal or part was added to the delay of repair list, the date the replacement seal or part was ordered, the anticipated seal or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the seal or part.

(H) Date of planned shutdowns that occur while there are any seals or parts that have been placed on delay of repair.

(4) For each reciprocating compressor designated facility, you must maintain the records in paragraphs (c)(4)(i) through (x) and (c)(7) through (12) of this section, as applicable. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7) of this section, you must provide the information specified in § 60.5424c.

(i) For each reciprocating compressor designated facility, you must maintain records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5393c, including a description of each deviation, the date and time each deviation began and the duration of each deviation in hours.

(ii) Records of the date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5393c(d), where applicable.

(iii) Records of the cumulative number of hours of operation since initial startup, since 36 months after the state plan submittal deadline (as specified in § 60.5362c(c)), or since the previous volumetric flow rate measurement, as applicable. Alternatively, a record that emissions from the rod packing are being routed to a process through a closed vent system.

(iv) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(v) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(4)(v)(A) through (F) of this section.

(A) Description of standard method published by a consensus-based standards organization or industry standard practice.

(B) Records of volumetric flow rate calculations conducted according to paragraphs § 60.5393c(b) or (c), as applicable.

(C) Records of manufacturer's operating procedures and measurement methods.

(D) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration and accuracy checks.

(E) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(F) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(vi) Date when performance-based volumetric flow rate is exceeded.

(vii) The date of successful replacement or repair of reciprocating compressor rod packing, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

(viii) Identification of each reciprocating compressor placed on delay of repair because of rod packing or part unavailability and explanation for each delay of repair.

(ix) For each reciprocating compressor that is placed on delay of repair because of replacement rod packing or part unavailability, the operator must document: the date the rod packing or part was added to the delay of repair list, the date the replacement rod packing or part was ordered, the anticipated rod packing or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the rod packing or part.

(x) Date of planned shutdowns that occur while there are any reciprocating compressors that have been placed on delay of repair due to the unavailability of rod packing or parts to conduct repairs.

(5) For each process controller designated facility, you must maintain the records specified in paragraphs (c)(5)(i) through (vii) of this section.

(i) Records identifying each process controller that is driven by natural gas and that does not function as an emergency shutdown device.

(ii) For each process controller designated facility complying with § 60.5394c(a), you must maintain records of the information specified in paragraphs (c)(5)(ii)(A) and (B) of this section, as applicable.

(A) If you are complying with § 60.5394c(a) by routing process controller vapors to a process through a closed vent system, you must report the information specified in paragraphs (c)(5)(ii)(A)(*1*) and (*2*) of this section.

(*1*) An identification of all the natural gas-driven process controllers in the process controller designated facility for which you collect and route vapors to a process through a closed vent system.

(*2*) The records specified in paragraphs (c)(7), (9), and (11) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7) of this section, you must provide the information specified in § 60.5424c.

(B) If you are complying with § 60.5394c(a) by using a self-contained natural gas-driven process controller, you must report the information specified in paragraphs (c)(5)(ii)(B)(*1*) through (*3*) of this section.

(*1*) An identification of each process controller complying with § 60.5394c(a) by using a self-contained natural gas-driven process controller;

(*2*) Dates of each inspection required under § 60.5416c(b); and

(*3*) Each defect or leak identified during each natural gas-driven-self-contained process controller system inspection, and date of repair or date of anticipated repair if repair is delayed.

(iii) For each process controller designated facility complying with § 60.5394c(b)(1) process controller bleed rate requirements, you must maintain records of the information specified in paragraphs (c)(5)(iii)(A) and (B) of this section.

(A) The identification of process controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh and records of the manufacturer's specifications indicating that the process controller is designed with a natural gas bleed rate of less than or equal to 6 scfh.

(B) Where necessary to meet a functional need, the identification of the process controller and demonstration of why it is necessary to use a process controller with a natural gas bleed rate greater than 6 scfh.

(iv) For each intermittent vent process controller in the designated facility complying with the requirements in § 60.5394c(b)(2), you must keep records of the information specified in paragraphs (c)(5)(iv)(A) through (C) of this section.

(A) The identification of each intermittent vent process controller.

(B) Dates and results of the intermittent vent process controller monitoring required by § 60.5394c(b)(2)(ii).

(C) For each instance in which monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, the date of repair or replacement, or the date of anticipated repair or replacement if the repair or replacement is delayed and the date and results of the re-survey after repair or replacement.

(v) For each process controller designated facility complying with § 60.5394c(b)(3), you must maintain the records specified in paragraphs (c)(5)(v)(A) and (B) of this section.

(A) An identification of each process controller for which emissions are routed to a control device.

(B) Records specified in paragraphs (c)(7) and (9) through (12) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (c)(7) of this section, you must provide the information specified in § 60.5424c.

(vi) Records of each change in compliance method, including identification of each natural gas-driven process controller which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(vii) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(6) For each storage vessel designated facility, you must maintain the records identified in paragraphs (c)(6)(i) through (vii) of this section.

(i) You must maintain records of the identification and location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983 of each storage vessel designated facility.

(ii) Records of each methane emissions determination for each storage vessel designated facility made under § 60.5386c(e) including identification of the model or calculation methodology used to calculate the methane emission rate.

(iii) For each instance where the storage vessel was not operated in compliance with the requirements specified in § 60.5396c, a description of the deviation, the date and time each deviation began, and the duration of the deviation.

(iv) If complying with the emissions reduction standard in § 60.5396c(a)(1), you must maintain the records in paragraphs (c)(6)(iv)(A) through (E) of this section.

(A) If you comply with the emission reduction standard with a control device, the information for each control device in paragraph (c)(10) of this section.

(B) Records of the closed vent system inspection as specified paragraph (c)(7) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7) of this section, you must provide the information specified in § 60.5424c.

(C) Records of the cover inspections as specified in paragraph (c)(8) of this section. If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraph (c)(8) of this section, you must provide the information specified in § 60.5424c.

(D) If applicable, the records of bypass monitoring as specified in paragraph (c)(9) of this section.

(E) Records of the closed vent system assessment as specified in paragraph (c)(11) of this section.

(v) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), records indicating the number of consecutive days that the vessel is located at a site in the crude oil and natural gas source category. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(vi) Records of the date that each storage vessel designated facility or portion of a storage vessel designated facility is removed from service and returned to service, as applicable.

(vii) Records of the date that liquids from the well following fracturing or refracturing are routed to the storage vessel designated facility; or the date that you comply with paragraph § 60.5396c(a)(2), following a monthly emissions determination which indicates that methane emissions increase to 14 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel designated facility, and records of the methane emissions rate and the model or calculation methodology used to calculate the methane emission rate.

(7) Records of each closed vent system inspection required under § 60.5416c(a)(1) and (2) and (b) for your well, centrifugal compressor, reciprocating compressor, process controller, pump, storage vessel, and process unit equipment designated facility as required in paragraphs (c)(7)(i) through (iv) of this section.

(i) A record of each closed vent system inspection or no identifiable emissions monitoring survey. You must include an identification number for each closed vent system (or other unique identification description selected by you), the date of the inspection, and the method used to conduct the inspection (*i.e.*, visual, AVO, OGI, Method 21 of appendix A-7 to this part).

(ii) For each defect or emissions detected during inspections required by § 60.5416c(a)(1) and (2), or (b) you must record the location of the defect or emissions; a description of the defect; the maximum concentration reading obtained if using Method 21 of appendix A-7 to this part; the indication of emissions detected by AVO if using

AVO; the date of detection; the date of each attempt to repair the emissions or defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect or emissions is completed.

(iii) If repair of the defect is delayed as described in § 60.5416c(b)(6), you must record the reason for the delay and the date you expect to complete the repair.

(iv) Parts of the closed vent system designated as unsafe to inspect as described in § 60.5416c(b)(7) or difficult to inspect as described in § 60.5416c(b)(8), the reason for the designation, and written plan for inspection of that part of the closed vent system.

(8) A record of each cover inspection required under § 60.5416c(a)(3) for your centrifugal compressor, reciprocating compressor, or storage vessel as required in paragraphs (c)(8)(i) through (iv) of this section.

(i) A record of each cover inspection. You must include an identification number for each cover (or other unique identification description selected by you), the date of the inspection, and the method used to conduct the inspection (*i.e.*, AVO, OGI, Method 21 of appendix A-7 to this part).

(ii) For each defect detected during the inspection you must record the location of the defect; a description of the defect; the date of detection; the maximum concentration reading obtained if using Method 21 of appendix A-7 to this part; the indication of emissions detected by AVO if using AVO; the date of each attempt to repair the defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect is completed.

(iii) If repair of the defect is delayed as described in § 60.5416c(b)(5), you must record the reason for the delay and the date you expect to complete the repair.

(iv) Parts of the cover designated as unsafe to inspect as described in § 60.5416c(b)(7) or difficult to inspect as described in § 60.5416c(b)(8), the reason for the designation, and written plan for inspection of that part of the cover.

(9) For each bypass subject to the bypass requirements of § 60.5416c(a)(4), you must maintain a record of the following, as applicable: readings from the flow indicator; each inspection of the seal or closure mechanism; the date and time of each instance the key is checked out; date and time of each instance the alarm is sounded.

(10) Records for each control device used to comply with the emission reduction standard in § 60.5391c(b) for associated gas wells, § 60.5392c(a)(4) for centrifugal compressor designated facilities, § 60.5393c(d)(2) for reciprocating compressor designated facilities, § 60.5394c(b)(3) for your process controller designated facility in Alaska, § 60.5395c(b)(3) for your pump designated facility, § 60.5396c(a)(2) for your storage vessel designated facility, § 60.5390c(g) for well designated facility gas well liquids unloading, or § 60.5400c(f) or 60.5401c(e) for your process equipment designated facility, as required in paragraphs (c)(10)(i) through (viii) of this section. If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412c(d), keep records of the information in paragraph (c)(10)(ix) of this section, in lieu of the records required by paragraphs (c)(10)(i) through (iv) and (vi) through (viii) of this section.

(i) For a control device tested under § 60.5413c(d) which meets the criteria in § 60.5413c(d)(11) and (e), keep records of the information in paragraphs (c)(10)(i)(A) through (E) of this section, in addition to the records in paragraphs (c)(10)(ii) through (ix) of this section, as applicable.

(A) Serial number of purchased device and copy of purchase order.

(B) Location of the designated facility associated with the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(C) Minimum and maximum inlet gas flow rate specified by the manufacturer.

(D) Records of the maintenance and repair log as specified in § 60.5413c(e)(4), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(ii) For all control devices, keep records of the information in paragraphs (c)(10)(ii)(A) through (G) of this section, as applicable.

(A) Make, model, and date of installation of the control device, and identification of the designated facility controlled by the device.

(B) Records of deviations in accordance with § 60.5417c(g)(1) through (7), including a description of the deviation, the date and time the deviation began, the duration of the deviation, and the cause of the deviation.

(C) The monitoring plan required by § 60.5417c(c)(2).

(D) Make and model number of each continuous parameter monitoring system.

(E) Records of minimum and maximum operating parameter values, continuous parameter monitoring system data (including records that the pilot or combustion flame is present at all times), calculated averages of continuous parameter monitoring system data, and results of all compliance calculations.

(F) Records of continuous parameter monitoring system equipment performance checks, system accuracy audits, performance evaluations, or other audit procedures and results of all inspections specified in the monitoring plan in accordance with § 60.5417c(c)(2). Records of calibration gas cylinders, if applicable.

(G) Periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities. Records of repairs on the monitoring system.

(iii) For each carbon adsorption system, records of the schedule for carbon replacement as determined by the design analysis requirements of § 60.5413c(c)(2) and (3) and records of each carbon replacement as specified in §§ 60.5412c(c)(1) and 60.5415c(e)(1)(viii).

(iv) For enclosed combustion devices and flares, records of visible emissions observations as specified in paragraph (c)(10)(iv)(A) or (B) of this section.

(A) Records of observations with Method 22 of appendix A-7 to this part, including observations required following return to operation from a maintenance or repair activity, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in Method 22 of appendix A-7 to this part.

(B) If you monitor visible emissions with a video surveillance camera, location of the camera and distance to emission source, records of the video surveillance output, and documentation that an operator looked at the feed daily, including the date and start time of observation, the length of observation, and length of time visible emissions were present.

(v) For enclosed combustion devices and flares, video of the OGI inspection conducted in accordance with § 60.5415c(e)(1)(x). Records documenting each enclosed combustion device and flare was visibly observed during each inspection conducted under § 60.5397c using AVO in accordance with § 60.5415c(e)(1)(x).

(vi) For enclosed combustion devices and flares, an indication of whether the enclosed combustion device or flare receives inert gases or other vent streams which may lower the NHV of the combined stream, and if so, a description of the operating scenario(s) which may lower the NHV of the combined stream through the introduction of inert gases or other vent gas streams. Records of each demonstration of the NHV of the inlet gas to the enclosed combustion device or flare conducted in accordance with § 60.5417c(d)(8)(iii), including the sampling approach used (continuous NHV, twice daily sampling, alternative method), the date, time and results of each analysis, and, if shorter sampling times were used with twice daily sampling, the collection time(s) used and the reason for not obtaining a full one hour sample. For each re-evaluation of the NHV of the inlet gas, records of process changes and explanation of the conditions that led to the need to re-evaluation the NHV of the inlet gas. For each demonstration where the enclosed combustion device or flare received inert gases, record the highest percentage of inert gases that can be sent to the enclosed combustion device or flare and the highest percent of inert gases sent to the enclosed combustion device or flare during the NHV demonstration. Records of periodic sampling conducted under § 60.5417c(d)(8)(iii)(G).

(vii) For enclosed combustion devices and flares, if you use a backpressure regulator valve, the make and model of the valve, date of installation, and record of inlet flow rating. Maintain records of the engineering evaluation and manufacturer specifications that identify the pressure set point corresponding to the minimum inlet gas flow rate, the annual confirmation that the backpressure regulator valve set point is correct and consistent with the engineering evaluation and manufacturer specifications, and the annual confirmation that the backpressure regulator valve fully closes when not in open position.

(viii) For enclosed combustion devices and flares, records of each demonstration required under § 60.5417c(d)(8)(iv).

(ix) If you use an enclosed combustion device or flare using an alternative test method approved under § 60.5412c(d), keep records of the information in paragraphs (c)(10)(ix)(A) through (H) of this section, in lieu of the records required by paragraphs (c)(10)(i) through (iv) and (vi) through (viii) of this section.

(A) An identification of the alternative test method used.

(B) Data recorded at the intervals required by the alternative test method.

(C) Monitoring plan required by § 60.5417c(i)(2).

(D) Quality assurance and quality control activities conducted in accordance with the alternative test method.

(E) If required by § 60.5412c(d)(4) to conduct visible emissions observations, records required by paragraph (c)(10)(iv) of this section.

(F) If required by § 60.5412c(d)(5) to conduct pilot or combustion flame monitoring, record indicating the presence of a pilot or combustion flame and periods when the pilot or combustion flame is absent.

(G) For each instance where there is a deviation of the control device in accordance with § 60.5417c(i)(6)(i) through (v), the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation.

(H) Any additional information required to be recorded as specified by the Administrator as part of the alternative test method approval under § 60.5412c(d).

(11) For each closed vent system routing to a control device or process, the records of the assessment conducted according to § 60.5411c(c):

(i) A copy of the assessment conducted according to § 60.5411c(c)(1); and

(ii) A copy of the certification according to § 60.5411c(c)(1)(i) and (ii).

(12) A copy of each performance test submitted under paragraph (b)(11) or (12) of this section.

(13) For the fugitive emissions components designated facility, maintain the records identified in paragraphs (c)(13)(i) through (vii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for the fugitive emissions components designated facility at a well site and the date of startup or the date of modification for the fugitive emissions components designated facility at a compressor station.

(ii) For the fugitive emissions components designated facility at a well site, you must maintain records specifying what type of well site it is (*i.e.*, single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment.)

(iii) For the fugitive emissions components designated facility at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

(iv) The fugitive emissions monitoring plan as required in § 60.5397c(b) through (d).

(v) The records of each monitoring survey as specified in paragraphs (c)(13)(v)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument or method used.

(E) Fugitive emissions component identification when Method 21 of appendix A-7 to this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (*i.e.*, operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

(G) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(H) Records of calibrations for the instrument used during the monitoring survey.

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(13)(v)(I)(*1*) through (*9*) of this section.

(*1*) Location of each fugitive emission identified.

(*2*) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(*3*) If Method 21 of appendix A-7 to this part is used for detection, record the component ID and instrument reading.

(*4*) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.*, tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(*5*) The date of first attempt at repair of the fugitive emissions component(s).

(*6*) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

(*7*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair.

(*8*) For each fugitive emission component placed on delay of repair for reason of replacement component unavailability, the operator must document: the date the component was added to the delay of repair list, the date the replacement fugitive component or part thereof was ordered, the anticipated component delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the component.

(*9*) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(vi) For well closure activities, you must maintain the information specified in paragraphs (c)(13)(vi)(A) through (G) of this section.

(A) The well closure plan developed in accordance with § 60.5397c(l) and the date the plan was submitted.

(B) The notification of the intent to close the well site and the date the notification was submitted.

(C) The date of the cessation of production from all wells at the well site.

(D) The date you began well closure activities at the well site.

(E) Each status report for the well closure activities reported in paragraph (b)(8)(iv)(A) of this section.

(F) Each OGI survey reported in paragraph (b)(8)(iv)(B) of this section including the date, the monitoring instrument used, and the results of the survey or resurvey.

(G) The final OGI survey video demonstrating the closure of all wells at the site. The video must include the date that the video was taken and must identify the well site location by latitude and longitude.

(vii) If you comply with an alternative GHG standard under § 60.5398c, in lieu of the information specified in paragraphs (c)(13)(iv) and (v) of this section, you must maintain the records specified in § 60.5424c.

(14) For each pump designated facility, you must maintain the records identified in paragraphs (c)(14)(i) through (ix) of this section, as applicable.

(i) Identification of each pump that is driven by natural gas and that is in operation 90 days or more per calendar year.

(ii) If you are complying with § 60.5395c(a) or (b)(1) by routing pump vapors to a process through a closed vent system, identification of all the natural gas-driven pumps in the pump designated facility for which you collect and route vapors to a process through a closed vent system and the records specified in paragraphs (c)(7), (9), and (11) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7) of this section, you must provide the information specified in § 60.5424c.

(iii) If you are complying with § 60.5395c(b)(1) by routing pump vapors to control device achieving a 95.0 percent reduction in methane emissions, you must keep the records specified in paragraphs (c)(7) and (9) through (12) of this section. If you comply with an alternative GHG and VOC standard under § 60.5398c, in lieu of the information specified in paragraph (c)(7), you must provide the information specified in § 60.5424c.

(iv) If you are complying with § 60.5395c(b)(3) by routing pump vapors to a control device achieving less than a 95.0 percent reduction in methane emissions, you must maintain records of the certification that there is a control device on site but it does not achieve a 95.0 percent emissions reduction and a record of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(v) If you have less than three natural gas-driven diaphragm pumps in the pump designated facility, and you do not have a vapor recovery unit or control device installed on site by the compliance date, you must retain a record of your certification required under § 60.5395c(b)(4), certifying that there is no vapor recovery unit or control device on site. If you subsequently install a control device or vapor recovery unit, you must maintain the records required under paragraphs (c)(14)(ii) and (iii) or (iv) of this section, as applicable.

(vi) If you determine, through an engineering assessment, that it is technically infeasible to route the pump designated facility emissions to a process or control device, you must retain records of your demonstration and certification that it is technically infeasible as required under § 60.5395c(b)(7).

(vii) If the pump is routed to a process or control device that is subsequently removed from the location or is no longer available such that there is no option to route to a process or control device, you are required to retain records of this change and the records required under paragraph (c)(14)(vi) of this section.

(viii) Records of each change in compliance method, including identification of each natural gas-driven pump which changes its method of compliance, the new method of compliance, and the date of the change in compliance method.

(ix) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(d) *Electronic reporting.* If you are required to submit notifications or reports following the procedure specified in this paragraph (d), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (d)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described in this paragraph (d).

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