ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2010–0682; FRL–9976–00–OAR]

RIN 2060–AT50

National Emission Standards for Hazardous Air Pollutants and New Source Performance Standards: Petroleum Refinery Sector Amendments

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) Refinery MACT 1 and Refinery MACT 2 regulations to clarify the requirements of these rules and to make technical corrections and minor revisions to requirements for work practice standards, recordkeeping and reporting. This action also proposes technical corrections for the New Source Performance Standards (NSPS) for Petroleum Refineries.

DATES: *Comments.* Comments must be received on or before May 25, 2018.

Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before May 10, 2018.

Public Hearing. If a public hearing is requested by April 16, 2018, then we will hold a public hearing on April 25, 2018 at the location described in the **ADDRESSES** section. The last day to pre-register in advance to speak at the public hearing will be April 23, 2018.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2010–0682, at *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov. Regulations.gov* is our preferred method of receiving comments. However, other submission formats are accepted. To ship or send mail via the United States Postal Service, use the following address: U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2010–0682, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460. Use the following Docket Center address if you are using express mail, commercial delivery, hand delivery, or courier: EPA Docket Center, EPA WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. Delivery verification signatures will be available only during regular business hours.

Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. See section I.C of this preamble for instructions on submitting CBI.

The EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www2.epa.gov/dockets/commenting-epa-dockets.*

Public Hearing. If a public hearing is requested, it will be held at EPA Headquarters, EPA WJC East Building, 1201 Constitution Avenue NW, Washington, DC 20004. If a public hearing is requested, then we will provide details about the public hearing on our website at: *https://www.epa.gov/stationary-sources-air-pollution/petroleum-refinery-sector-risk-and-technology-review-and-new-source.* The EPA does not intend to publish another document in the **Federal Register** announcing any updates on the request for a public hearing. Please contact Virginia Hunt at (919) 541–0832 or by email at *hunt.virginia@epa.gov* to request a public hearing, to register to speak at the public hearing, or to inquire as to whether a public hearing will be held.

The EPA will make every effort to accommodate all speakers who arrive and register. If a hearing is held at a U.S. government facility, individuals planning to attend should be prepared to show a current, valid state- or federal-approved picture identification to the security staff in order to gain access to the meeting room. An expired form of identification will not be permitted. Please note that the Real ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. If your driver's license is issued by a noncompliant state, you must present an additional form of identification to enter a federal facility. Acceptable alternative forms of identification include: Federal employee badge, passports, enhanced driver's licenses, and military identification cards. Additional information on the Real ID Act is available at *https://www.dhs.gov/real-id-frequently-asked-questions.* In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building, and demonstrations will not be allowed on federal property for security reasons.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Brenda Shine, Sector Policies and Programs Division (E143–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–3608; fax number: (919) 541–0516; and email address: *shine.brenda@epa.gov.* For information about the applicability of the NESHAP to a particular entity, contact Ms. Maria Malave, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, EPA WJC South Building (Mail Code 2227A), 1200 Pennsylvania Avenue NW, Washington, DC 20460; telephone number: (202) 564–7027; and email address: *malave.maria@epa.gov.*

SUPPLEMENTARY INFORMATION:

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2010–0682. All documents in the docket are listed in the *Regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* 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. Publicly available docket materials are available either electronically in *Regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2010–0682. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. This type of information should be submitted by mail as discussed in section I.C of this preamble. The *http://www.regulations.gov* website is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *http://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/dockets.*

Preamble Acronyms and Abbreviations. 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:

AFPM American Fuel and Petrochemical Manufacturers
API American Petroleum Institute
AWP Alternative Work Practice
CAA Clean Air Act
CBI Confidential Business Information
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS continuous emission monitoring system
CFR Code of Federal Regulations
COMS continuous opacity monitoring system
CPMS continuous parameter monitoring system
CRU catalytic reforming unit
DCU delayed coking unit
EPA Environmental Protection Agency
ERT Electronic Reporting Tool
FCCU fluid catalytic cracking unit
FR Federal Register
HAP hazardous air pollutant(s)
HCN hydrogen cyanide
HON hazardous organic NESHAP
LEL lower explosive limit
MACT maximum achievable control technology
NESHAP national emission standards for hazardous air pollutants
NOCS Notification of Compliance Status
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OAQPS Office of Air Quality Planning and Standards
OEL open-ended lines
OMB Office of Management and Budget
PDF portable document format
PM particulate matter
PRA Paperwork Reduction Act
PRD pressure relief device
RFA Regulatory Flexibility Act
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act

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

I. General Information

A. Does this action apply to me?

Table 1 of this preamble lists the NESHAP, NSPS, and associated regulated industrial source categories that are the subject of this proposal. Table 1 is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this proposed action is likely to affect. The proposed standards, once promulgated, will be directly applicable to the affected sources. Federal, state, local, and tribal government entities would not be affected by this proposed action. As defined in the *Initial List of Categories of Sources Under Section 112(c)(1) of the Clean Air Act Amendments of 1990* (see 57 FR 31576, July 16, 1992), the Petroleum Refineries—Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plant Units source category includes any facility engaged in producing gasoline, napthas, kerosene, jet fuels, distillate fuel oils, residual fuel oils, lubricants, or other products from crude oil or unfinished petroleum derivatives. This category includes the following refinery process units: Catalytic cracking (fluid and other) units, catalytic reforming units, and sulfur plant units. The Petroleum Refineries—Other Sources Not Distinctly Listed includes any facility engaged in producing gasoline, napthas, kerosene, jet fuels, distillate fuel oils, residual fuel oils, lubricants, or other products from crude oil or unfinished petroleum derivatives. This category includes the following refinery process units not listed in the Petroleum Refineries—Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plant Units source category. The refinery process units in this source category include, but are not limited to, thermal cracking, vacuum distillation, crude distillation, hydroheating/hydrorefining, isomerization, polymerization, lube oil processing, and hydrogen production.

TABLE 1—NESHAP AND INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS PROPOSED ACTION

Source category	NESHAP	NAICS code [1]
Petroleum Refineries.	40 CFR part 63, subpart CC. 40 CFR part 63, subpart UUU. 40 CFR part 60, subpart Ja.	324110

[1] North American Industry Classification System.

B. 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. Following signature by the EPA Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/stationary-sources-air-pollution/petroleum-refinery-sector-risk-and-technology-review-and-new-source.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same website.

A redline version of the regulatory language that incorporates the proposed changes in this action is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2010–0682).

C. What should I consider as I prepare my comments for the EPA?

Submitting CBI. Do not submit information containing CBI to the EPA through *http://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI for inclusion in the public docket. If you submit a CD–ROM or disk that does not contain CBI, mark the outside of the disk or CD–ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2. Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2010–0682.

II. Background

On December 1, 2015 (80 FR 75178), the EPA finalized amendments to the Petroleum Refinery NESHAP in 40 CFR part 63, subparts CC and UUU, referred to as Refinery MACT 1 and 2, respectively and the NSPS for petroleum refineries in 40 CFR part 60, subparts J and Ja. The final amendments to Refinery MACT 1 include a number of new requirements, such as those for maintenance vents, pressure relief devices (PRDs), delayed coking units (DCUs), fenceline monitoring, and flares. The final amendments to Refinery MACT 2 include revisions to the continuous compliance alternatives for catalytic cracking units and provisions specific to startup and shutdown of catalytic cracking units and sulfur recovery plants. The December 2015 action also finalized technical corrections and clarifications to Refinery NSPS subparts J and Ja to address issues raised by the American Petroleum Institute (API) in their 2008 and 2012 petitions for reconsideration of the final NSPS Ja rule that had not been previously addressed. These include corrections and clarifications to provisions for sulfur recovery plants, performance testing, and control device operating parameters.

In the process of implementing these new requirements, numerous questions and issues have been identified and we are proposing clarifications or technical amendments to address these questions and issues. These issues were raised in petitions for reconsideration and in separately issued letters from industry and in meetings with industry groups.

The EPA received three separate petitions for reconsideration. Two petitions were jointly filed by the API and American Fuel and Petrochemical Manufacturers (AFPM). The first of these petitions was filed on January 19, 2016, and requested an administrative reconsideration under section 307(d)(7)(B) of the Clean Air Act (CAA) of certain provisions of Refinery MACT 1 and 2, as promulgated in the December 2015 final rule. Specifically, API and AFPM requested that the EPA reconsider the maintenance vent provisions in Refinery MACT 1 for sources constructed on or before June 30, 2014; the alternate startup, shutdown, or hot standby standards for fluid catalytic cracking units (FCCUs) constructed on or before June 30, 2014, in Refinery MACT 2; the alternate startup and shutdown for sulfur recovery units constructed on or before June 30, 2014, in Refinery MACT 2; and the new catalytic reforming units (CRUs) purging limitations in Refinery MACT 2. The request pertained to providing and/or clarifying the compliance time for these sources. Based on this request and additional information received, the EPA issued a proposal on February 9, 2016 (81 FR 6814), and a final rule on July 13, 2016 (81 FR 45232), fully responding to the January 19, 2016, petition for reconsideration. The second petition from API and AFPM was filed on February 1, 2016, and outlined a number of specific issues related to the work practice standards for PRDs and flares, and the alternative water overflow provisions for DCUs, as well as a number of other specific issues on other aspects of the rule. The third petition was filed on February 1, 2016, by Earthjustice on behalf of Air Alliance Houston, California Communities Against Toxics, the Clean Air Council, the Coalition for a Safe Environment, the Community In-Power and Development Association, the Del Amo Action Committee, the Environmental Integrity Project, the Louisiana Bucket Brigade, the Sierra Club, the Texas Environmental Justice Advocacy Services, and Utah Physicians for a Healthy Environment. The Earthjustice petition claimed that several aspects of the revisions to Refinery MACT 1 were not proposed, and, thus, the public was precluded from commenting on them during the public comment period, including: (1) Work practice standards for PRDs and flares; (2) alternative water overflow provisions for DCUs; (3) reduced monitoring provisions for fenceline monitoring; and (4) adjustments to the risk assessment to account for these new work practice standards. On June 16, 2016, the EPA sent letters to petitioners granting reconsideration on issues where petitioners claimed they had not been provided an opportunity to comment. These petitions and letters granting reconsideration are available for review in the rulemaking docket (see Docket Item Nos. EPA–HQ–OAR–2010–0682–0860, EPA–HQ–OAR–2010–0682–0891 and EPA–HQ–OAR–2010–0682–0892).

On October 18, 2016 (81 FR 71661), the EPA proposed for public comment the issues for which reconsideration was granted in the June 16, 2016, letters. The EPA identified five issues in the proposal: (1) The work practice standards for PRDs; (2) the work practice standards for emergency flaring events; (3) the assessment of risk as modified based on implementation of these PRD and emergency flaring work practice standards; (4) the alternative work practice (AWP) standards for DCUs employing the water overflow design; and (5) the provision allowing refineries to reduce the frequency of fenceline monitoring at sampling locations that consistently record benzene concentrations below 0.9 micrograms per cubic meter. In that notice, the EPA also proposed two minor clarifying amendments to correct a cross referencing error and to clarify that facilities complying with overlapping equipment leak provisions must still comply with the PRD work practice standards in the 2015 final rule.

The February 1, 2016, API and AFPM petition for reconsideration included a number of recommendations for technical amendments and clarifications that were not specifically addressed in the October 18, 2016, proposal.[1] In addition, API and AFPM asked for clarification on various requirements of the final amendments in a July 12, 2016, letter.[2] The EPA addressed many of the clarification requests from the July 2016 letter and the petition for reconsideration in a letter issued on April 7, 2017.[3] API and AFPM also raised additional issues associated with the implementation of the final rule amendments in a March 28, 2017, letter to the EPA [4] and provided a list of typographical errors in the rule in a January 27, 2017, meeting [5] with the EPA. On January 10, 2018, AFPM submitted a letter containing a comparison of the electronic CFR, CFR, the **Federal Register** documents, and the redline versions of the December 2015 and October 2016 amendments to the Refinery Sector Rule noting discrepancies providing suggestions as to how these discrepancies should be resolved.[6] These items are located in Docket ID No. EPA–HQ–OAR–2016–0682. This proposal addresses many of the issues and clarifications identified by API and AFPM in their February 2016 petition for reconsideration and their subsequent communications with the EPA.

[1] Supplemental Request for Administrative Reconsideration of Targeted Elements of EPA's Final Rule ''Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards; Final Rule,'' Howard Feldman, API, and David Friedman, AFPM. February 1, 2016. Docket Item No. EPA–HQ–OAR–2010–0682–0892.

[2] Letter from Matt Todd, API, and David Friedman, AFPM, to Penny Lassiter, EPA. July 12, 2016. Available in Docket ID No. EPA–HQ–OAR–2010–0682.

[3] Letter from Peter Tsirigotis, EPA, to Matt Todd, API, and David Friedman, AFPM. April 7, 2017. Available at: *https://www.epa.gov/stationary-sources-air-pollution/december-2015-refinery-sector-rule-response-letters-qa.*

[4] Letter from Matt Todd, API, and David Friedman, AFPM, to Penny Lassiter, EPA. March 28, 2017. Available in Docket ID No. EPA–HQ–OAR–2010–0682.

[5] Meeting minutes for January 27, 2017, EPA meeting with API. Available in Docket ID No. EPA–HQ–OAR–2010–0682.

[6] David Friedman, ''Comparison of Official CFR and e-CFR Postings Regarding MACT CC/UUU and NSPS Ja Postings.'' Message to Penny Lassiter and Brenda Shine. January 10, 2018. Email.

III. What actions are we proposing?

A. Clarifications and Technical Corrections to Refinery MACT 1

1. Definitions

We are proposing to clarify the Refinery MACT 1 rule requirements by revising several definitions and adding one definition.

a. Flare Purge Gas

In their March 28, 2017, letter seeking additional clarifications, API and AFPM noted that the definition of ''flare purge gas'' could be interpreted to preclude the flaring of purge gas that may be introduced for safety reasons other than to prevent oxygen infiltration, such as to prevent freezing at the flare tip.[7] They requested that the EPA revise the definition to include gas necessary for other safety reasons. In the definition of the term, ''flare purge gas,'' we included a reference to a primary reason flare purge gas is added at the flare tip, namely to prevent oxygen infiltration, but did not intend for refiners to interpret this as not allowing them to add flare purge gas for other safety reasons. To reflect our intent, we are proposing to revise the definition to clarify that flare purge gas may also include gas needed for other safety reasons.

b. Flare Supplemental Gas

In their February 1, 2016, petition for reconsideration, API and AFPM requested a change to the definition of ''flare supplemental gas'' on the basis that the definition's reference to ''all gas that improves the combustion in the flare combustion zone'' could be interpreted to include assist air and assist steam. API and AFPM noted, in contrast, that the way the term ''flare supplemental gas'' is used throughout the rule appears to only include gases that increase combustion efficiency by raising the heat content of the combustion zone. This is evidenced by the fact that the definition of flare vent gas specifically includes flare supplemental gas and specifically excludes total steam or assist air. Further, they claimed that the rule incorrectly assumes that supplemental gas is always natural gas, and uses the term ''natural gas'' in the equations, and, thus, limiting a refiner's ability to use fuel gas as supplemental gas.

We agree that, as written, the definition could be misinterpreted and we are proposing to revise the definition of ''flare supplemental gas'' at 40 CFR 63.641. We also agree that we did not intend to limit flare supplemental gas to only natural gas, so throughout the rule, we are proposing to replace all instances of the term ''supplemental natural gas'' with the defined term ''flare supplemental gas.'' The specific instances of these replacements are provided in Table 2 of this preamble (see section III.A.7).

[7] API and AFPM, March 28, 2017.

c. Pressure Relief Device and Relief Valve

In their February 1, 2016, petition for reconsideration, API and AFPM noted that Refinery MACT 1 interchangeably uses the term ''relief valve'' and the term ''pressure relief device,'' and instead should be using the term ''pressure relief device'' throughout because a relief valve is only one type of pressure relief device. They requested that a definition of pressure relief device be added to Refinery MACT 1 to clarify that it includes different types of relief devices, such as relief valves and rupture disks. We agree, and we are proposing a definition of pressure relief device, proposing to revise the definition of relief valve, and proposing to consistently use the term ''pressure relief device'' throughout the rule.

d. Reference Control Technology for Storage Vessels

In their February 1, 2016, petition for reconsideration, API and AFPM noted that the Refinery MACT 1 storage vessel provisions at 40 CFR 63.660 require Group 1 storage vessels with floating roofs to comply with all the requirements of 40 CFR part 63, subpart WW, including requirements for fitting controls. However, the Refinery MACT 1 definition of ''reference control technology for storage vessels'' at 40 CFR 63.641 omits reference to these fitting requirements. They requested that the EPA revise the definition in 40 CFR 63.641 of Refinery MACT 1 to be consistent with the Refinery MACT 1 requirements for storage vessels at 40 CFR 63.660. They also noted that the term, ''reference control technology for storage vessels,'' is never actually used in the Refinery MACT 1 storage vessel provisions at 40 CFR 63.660. We agree and are revising the definition of reference control technology for storage vessels to be consistent with the storage vessel rule requirements at 40 CFR 63.660. As it relates to storage vessels, the only use of the term, ''reference control technology,'' is in the Refinery MACT 1 provisions pertaining to emissions averaging in 40 CFR 63.652.

2. Miscellaneous Process Vent Provisions

Petitioners requested a number of amendments and clarifications to the requirements identifying and managing the subset of miscellaneous process vents that result from maintenance activities.

a. Notice of Compliance Status (NOCS) Report

In their March 28, 2017, letter, API and AFPM noted that the miscellaneous process vent provision at 40 CFR 63.643(c) does not require an owner or operator to designate a maintenance vent as a Group 1 or Group 2 miscellaneous process vent. However, they stated that the reporting requirements at 40 CFR 63.655(f)(1)(ii) are unclear as to whether a NOCS report is needed for maintenance vents. We did not intend for the maintenance vents to be included in the NOCS report since we do not require the owner or operator to designate a maintenance vent as a Group 1 or Group 2 miscellaneous process vent. The rule has separate requirements for characterizing, recording, and reporting maintenance vents in 40 CFR 63.655 (g)(13) and (h)(12); therefore, it is not necessary to identify each and every place where equipment may be opened for maintenance in a NOCS report. To clarify, we are proposing to add language to 40 CFR 63.643(c) to explicitly state that maintenance vents need not be identified in the NOCS report.

b. Availability of a Pure Hydrogen Supply for Compliance With Maintenance Vent Provisions

Under 40 CFR 63.643(c) an owner or operator may designate a process vent as a maintenance vent if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed, or placed into service. Facilities generally must comply with one of three conditions prior to venting maintenance vents to the atmosphere (40 CFR 63.643(c)(1)(i–iii)). However, 40 CFR 63.643(c)(1)(iv) of the rule currently provides some flexibility for maintenance vents associated with equipment containing pyrophoric catalyst (*e.g.,* hydrotreaters and hydrocrackers) at refineries that do not have a pure hydrogen supply. This is because catalytic reformer hydrogen (the other primary hydrogen source) contains appreciable concentrations of light hydrocarbons which limits the ability to reduce the lower explosive limit (LEL) to 10 percent or less. For these vents, the LEL of the vapor in the equipment must be less than 20 percent, except for one event per year not to exceed 35 percent.

API and AFPM requested that the EPA reconsider the standards in 40 CFR 63.643(c)(1)(iv) for equipment containing pyrophoric catalyst, *e.g.,* hydrotreaters or hydrocrackers; in particular, they requested the EPA to re-examine the phrase ''. . . at refineries with a pure hydrogen supply.'' Specifically, they pointed out that many facilities have a pure hydrogen supply that is not used at hydrotreaters or hydrocrackers for a variety of reasons, including the fact that these units may be far removed from the on-site pure hydrogen production unit and piping the pure hydrogen supply to the unit is expensive. In addition, a facility could have a pure hydrogen production unit that is idled or shut down because a catalytic reforming unit produces adequate hydrogen for the facility. Petitioners suggested that the alternative limit for equipment containing pyrophoric catalyst should be provided whenever an active supply of pure hydrogen is not available at the unit.

As pyrophoric units (*e.g.,* hydrocrackers and hydrotreaters) require hydrogen to operate, at the time we finalized the amendments, we expected that pyrophoric units at a refinery with pure hydrogen supply would each have a pure hydrogen supply. That is, we did not specifically consider that some pyrophoric units at the refinery would have a pure hydrogen supply and others would not. We established this requirement under the authority of CAA section 112 (c)(2) and (c)(3) to address emissions from maintenance events which had been exempted from the process vent standards as episodic and non-routine emission sources in order to ensure that the maximum achievable control technology (MACT) included standards that apply at all times. We based these work practices, including those applicable to units without a pure hydrogen supply, on practices generally employed by the best performers.

We reviewed the recent comments received and the additional information provided by API and AFPM.[8] The information confirmed that a single refinery may have many pyrophoric units, some that have a pure hydrogen supply and some that do not have a pure hydrogen supply. Thus, our assumption at the time we issued the final rule regarding which units would use a pure hydrogen supply is incorrect. Thus, we are proposing to revise the regulations such that units without a pure hydrogen supply, even though there may be a pure hydrogen supply somewhere else at the facility, could comply with the standard in 40 CFR 63.643(c)(1)(iv).

Specifically, we are proposing to amend 40 CFR 63.643(c)(1)(iv) to read (new text highlighted in bold): ''If the maintenance vent is associated with equipment containing pyrophoric catalyst (*e.g.,* hydrotreaters and hydrocrackers) and a pure hydrogen supply is not available at the equipment at the time of the startup, shutdown, maintenance, or inspection activity, the LEL of the vapor in the equipment must be less than 20 percent, except for one event per year not to exceed 35 percent.''

c. Control Requirements for Maintenance Vents

Paragraph 63.643(a) specifies that Group 1 miscellaneous process vents must be controlled by 98 percent or to 20 parts per million by volume or to a flare meeting the requirements in 40 CFR 63.670. This paragraph also states in the second sentence that requirements for maintenance vents are specified in 40 CFR 63.643(c), ''and the owner or operator is only required to comply with the requirements in § 63.643(c).'' Paragraphs (c)(1) through (3) then specify requirements for maintenance vents. Paragraph (c)(1) requires that equipment must be depressured to a control device, fuel gas system, or back to the process until one of the conditions in paragraph (c)(1)(i) through (iv) is met. In reviewing these rule requirements, the EPA noted that we did not specify that the control device in (c)(1) must also meet requirements in paragraph (a). The second sentence in 40 CFR 63.643(a) could be misinterpreted to mean that a facility complying with the maintenance vent provisions in 40 CFR 63.643(c) must only comply with the requirements in paragraph (c) and not the control requirements in paragraph (a) for the control device referenced by paragraph (c)(1). The second sentence was meant to clarify that there is no obligation for characterizing and reporting miscellaneous process vents as Group 1 and Group 2 if these are maintenance vents. However, we inadvertently did not specify control device requirements for the control referenced by paragraph (c)(1) in paragraph (c). In omitting these requirements, we did not intend that the control requirement for maintenance vents prior to atmospheric release would not be compliant with Group 1 controls as specified under 40 CFR 63.643(a). These control requirements

[8] Letter from Matt Todd, API, and David Friedman, AFPM, to Penny Lassiter, EPA. August 1, 2017. Available in Docket ID No. EPA–HQ–OAR–2010–0682.

are consistent with control requirements for other Group 1 miscellaneous process vents. In order to clarify our intent, we are proposing to amend 40 CFR 63.643(c)(1) to read: ''Prior to venting to the atmosphere, process liquids are removed from the equipment as much as practical and the equipment is depressured to a control device meeting requirements in paragraphs (a)(1) or (2) of this section, a fuel gas system, or back to the process until one of the following conditions, as applicable, is met.''

d. Additional Maintenance Vent Alternative for Equipment Blinding

We received several requests to address equipment blinding in the maintenance venting provisions of 40 CFR 63.643(c). Equipment blinding is conducted to isolate equipment for maintenance activities. During the installation of the blind flange, a flanged connection in the equipment piping must be opened, allowing vapors in the equipment to be released to the atmosphere. Additionally, while the piping is open, a small amount of purge gas is typically used to ensure air (oxygen) does not enter the process equipment. The introduction of purge gas also results in emissions.

In their February 1, 2016, petition for reconsideration, API and AFPM requested clarification that emissions that occur when ''opening a flange on a CRU reactor to install a blind'' are considered emissions from a maintenance vent rather than a CRU vent. Additionally, API provided separate submissions with example scenarios and emissions data for CRU vents to the EPA on September 11, 2017,[9] and January 16, 2018.[10] In the response to comment document supporting the December 2015 final rule (see Section 10.2 of Docket Item No. EPA–HQ–OAR–2010–0682–0802), we noted that only ''catalytic reformer regeneration vents'' are excluded from the definition of miscellaneous process vents (MPV) and thereby excluded from using the maintenance vent provisions. However, we also indicated that other CRU vents could meet the definition of a maintenance vent (*i.e.,* an MPV that is only used as a result of startup, shutdown, maintenance, or inspection of equipment), and that those vents could comply with the maintenance vent provisions in 40 CFR 63.643(c). Specifically, we noted that the entire CRU is shut down for semi-regenerative units and that the maintenance vent provisions may apply in this case. We are clarifying in this preamble that vents (separate from the depressurization and purge cycle vent(s) covered under Refinery MACT 2) associated with opening a flange to install a blind after complete CRU shutdown may comply with the maintenance vent provisions.

In their March 28, 2017, letter, API and AFPM raised additional concerns with the maintenance vent requirements and the need to address the installation of blinds to isolate equipment for certain maintenance activities. They claimed there may be situations where refiners may not be able to meet the requirements in 40 CFR 63.643(c)(1)(i) through (iv) for maintenance vents, but they must be able to conduct these activities. For example, they may not be able to achieve the 10-percent LEL criterion in 40 CFR 63.643(c)(1)(i) prior to atmospheric venting because a valve used to isolate the equipment will not seat fully so organic material may continually leak into the isolated equipment.

We agree that installing a blind to prepare equipment for maintenance may be necessary and may not currently meet the conditions specified in 40 CFR 63.643(c)(1). To limit the emissions during the blind installation, we are proposing an additional condition addressed by the maintenance vent provisions as 40 CFR 63.643(c)(1)(v). We are proposing to require depressuring the equipment to 2 pounds (lb) per square inch gauge (psig) or less prior to equipment opening and maintaining pressure of the equipment where purge gas enters the equipment at or below 2 psig during the blind flange installation. The low allowable pressure limit will reduce the amount of process gas that will be released during the initial equipment opening and ongoing 2-psig pressure requirement will limit the rate of purge gas use. Together, these requirements will limit the emissions during blind flange installation and will result in comparable emissions allowed under the existing maintenance vent provisions. While we acknowledge that there may be circumstances where equipment blinding prior to achieving the 10-percent LEL criterion may be necessary, we expect these situations to be rare and that the owner or operator would remedy the situation as soon as practical (*e.g.,* replace the isolation valve or valve seat during the next turnaround in the example provided above). Therefore, at 40 CFR 63.643(c)(1)(v), we are proposing that this alternative maintenance vent limit be used under those situations where the primary limits are not achievable and blinding of the equipment is necessary. We are proposing to require refinery owners or operators to document each circumstance under which this provision is used, providing an explanation why the other criteria could not be met prior to equipment blinding and an estimate of the emissions that occurred during the equipment blinding process.

e. Recordkeeping for Maintenance Vents on Equipment Containing Less Than 72 Pounds (lbs) of Volatile Organic Compounds (VOC)

Under 40 CFR 63.643(c) an owner or operator may designate a process vent as a maintenance vent if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed, or placed into service. The rule specifies that prior to venting a maintenance vent to the atmosphere, process liquids must be removed from the equipment as much as practical and the equipment must be depressured to a control device, fuel gas system, or back to the process until one of several conditions, as applicable, is met (40 CFR 63.643(c)(1)). One condition specifies that equipment containing less than 72 lbs/day of volatile organic compounds (VOC) can be depressured directly to the atmosphere provided that the mass of VOC in the equipment is determined and provided that refiners keep records of the process units or equipment associated with the maintenance vent, the date of each maintenance vent opening, and records used to estimate the total quantity of VOC in the equipment at the time of vent opening. Therefore, each maintenance vent opening would be documented on an event-basis.

Industry petitioners noted that there are numerous routine maintenance activities, such as replacing sampling line tubing or replacing a pressure gauge, that involve potential release of very small amounts of VOC, often less than 1 lb per day, that are well below the 72 lbs/day of VOC threshold provided in 40 CFR 63.643(c)(1)(iii). They claimed that documenting each individual event is burdensome and unnecessary. We agree that documentation of each release from maintenance vents which serve equipment containing less than 72 lbs of VOC is not necessary, as long as there is a demonstration that the event is compliant with the requirement that the equipment contains less than 72 lbs of VOC. We are, therefore, proposing to revise these provisions to require a record demonstrating that the total

[9] Matt Todd, ''Examples.'' Message to Brenda Shine. September 11, 2017. Email.

[10] Karin C. Ritter, ''API Submitting: Flare Flow Meter Accuracy White Paper & CRU Data & Summary.'' Message to Penny Lassiter and Brenda Shine. January 16, 2018. Email.

quantity of VOC in the equipment based on the type, size, and contents is less than 72 lbs of VOC at the time of the maintenance vent opening. However, event-specific records are still required for each maintenance vent opening for which the deinventory procedures were not followed or for which the equipment opened exceeds the type and size limits established in the records for equipment containing less than 72 pounds of VOC.

f. Bypass Monitoring for Open-Ended Lines (OEL)

API and AFPM [11] requested clarification of the bypass monitoring provisions in 40 CFR 63.644(c) for open-ended lines (OEL). This provision exempts from bypass monitoring components subject to the Refinery MACT 1 equipment leak provisions in 40 CFR 63.648. Noting that the provisions in 40 CFR 63.648 only apply to components in organic hazardous air pollutant (HAP) service (*i.e.,* greater than 5-weight percent HAP), API and AFPM asked whether the EPA also intended to exempt open-ended valves or lines that are in VOC service (less than 5-weight percent HAP) and are capped and plugged in compliance with the standards in NSPS subpart VV or VVa or the Hazardous Organic NESHAP (HON; 40 CFR part 63, subpart H) that are substantively equivalent to the Refinery MACT 1 equipment leak provisions in 40 CFR 63.648. Petitioners noted that OELs in conveyances carrying a Group 1 miscellaneous process vent could be in less than 5-weight percent HAP service, but could still be capped and plugged in accordance with another rule, such as NSPS subpart VV or VVa or the HON. The EPA agrees that, because the use of a cap, blind flange, plug, or second valve for an open-ended valve or line is sufficient to prevent a bypass, the bypass monitoring requirements in 40 CFR 63.644(c) are redundant with NSPS subpart VV in these cases. We are proposing to amend 40 CFR 63.644(c) to make clear that open-ended valves or lines that are capped and plugged sufficiently to meet the standards in NSPS subpart VV at 40 CFR 60.482–6(a)(2), (b) and (c), are exempt from the bypass monitoring in 40 CFR 63.644(c).

3. Pressure Relief Device Provisions

In their February 1, 2016, petition, API and AFPM sought reconsideration of certain aspects of the requirements for PRDs in 40 CFR 63.648(j)(1) through (5). As finalized, 40 CFR 63.648(j)(1) provides operating requirements for PRDs in organic HAP gas or vapor service. Section 63.648(j)(2) specifies pressure release requirements for PRDs in organic HAP gas or vapor service. Section 63.648(j)(3) (discussed in greater detail below) specifies requirements for pressure release management for all PRDs in organic HAP service. Sections 63.648(j)(4) and (j)(5) provide exemptions from the requirements in (j)(1), (2), and (3) if all releases and potential leaks from a PRD are routed through a compliant control device or if the PRDs meet certain criteria.

As noted above, 40 CFR 63.648(j)(3) specifies requirements for pressure release management for all PRDs in organic HAP service, specifically: (j)(3)(i) provides requirements for monitoring affected PRDs; (j)(3)(ii) lists options for three redundant release prevention measures that must be applied to affected PRDs; (j)(3)(iii) requires root cause analysis and corrective action if an affected PRD releases to the atmosphere as a result of a pressure release event; (j)(3)(iv) stipulates how the facility must determine the number of release events during the calendar year for each affected PRD; and (j)(3)(v) specifies what release events are deemed a violation of the pressure release management work practice standards. Section 63.648(j)(5) identifies the types of PRDs exempted from pressure release management requirements in (j)(3).

a. Clarification of Requirements for PRD ''in organic HAP service''

Regarding the applicability of the PRD requirements in 40 CFR 63.648(j), API and AFPM requested that we clarify whether releases listed in paragraph 40 CFR 63.648(j)(3)(v) are limited to PRDs ''in organic HAP service.'' The heading for 40 CFR 63.648(j)(3)(v), *i.e.,* 40 CFR 63.648(j)(3) unambiguously states that the ''requirements specified in paragraphs (j)(3)(i) through (v) of this section'' apply to ''all pressure relief devices in organic HAP service'' and reflects the Agency's intent when promulgating these provisions. Subparagraphs (j)(3)(i) through (iv) use the phrase ''affected pressure relief device,'' and for consistency and clarity, we are proposing to add that phrase—''affected pressure relief device''— to paragraph (j)(3)(v) to clarify that the requirements in (j)(3)(v) also apply only to releases from PRDs that are in organic HAP service.

We also are proposing to amend the introductory text in paragraph (j). Currently, paragraph (j) states ''Except as specified in paragraphs (j)(4) and (5) of this section, the owner or operator must also comply with the requirements specified in paragraph (j)(3) of this section for all pressure relief devices.'' For consistency and clarity, we are proposing to add ''in organic HAP service'' to the end of this sentence to clearly indicate that the word ''all'' includes organic HAP liquid service PRDs.

b. Redundant Release Prevention Measures in 40 CFR 63.648(j)(3)(ii)

As stated earlier, section (j)(3)(ii) lists options for three redundant release prevention measures that must be applied to affected PRDs. The prevention measures in (j)(3)(ii) include: (A) Flow, temperature, level, and pressure indicators with deadman switches, monitors, or automatic actuators; (B) documented routine inspection and maintenance programs and/or operator training (maintenance programs and operator training may count as only one redundant prevention measure); (C) inherently safer designs or safety instrumentation systems; (D) deluge systems; and (E) staged relief system where initial pressure relief valve (with lower set release pressure) discharges to a flare or other closed vent system and control device.

The API and AFPM February 1, 2016, petition for reconsideration requested clarification as to whether two prevention measures can be selected from the list in 40 CFR 63.648(j)(3)(ii)(A). The rule does not state that the measures in paragraph (j)(3)(ii)(A) are to be considered a single prevention measure. These measures were grouped in subparagraph A because of similarities they have; however, they are separate measures. For example, a liquid level monitor discontinues the feed to the unit when the liquid level exceeds a set point and an overhead pressure monitor discontinues the feed to the unit if the pressure exceeds a certain level. If these measures operate independently, the EPA considers them two separate redundant prevention measures—that is, if the pressure exceeds a certain set point, then the feed to the unit is discontinued regardless of the liquid level and vice a versa. If both the pressure limit and the liquid level must be exceeded to trigger shutting off the feed to the unit, then that would be considered a single prevention measure. We also note that there may be occasions where the same type of monitor is used, but the parameter monitored is different. For example, a temperature monitor on the feed to a unit may be used to trigger feed shut-off to the unit, and a separate temperature monitor may be used for the vessel

[11] API and AFPM, February 1, 2016, and March 28, 2017.

overhead that also triggers feed shut-off to the unit. As the temperature monitors are not monitoring the same process stream and the actions of the monitors are independent, these systems would be considered two separate ''redundant prevention measures.'' To clarify this, we are proposing to revise 40 CFR 63.648(j)(3)(ii)(A) to make clear that independent, non-duplicative systems count as separate redundant prevention measures.

c. Pilot-Operated PRD and Balanced Bellows PRD

In a letter dated March 28, 2017, API and AFPM requested clarification on whether pilot-operated PRDs are required to comply with the pressure release management provisions of 40 CFR 63.648(j)(1) through (3).

A pilot-operated or balanced bellows PRD is often used to relieve back pressure so that the main PRD with which it is associated can be routed to a control device, back into the process or to the fuel gas system. Pilot-operated and balanced bellows PRDs are primarily used for pressure relief when the back pressure of the discharge vent may be high or variable. Conventional pressure relief devices act on a differential pressure between the process gas and the discharge vent. If the discharge vent pressure increases, the vessel pressure at which the PRD will open increases, potentially leading to vessel over-pressurization that could cause vessel failure. For systems that have high or variable back pressure, either balanced bellows or pilot-operated PRDs are used. Balanced bellows PRDs use a bellow to shield the pressure relief stem and top portion of the valve seat from the discharge vent pressure. A balanced bellows PRD will not discharge gas to the atmosphere during a release event, except for leaks through the bellows vent due to bellows failure or fatigue. Pilot-operated PRDs use a small pilot safety valve that discharges to the atmosphere to effect actuation of the main valve or piston, which then discharges to a control device. Balanced bellows or pilot operated PRDs are a reasonable and necessary means to safely control the primary PRD release.

Pilot-operated and balanced bellows PRDs are subject to the requirements at 40 CFR 63.648(j)(1) and (2) to ensure the PRDs do not leak and properly reseat following a release. However, based on our understanding of pilot-operated PRDs (see memorandum, ''Pilot-operated PRD,'' in Docket ID No. EPA–HQ–OAR–2010–0682) and balanced bellows PRDs, we are proposing that these PRDs are not subject to the requirements of 40 CFR 63.648(j)(3).

Section 63.648(j)(5) identifies the types of PRDs not subject to the pressure release management requirements in (j)(3). These include PRDs that do not have the potential to emit 72 lbs/day or more of VOC based on the valve diameter, the set release pressure, and the equipment contents (40 CFR 63.648(j)(5)(v)). In most cases, we expect that pilot-operated PRDs would release less than 72 lbs of VOC/day. However, this provision does not apply to all pilot vents because some have the potential to emit greater than 72 lbs/day of VOC. Even for releases greater than 72 lbs/day of VOC, we agree that the root cause analysis and corrective action is not necessary because the main release vent is not an atmospheric vent, but is instead routed to the flare header. Unless this event contributes to a flaring event resulting in visible emissions or velocity exceedance, the flare is operating as intended and controlling the PRD release. Although we expect pilot vent discharges will release less than 72 lbs/day of VOC, to ensure these vent discharges are indeed small, and to encourage low-emitting (*e.g.,* non-flowing) pilot-operated PRDs, we are proposing to amend the reporting requirements at 40 CFR 63.655(g)(10) and the recordkeeping requirements at 40 CFR 63.655(i)(11) to retain the requirements to report and keep records of each release to the atmosphere through the pilot vent that exceeds 72 lbs/day of VOC, including the duration of the pressure release through the pilot vent and the estimate of the mass quantity of each organic HAP release.

4. Delayed Coking Unit Decoking Operation Provisions

The provisions in 40 CFR 63.657(a) require owners or operators of DCU to depressure each coke drum to a closed blowdown system until the coke drum vessel pressure or temperature meets the applicable limits specified in the rule (2 psig or 220 degrees Fahrenheit for existing sources). Special provisions are provided in 40 CFR 63.657(e) and (f) for DCU using ''water overflow'' or ''double-quench'' method of cooling, respectively. According to 40 CFR 63.657(e), the owner or operator of a DCU using the ''water overflow'' method of coke cooling must hardpipe the overflow water (*i.e.,* via an overhead line) or otherwise prevent exposure of the overflow water to the atmosphere when transferring the overflow water to the overflow water storage tank whenever the coke drum vessel temperature exceeds 220 degrees Fahrenheit. The provision in 40 CFR 63.657(e) also provides that the overflow water storage tank may be an open or fixed-roof tank provided that a submerged fill pipe (pipe outlet below existing liquid level in the tank) is used to transfer overflow water to the tank.

In the October 18, 2016, reconsideration proposal, we opened the provisions in 40 CFR 63.657(e) for public comment, but we did not propose to amend the requirements. In response to the October 18, 2016, reconsideration proposal, we received several comments regarding the provisions in 40 CFR 63.657(e) for DCU using the water overflow method of coke cooling. API and AFPM wanted clarification that the water overflow requirements in 40 CFR 63.657(e) are only applicable if the primary pressure or temperature limits in 40 CFR 63.657(a) were not met prior to overflowing any water. We agree that an owner or operator of a DCU with a water overflow design does not need to comply with the provisions in 40 CFR 63.657(e) unless they cannot comply with the primary pressure or temperature limits in 40 CFR 63.657(a) prior to overflowing any water. However, if water overflow is used before the primary pressure or temperature limits in 40 CFR 63.657(a) are met, then the owner or operator must use ''controlled'' water overflow until the applicable temperature limit is achieved. This is required because the primary pressure limits are based on the vessel pressure, which is the pressure of the gas at the top of the coke drum, and once the water starts to overflow, we do not consider the pressure in the liquid filled overhead line to be representative of the DCU vessel pressure. We are proposing to clarify these points in 40 CFR 63.657(e).

In addition, environmental petitioners questioned whether the submerged fill requirement would effectively reduce emissions if gas is entrained into the overflow water leaving the coke drum such that the gas could then be emitted to the air out of the overflow water storage tank. We reviewed schematics of water overflow design DCU and found that a typical water overflow DCU uses a separator to prevent gas entrainment with the overflow water.[12] The overhead gas from the separator is routed to the DCU's closed blowdown system. The liquids accumulate at the bottom of the separator and are then routed to a storage vessel. We do not have information on the design of all

[12] Email correspondence from Dave Pavlich, Phillips 66, to Brenda Shine, EPA. March 6, 2017. Available in Docket ID No. EPA–HQ–OAR–2010–0682.

water overflow DCUs. If there are DCUs that do not use a separator, it is possible to entrain gases with the DCU water overflow and the submerged fill requirement would not effectively reduce emissions from the overflow water storage tank if gas is entrained in the water overflow. Therefore, we are also proposing to add provisions to 40 CFR 63.657(e) requiring the use of a separator or disengaging device operated in a manner to prevent entrainment of gases from the coke drum vessel to the overflow water storage tank. Gases from the separator must be routed to a closed vent blowdown system or otherwise controlled following the requirements for a Group 1 miscellaneous process vent. As separators appear to be an integral part of the water overflow system design, we are not projecting any capital investment or additional operating costs associated with this proposed amendment.

5. Fenceline Monitoring Provisions

We are proposing several amendments to the fenceline monitoring provisions in Refinery MACT 1. Many of the proposed revisions to the fenceline monitoring provisions are related to requirements for reporting monitoring data.

The December 1, 2015, final rule established provisions for monitoring fugitive emissions at refinery fencelines (40 CFR 63.658). Under the fenceline monitoring provisions, an owner/operator must monitor benzene concentrations around the perimeter (fenceline) of their facility using a network of passive air monitors that contain sorbent tubes (40 CFR 63.658(c)). Facilities are required to collect the tubes and analyze them for benzene every 2 weeks (40 CFR 63.658(e)), but may request an alternative test method for collecting and/or analyzing samples (40 CFR 63.658(k)). Facilities must then calculate the difference in the highest and lowest 2-week benzene concentrations reported at the facility fenceline, called the Δc (40 CFR 63.658(f)). If the annual rolling average Δc exceeds an action level of 9 micrograms per cubic meter ($\mu g/m^3$) benzene (40 CFR 63.658(f)(3)), the facility must conduct a root cause analysis and implement initial corrective action (40 CFR 63.658(g)). If the annual rolling Δc value for the next 2-week sampling period after the initial corrective action is greater than 9 $\mu g/m^3$, or if all corrective action measures identified require more than 45 days to implement, the owner or operator must develop a corrective action plan (40 CFR 63.658(h)).

The December 1, 2015, final rule included new EPA Methods 325A and B specifying monitor siting and quantitative sample analysis procedures. Method 325A requires an additional monitor be placed near known VOC emission sources if the VOC emissions source is located within 50 meters of the monitoring perimeter and the source is between two monitors. The December 1, 2015, final rule at 40 CFR 63.658(c)(1) provides ''known sources of VOCs . . . means a wastewater treatment unit, process unit, or any emission source requiring control according to the requirements of this subpart, including marine vessel loading operations.'' In their February 1, 2016, petition for reconsideration, API and AFPM recommended that the EPA exclude sources requiring control under the miscellaneous process vent requirements of 40 CFR 63.643 and the equipment leak requirements of 40 CFR 63.648 from the known sources of VOC specified in 40 CFR 63.658(c)(1) so that these emission sources would not trigger the need for additional fenceline monitors. In response, we are proposing an alternative to the additional monitor siting requirement for pumps, valves, connectors, sampling connections, and open-ended lines sources that are actively monitored monthly using audio, visual, or olfactory means and quarterly using Method 21 or the AWP. We believe this is reasonable because these sources may be insignificant and, under these circumstances, the timeframe for discovery of a leak (1 month to 3 months) and repair (within 15 days of discovery) is consistent with the timeframe needed to analyze a passive monitor sample (45 days) and complete the initial root cause analysis and corrective action (45 days after discovery). We consider this requirement to be an adequate alternative to the additional monitor requirement.

In their February 1, 2016, petition for reconsideration, API and AFPM suggested that if the Δc for the 2-week sampling period following an exceedance of the annual average Δc action level is 9 $\mu g/m^3$ or less, then appropriate corrective action measures may be assumed to already be implemented and the root cause analysis and corrective action analysis does not need to be performed. We are clarifying in this preamble that if a root cause analysis was performed and corrective action measures were implemented prior to the exceedance of the annual average Δc action level, then these documented actions can be used to fulfill the root cause analysis and corrective action requirements in 40 CFR 63.658(g) and recordkeeping in 40 CFR 63.655(i)(8)(viii).

In addition, we are proposing a revision to the reporting requirements for the fenceline data in 40 CFR 63.655(h)(8). Consistent with requests from API and AFPM in their February 1, 2016, petition for reconsideration, we are proposing that the quarterly reports are to cover calendar year quarters (*i.e.,* Quarter 1 is from January 1 through March 31; Quarter 2 is from April 1 through June 30; Quarter 3 is from July 1 through September 30; and Quarter 4 is from October 1 through December 31) rather than being directly tied to the date compliance monitoring began. This proposed change will simplify reporting by putting all refinery reports on the same schedule and reducing confusion regarding when refiners are required to report, especially if they own more than one facility.

We are also proposing several measures that would reduce burden and clarify reporting associated with collecting and analyzing quality assurance/quality control samples (field blanks and duplicates) associated with the fenceline monitoring requirements in 40 CFR 63.658(c)(3). First, we are proposing to require only one field blank per sampling period rather than two as currently required. Second, we are proposing to decrease the number of duplicate samples that must be collected each sample period. Instead of requiring a duplicate sample for every 10 monitoring locations, we propose that facilities with 19 or fewer monitoring locations only be required to collect one duplicate sample per sampling period and facilities with 20 or more sampling locations only be required to collect two duplicate samples per sampling period. These proposed changes reflect current practices and the needed quality assurance/quality control of blanks and samples. The reduced need for quality assurance/quality control samples is a result of enhancement and refinement of sample preparation and sorbent tube manufacturing, leading to an increase in precision of blanks and lower levels of containments in blanks as compared to the developmental stage of the method.

We received questions during the fenceline reporting webinars on how to report duplicate sample results and whether duplicate sample results are to be used in the calculation of Δc. Because there are two analytical results for each set of duplicate samples and the final rule was unclear on how to report these results, facilities were uncertain whether they should choose one of the two results for use in the calculation of

Δc or whether the results should be averaged. In order to clarify how the results of the duplicate sample analyses are to be used, we are proposing to require that duplicate samples be averaged together to determine the sampling location's benzene concentration for the purposes of calculating Δc.

Consistent with the requirements in 40 CFR 63.658(k) for requesting an alternative test method for collecting and/or analyzing samples, we are proposing to revise the Table 6 entry for 40 CFR 63.7(f) to indicate that 40 CFR 63.7(f) applies except that alternatives directly specified in 40 CFR part 63, subpart CC do not require additional notification to the Administrator or the approval of the Administrator. We also are proposing editorial revisions to the fenceline monitoring section; these proposed revisions are included in Table 2 in section III.A.7 of this preamble.

6. Flare Control Device Provisions

API and AFPM requested clarification in a December 1, 2016, letter to EPA [13] regarding assist steam line designs that entrain air into the lower or upper steam at the flare tip. The industry representatives noted that many of the steam-assisted flare lines have this type of air entrainment and likely were part of the dataset analyzed to develop the standards established in the 2015 final rule for steam-assisted flares. API and AFPM, therefore, maintain that these flares should not be considered to have assist air, and that they are appropriately and adequately regulated under the final standards for steam-assisted flares. Because flares with assist air are required to comply with both a combustion zone net heating value (NHV_{cz}) and a net heating value dilution parameter (NHV_{dil}), there is increased burden in having to comply with two operating parameters, and API and AFPM contend that this burden is unnecessary.

Assist air is defined to mean all air intentionally introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing, or inducing air into the flame. *Assist air* includes premix assist air and perimeter assist air. *Assist air* does not include the surrounding ambient air. Air entrainment through steam nozzles is intentionally introduced prior to or at the flare tip and, therefore, it is considered assist air. However, if this is the only assist air introduced prior to or at the flare tip, it is reasonable in most cases for the owner or operator to only need to comply with the NHV_{cz} operating limit. This is because an exceedance of the NHV_{cz} operating limit would also cause an exceedance of the NHV_{dil} operating limit in many cases.

We calculated the amount of air that must be entrained in the steam to cause a flare meeting the NHV_{cz} operating limit of 270 British thermal units per standard cubic foot (Btu/scf) to be below the NHV_{dil} operating limit of 22 Btu per square foot (Btu/ft^2). The NHV_{dil} parameter is a function of flare tip diameter. For flare tips with an effective tip diameter of 9 inches or more, there are no flare tip steam induction designs that can entrain enough assist air to cause a flare operator to have a deviation of the NHV_{dil} operating limit without first deviating from the NHV_{cz} operating limit. Therefore, we are proposing to allow owners or operators of flares whose only assist air is from perimeter assist air entrained in lower and upper steam at the flare tip and with a flare tip diameter of 9 inches or greater to comply only with the NHV_{cz} operating limit.

Steam-assisted flares with perimeter assist air and an effective tip diameter of less than 9 inches would remain subject to the requirement to account for the amount of assist air intentionally entrained within the calculation of NHV_{dil}. We recognize that this assist air cannot be directly measured, but the quantity of air entrained is dependent on the assist steam rate and the design of the steam tube's air entrainment system. We are proposing to add provisions to specify that owners or operators of these smaller diameter steam-assisted flares use the steam flow rate and the maximum design air-to-steam ratio of the steam tube's air entrainment system for determining the flow rate of this assist air. Using the maximum design ratio will tend to over-estimate the assist air flow rate, which is conservative with respect to ensuring compliance with the NHV_{dil} operating limit.

In addition to these revisions, for air assisted flares, we also are providing clarification on determining air flow rates. While we specifically provided for the use of engineering calculations for determining the flow rate, we received questions in the February 1, 2016, petition as to whether or not this allowed the use of fan curves for determining air assist flow rates. In the December 2015 final rule in the introductory paragraph of 40 CFR 63.670(i), we stated that continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates. To further clarify this point, we are proposing to include specific provisions for continuously monitoring fan speed or power and using fan curves for determining assist air flow rates.

In response to the February 1, 2016, petition for reconsideration from API and AFPM, we are also proposing to clarify the requirements for conducting visible emissions monitoring. API and AFPM raised a concern that the current language in 40 CFR 63.670(h) is unclear and could be interpreted to require facilities to flare regulated materials in order to conduct the required visible emissions monitoring. We recognize that many flares are used only during startup, shutdown, or emergency events and we agree that it is not reasonable to require refiners to flare regulated materials intentionally in order to conduct a visible emissions compliance demonstration. We are proposing to clarify that the initial 2-hour visible emissions demonstration should be conducted the first time regulated materials are routed to the flare. We are also proposing to clarify 40 CFR 63.670(h)(1) to provide that the daily 5-minute observations must only be conducted on days the flare receives regulated material and that the additional visible emissions monitoring is specific to cases when visible emissions are observed while regulated material is routed to the flare.

API and AFPM requested in their February 1, 2016, petition for reconsideration that we specify the averaging period for establishing the limit for the smokeless capacity of the flare and that it be a 15-minute average consistent with other flow parameters and velocity requirements. Owners or operators would use the cumulative flow rate and/or flare tip velocity determined according to 40 CFR 63.670(k) for assessing exceedances of the smokeless capacity, and this flow rate is specifically determined on a 15-minute block average. Consistent with these requirements, we are proposing to clarify, at 40 CFR 63.670(o)(1)(iii)(B), that the owner or operator must establish the smokeless capacity of the flare in a 15-minute block average and at 40 CFR 63.670(o)(3)(i) that the exceedance of the smokeless capacity of the flare is based on a 15-minute block average. We are also correcting an error in the units for the cumulative volumetric flow used in the flare tip velocity equation in 40 CFR

[13] Letter from Matt Todd, API, and David Friedman, AFPM, to Penny Lassiter, EPA. December 1, 2016. Available in Docket ID No. EPA–HQ–OAR–2010–0682.

63.670(k)(3). We are revising the units to specify standard cubic feet rather than actual cubic feet consistent with the cumulative volumetric flow monitoring requirements in 40 CFR 63.670(i)(1) and as stated in our response to public comments (Docket Item No. EPA–HQ–OAR–2010–0682–0802) in the discussion under 3.3.5.–Velocity Limit and Calculation Method. These specific edits are included in the summary of editorial corrections provided in Table 2 of his preamble (see section III.A.7).

Industry stakeholders with input from vendors have also made submissions [14] [15] [16] expressing concerns over the ability to meet the flare vent gas flow rate minimum accuracy requirements in 40 CFR 60.107a(f)(1)(ii) and in Table 13 of 40 CFR part 63, subpart CC when vent streams have low molecular weight. These requirements specify an accuracy of ±20 percent of the flow rate at velocities ranging from 0.1 to 1 foot per second and an accuracy of ±5 percent of the flow rate for velocities greater than 1 foot per second. Stakeholders stated that the accuracy requirements could not be met for some historical flow events when molecular weight of the flare vent gas was low, including: plant power outages caused by weather, compressor surges due to lightning strikes, compressor shutdowns due to high vibration events, hydrogen plant startup and shutdown, CRU plant startups, flare header maintenance activities and routing of high hydrogen process streams to the flare during maintenance events and process upsets. The EPA recognizes that flares can receive a wide range of process streams over a wide range of flows. We are clarifying in this preamble that certification of compliance for these flare vent gas flow meter accuracy requirements can be made based on the typical range of flare gas compositions expected for a given flare.

7. Other Corrections

We received comments from API and AFPM in their February 1, 2016, petition for reconsideration regarding the incorporation of 40 CFR part 63, subpart WW storage vessel provisions and 40 CFR part 63, subpart SS closed vent systems and control device provisions into Refinery MACT 1 requirements for Group 1 storage vessels at 40 CFR 63.660. The pre-amended version of the Refinery MACT 1 rule specified (by cross reference at 40 CFR 63.646) that storage vessels containing liquids with a vapor pressure of 76.6 kilopascals (11.0 pounds per square inch (psi)) or greater must be vented to a closed vent system or to a control device consistent with the requirements in the HON. The petitioners pointed out that the EPA did not retain this provision at 40 CFR 63.660 in the December 2015 final rule. In reviewing the introductory text at 40 CFR 63.660, we agree that the language was inadvertently omitted. We did not intend to deviate from the longstanding requirement limiting the vapor pressure of material that can be stored in a floating roof tank. We are, therefore, proposing to revise the introductory text in 40 CFR 63.660 to clarify that owners or operators of affected Group 1 storage vessels storing liquids with a maximum true vapor pressure less than 76.6 kilopascals (11.0 psi) can comply with either the requirements in 40 CFR part 63, subpart WW or SS and that owners or operators storing liquids with a maximum true vapor pressure greater than or equal to 76.6 kilopascals (11.0 psi) must comply with the requirements in 40 CFR part 63, subpart SS.

We also received comments from API and AFPM in their February 1, 2016, petition for reconsideration regarding provisions in 40 CFR 63.660(b). Section 63.660(b)(1) allows Group 1 storage vessels to comply with alternatives to those specified in 40 CFR 63.1063(a)(2) of subpart WW. Section 63.660(b)(2) specifies additional controls for ladders having at least one slotted leg. The petitioners explained that 40 CFR 63.1063(a)(2)(ix) provides extended compliance time for these controls, but that it is unclear whether this additional compliance time extends to the use of the alternatives to comply with 40 CFR 63.660(b). We are proposing language to make clear that the additional compliance time applies to the implementation of controls in 40 CFR 63.660(b).

We received several questions from industry pertaining to the requirement in paragraphs 40 CFR 63.655(f) and 40 CFR 63.655(f)(6) to submit a NOCS report. The final rule allows sources that are newly subject to Refinery MACT 1 to submit the NOCS in a periodic report rather than in a separate notification submission (40 CFR 63.655(f)(6)). It is reasonable that any source with a compliance date on or after February 1, 2016, should be able to follow the same approach. We are proposing to amend paragraphs 40 CFR 63.655(f) and 40 CFR 63.655(f)(6) to expressly provide that sources having a compliance date on or after February 1, 2016, may submit the NOCS in the periodic report rather than as a separate submission.

We are also proposing to clarify at 40 CFR 63.660(e) that the initial inspection requirements that applied with initial filling of the storage vessels are not required again simply because the source transitions from the requirements in 40 CFR 63.646 to 40 CFR 63.660.

We also received comments from API and AFPM [17] that the deadlines in the December 2015 final rule for reporting results of performance tests are inconsistent. The electronic reporting requirements in 40 CFR 63.655(h)(9) provide that the results of performance tests must be reported within 60 days of completing the performance test, while the NOCS report in 40 CFR 63.655(f), which is required to contain the performance test results, is due 150 days from the compliance date in the rule. We note that while some performance tests may be required prior to the requirement to submit the NOCS report, others may be performed when no NOCS report is due. We are proposing revisions to 40 CFR 63.655(f)(1)(i)(B)(*3*) and (C)(*2*), (f)(1)(iii), (f)(2), and (f)(4) to clarify that when the results of performance tests [or performance evaluations] are to be reported in the NOCS, the results are due by the date the NOCS report is due (report is due 150 days from the compliance date) whether the results are reported using the Compliance and Emissions Data Reporting Interface (CEDRI) or in hard copy as part of the NOCS report. If the source submits the test results using CEDRI, we are also proposing to specify that the source need not resubmit those results in the NOCS, but may instead submit specified information identifying that a performance test [or performance evaluation] was conducted and the unit(s) and pollutant(s) that were tested. We are also proposing to add the phrase ''Unless otherwise specified by this subpart'' to 40 CFR 63.655(h)(9)(i) and (ii) to make clear that test results associated with a NOCS report are not due within 60 days of completing the performance test or performance evaluation. We are also amending several references in Table 6—General Provisions Applicability to Subpart CC that discuss reporting requirements for performance tests or performance evaluations. As the General Provisions sections currently only address submissions of written test reports, we are proposing to clarify these entries in Table 6 to recognize that performance

[14] Kris A. Battleson, ''Chevron-vendor information for call at 12 PDT, 3 EDT.'' Message to Gerri Garwood and Brenda Shine. August 29, 2017. Email.

[15] Kris A. Battleson, ''meter QA/QC.'' Message to Brenda Shine. September 19, 2017. Email.

[16] Karin C. Ritter, ''API Submitting: Flare Flow Meter Accuracy White Paper & CRU Data & Summary.'' Message to Penny Lassiter and Brenda Shine. January 16, 2018. Email.

[17] API and AFPM, March 28, 2017.

test results may be written or electronic. Specifically, we are proposing to make these clarifications in Table 6 entries for 40 CFR 63.6(f)(3), 63.6(h)(8), 63.7(a)(2), and 63.8(e).

We also received questions from API and AFPM [18] on other aspects of the electronic reporting requirements. Industry representatives requested that electronic reporting only be required if all the test methods used to determine the emissions are supported by the Electronic Reporting Tool (ERT) (*e.g.,* methods for velocity as well as pollutant concentration). We recognize that the ERT does not support all test methods and that there is little value in submitting a stack flow electronically and the pollutant concentration in written format or PDF. We are revising the ERT website to clarify that electronic reporting is not required where the ERT does not support the test method for the pollutant of interest.

We recognize that there are instances when two primary pollutants may be measured during a single performance test, one supported by the ERT and one not supported by the ERT. For petroleum refineries, this occurs if the owner or operator conducts a particulate matter (PM) performance test coincident with the hydrogen cyanide performance test. Since the PM test methods (Methods 5, 5B, and 5F) are supported by the ERT, we require that this performance test be submitted via the ERT. However, testing for hydrogen cyanide is not supported by the ERT. The owner or operator may meet the reporting requirement for the hydrogen cyanide test by either including the test report as an attachment to the ERT submission so that both results are submitted electronically or by submitting the test report in hard copy or other agreed upon format.

Industry representatives also recommended that the requirement to report electronically be suspended until a reliable system is in place. We note that the submission of ERT-formatted performance test and performance evaluation reports using CEDRI is fully operational, and there are no known or reported system issues. CEDRI accepts all ERT version 5 report submissions that are properly created using the ERT. If the ERT zip file being uploaded to CEDRI is not created from the ERT or does not meet the file format requirements established by the EPA, CEDRI will not accept the file upload and will provide the user instructions on how to resolve the error(s). In addition, the Central Data Exchange (CDX) Helpdesk staff are available during regular business hours to support industry users in completing their submissions electronically using CEDRI. Any user concerns that cannot be resolved by the CDX Helpdesk are escalated to either EPA staff or the application support contractors for resolution. To date, over 3,400 ERT files have been submitted to the EPA through CEDRI. There have been 43 calls to the Helpdesk for assistance. The CDX Helpdesk resolved 34 of these calls, and the EPA and their support contractors resolved the remaining nine. We encourage all users to continue to contact the CDX Helpdesk with any issues encountered during the submission process.

We have also identified two broad circumstances in which electronic reporting extensions may be provided. In both circumstances, the decision to accept a claim of needing additional time to report is within the discretion of the Administrator, and reporting should occur as soon as possible. In 40 CFR 63.655(h)(10)(i), we address the situation where an extension may be warranted due to outages of the EPA's CDX or CEDRI which preclude a user from accessing the system and submitting required reports. If either the CDX or CEDRI is unavailable at any time beginning 5 business days prior to the date that the submission is due, and the unavailability prevents a user from submitting a report by the required date, users may assert a claim of EPA system outage. We consider 5 business days prior to the reporting deadline to be an appropriate timeframe because, if the system is down prior to this time, users still have 1 week to complete reporting once the system is back online. However, if the CDX or CEDRI is down during the week a report is due, we realize that this could greatly impact the ability to submit a required report on time. We will notify users about known outages as far in advance as possible by CHIEF Listserv notice, posting on the CEDRI website, and posting on the CDX website so that users can plan accordingly and still meet reporting deadlines. However, if a planned or unplanned outage occurs and users believe that it will affect or it has affected their ability to comply with an electronic reporting requirement, we have provided a process to assert such a claim.

Consistent with 40 CFR 63.655(h)(10), a source may seek an extension of the time to comply with an electronic reporting requirement. We are proposing to revise this provision to address the situation where an extension may be warranted due to a *force majeure* event, which is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents them from complying with the requirement to submit a report electronically as required by this rule. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazards beyond the control of the facility. If such an event occurs or is still occurring or if there are still lingering effects of the event in the 5 business days prior to a submission deadline, we are proposing a process to assert a claim of *force majeure* as a basis for extending the reporting deadline to protect refiners from noncompliance in cases where they cannot successfully submit a report by the reporting deadline for reasons outside of their control.

We received questions from API and AFPM [19] regarding the integrity checks required for the temperature and pressure monitor inspections in Table 13 (40 CFR part 63, subpart CC) and in Items 2, 4, 6, 7, 9, and 10 of Table 41 (40 CFR part 63, subpart UUU). Commenters noted that 40 CFR 63.657(b)(4), which applies to delayed coker pressure monitoring, indicates that the ''. . . pressure monitoring system must be visually inspected for integrity . . .'' and suggested that the table entries likewise specify that visual inspections are required/acceptable. The continuous parameter monitoring system (CPMS) pressure monitoring addressed in Tables 13 and 41 is broader than the monitoring requirement in 40 CFR 657(b)(4) and visual monitoring is not required for monitoring other systems as it is for delayed coker pressure monitoring. However, we agree that visual inspections are acceptable for those other systems, though, for those systems, there may be other methods of assessing integrity, such as current meters for wiring, that are not visual. In recognition of the fact that not all checks will be ''visual,'' we did not specify ''visual'' inspections in Tables 13 and 41.

In codifying the amendments to 40 CFR 63.655(i)(5), the specific recordkeeping requirements in the subparagraphs for regulation as it existed prior to the revisions were not retained in the regulations as published by the CFR. As reflected in the instructions to the amendments, we intended to move the heat exchanger recordkeeping requirements from paragraph (i)(4) to (i)(5) and to revise the introductory text to new paragraph (i)(5)

[18] API and AFPM, March 28, 2017.

[19] API and AFPM, March 28, 2017.

(see instructions 27.j. and 27.l. in 80 FR 75247). These revisions were incorporated into the CFR; however, the subparagraphs, which were not being revised, were not included in the CFR. We are proposing to revise 40 CFR 63.655(i)(5) to include the subparagraphs (as previously codified in subparagraph (i)(4)) that were inadvertently not included in the published CFR.

Similarly, the amendments to 40 CFR 63.655(h)(5)(iii) included in the December 2015 final rule **Federal Register** document (80 FR 75247) were not included in the regulations as published by the CFR. As reflected in the instructions to the amendments, we intended for the option to use an automated data compression recording system to be an approved monitoring alternative. In reviewing this amendment, the EPA noted that 40 CFR 63.655(h)(5) specifically addresses mechanisms for owners or operators to request approval for alternatives to the continuous operating parameter monitoring and recordkeeping provisions, while the provisions in 40 CFR 63.655(i)(3) specifically include options already approved for CPMS. Consistent with our intent for the use of an automated data compression recording system to be an approved monitoring alternative, we are proposing to move the paragraphs at 40 CFR 63.655(h)(5)(iii) to 40 CFR 63.655(i)(3)(ii)(C).

There are several additional revisions that we are proposing to Refinery MACT 1 to correct typographical errors, grammatical errors, and cross-reference errors. Table 2 of this preamble summarizes these editorial changes as well as other changes as discussed in this preamble.

TABLE 2—SUMMARY OF PROPOSED EDITORIAL AND OTHER CORRECTIONS TO REFINERY MACT 1

Provision	Proposed revision
MPV:	
Last sentence in § 63.643(c)	Replace "owner of operator" with "owner or operator."
§ 63.643(c)(1)(ii)	Define the term "psig" as pounds per square inch gauge and remove the last occurrence of "equipment."
§ 63.643(c)(1)(iii)	Define the term "VOC" as total volatile organic compounds.
PRD:	
§ 63.648(a)	Correct reference to "paragraphs (a)(1) through (2)" to "paragraphs (a)(1) through (3)." Also, correct reference to "paragraphs (c) through (i)" to "paragraphs (c) through (j)."
§ 63.648(c)	Correct reference to "paragraphs . . . (e) through (i) . . . " to "paragraphs . . . (e) through (j) . . ."
Last sentence in § 63.648(j)(3)(iv)	Add space between *majeure* and events.
DCU:	
§ 63.655(i)(7)(iii)(B)	Adjust recordkeeping requirement to the 5-minute period prior to pre-vent draining, rather than 15-minute period.
§ 63.657(a)(1)(i) and (ii); § 63.657(a)(2)(i) and (ii).	Correct the temperature and pressure limits to be expressed as maximums by adding "or less" to each numerical limit.
§ 63.657(b)(5)	Clarify that the output of the pressure monitoring system must be reviewed only when the drum is in service, so the provision reads, "The output of the pressure monitoring system must be reviewed each day the unit is operated to ensure . . ."
Fenceline:	
Second sentence in § 63.658(c)(2) and § 63.658(e).	Replace "owner of operator" with "owner or operator."
§ 63.658(d)(1)	Correct the reference to "paragraph (i)(1)" to "paragraph (i)(2)."
§ 63.658(d)(2)	Update the reference to Section 8.3 of Method 325A to more specifically reference Sections 8.3.1 through 8.3.3 of Method 325A.
§ 63.658(e)(3)(iv)	Delete the word "an" in the first sentence.
Flares:	
§ 63.670(o)	Correct the reference to "paragraphs (o)(1) through (8)" to "paragraphs (o)(1) through (7)."
§ 63.670(j)(6)	Correct the reference to subparagraphs "(j)(6)(i) through (v)" to "(j)(6)(i) through (iii)."
§ 63.670(k)(3) equation term for Q_{cum}.	Correct units for Q_{cum} to be "standard cubic feet."
§§§ 63.670(i), (m)(2) including equation terms, and (n)(2) including equation terms.	Update the reference to "supplemental natural gas" to the defined term "flare supplemental gas."
§ 63.670(o)(1)(ii)(B)	Correct the reference to paragraph "§ 63.648(j)(5)" to "§ 63.648(j)(3)(ii)(A) through (E)." [20]
§§ 63.670(o)(1)(iii)(B) and (o)(3)(i)	Edit the paragraphs to refer to a 15-minute block averaging time relative to the smokeless design capacity of the flare.
Table 13, Hydrogen Analyzer Requirements for Sampling Location.	Add "Where feasible" to the description of sampling location for the hydrogen analyzer.
Storage Vessels:	
§ 63.655(f)(1)(i)(A)(*1*) through (*3*)	Add a reference to the option to comply with § 63.660 in addition to compliance with § 63.646.
§ 63.655(g)(2)(B)(*1*)	Add the word "area" to the end of the sentence consistent with the same requirement in the HON.
§ 63.655(h)(2)(ii)	Correct the reference to "§ 63.1063(d)(3)" to "§ 63.1062(d)(3)."
§ 63.660(b)(1)	Correct the reference to "§ 63.1063(a)(2)(vii)" to "§ 63.1063(a)(2)(viii)."
§ 63.660(i)(2)	Delete the second use of the word "to."
Other:	
Table 6, Comment for Reference § 63.7(h)(3).	Correct the reference "§ 63.7(g)(3)" to "§ 63.7(h)(3)(i)."

B. Clarifications and Technical Corrections to Refinery MACT 2

1. FCCU Provisions

In order to demonstrate compliance with the alternative PM standard for FCCU at 40 CFR 63.1564(a)(5)(ii), the outlet (exhaust) gas flow rate of the catalyst regenerator must be determined. Refinery MACT 2 provides that owners or operators may determine this flow rate using a flow CPMS or the alternative provided in 40 CFR 63.1573(a). Currently, the language in 40 CFR 63.1573(a) restricts the use of the alternative to occasions when ''the unit does not introduce any other gas streams into the catalyst regenerator vent.'' API and AFPM [21] claim that while this restriction is appropriate for determining the flow rate for applying emissions limitations downstream of the regenerator because additional gases introduced to the vent would not be measured using this method, it is not a necessary constraint for determining compliance with the alternative PM limit. This is because the alternative PM standard applies at the outlet of the regenerator prior to the primary cyclone inlet and this is the flow measured by the alternative in 40 CFR 63.1573(a). We agree that there should be no such restriction when determining the outlet flow rate to the regenerator for the purposes of demonstrating compliance with the alternate PM standard at 40 CFR 63.1564(a)(5)(ii), and are proposing to amend 40 CFR 63.1573(a) to remove that restriction.

Additionally, API and AFPM noted in their February 1, 2016, petition for reconsideration that the FCCU alternative organic HAP standard for startup, shutdown, and hot standby in 40 CFR 63.1565(a)(5)(ii) requires maintaining the oxygen concentration in the regenerator exhaust gas at or above 1 vol. percent (dry) (*i.e.,* greater than or equal to 1-percent oxygen (O_2) measured on a dry basis); however, they claim process O_2 analyzers measure O_2 on a wet basis. Therefore, the commenters explained that they would need to take a moisture measurement and use the measurement to correct the measured O_2 in order to demonstrate compliance with the standard. Industry commenters explained that this is unnecessary as an FCCU meeting the 1-percent O_2 alternative standard measured on a wet basis will be compliant with the 1-percent limit on a dry basis. We agree that meeting the 1-percent O_2 standard on a wet basis measurement will always mean that there is more O_2 than if the concentration value is corrected to a dry basis. As such, a wet basis measurement of 1-percent O_2 is adequate to demonstrate compliance with the minimum O_2 alternative limit in 40 CFR 63.1565(a)(5)(ii). Therefore, we are proposing to amend 40 CFR 63.1565(a)(5)(ii) and Table 10 to allow for the use of a wet O_2 measurement for demonstrating compliance with the standard so long as it is used directly with no correction for moisture content.

2. Other Corrections

API and AFPM commented in their February 1, 2016, petition for reconsideration that the amendments to the provision for CPMS monitoring and data collection in Refinery MACT 2 at 40 CFR 63.1572(d)(1) which do not exclude periods of monitoring system malfunction, associated repairs, and quality assurance or control activities is inconsistent with paragraph (d)(2) which specifies that data recorded during required quality assurance or control activities may not be used. Additionally, API and AFPM stated that an analogous provision in 40 CFR 63.1572(d) for CPMS monitoring and data collection was maintained in the final Refinery MACT 1 at 40 CFR 63.671(a)(4). We agree that we should maintain consistency between Refinery MACT 1 and Refinery MACT 2 whenever possible and, in this case, there is no good reason for the two subparts to differ. CPMS readings taken during periods of monitoring system malfunctions and repairs do not provide accurate or valid data. In order to repair a monitoring system, the CPMS must generally be taken offline or completely out of service, and, therefore, there would be no data to record. During a monitoring system malfunction, while there may or may not be data to record, the malfunction will affect the accuracy of the data. This is the reason why these data are generally excluded from data averages (as noted in 40 CFR 63.8(g)(5)). Therefore, we are proposing to amend the language in Refinery MACT 2 at 40 CFR 63.1572(d)(1) so that the language is the same as that in Refinery MACT 1 at 40 CFR 63.671(a)(4).

The final amendments provide alternative emission limits during periods of startup and shutdown for some units, such as the FCCU alternative organic HAP standard for startup, shutdown, and hot standby in 40 CFR 63.1565(a)(5)(ii). API and AFPM questioned in their February 1, 2016, petition for reconsideration whether the recordkeeping requirements in 40 CFR 63.1576(a)(2)(i) apply when the owners or operators elect to comply with the otherwise applicable emissions limitations during periods of startup and shutdown. Separate recordkeeping requirements apply when a source is subject to the otherwise applicable emissions limits; thus, it is not necessary for the recordkeeping requirements in 40 CFR 63.1576(a)(2)(i) to also apply. Therefore, we are proposing to amend the recordkeeping requirement in 40 CFR 63.1576(a)(2)(i) to apply only when facilities elect to comply with the alternative startup and shutdown standards provided in 40 CFR 63.1564(a)(5)(ii) or 40 CFR 63.1565(a)(5)(ii) or 40 CFR 63.1568(a)(4)(ii) or (iii).

We are proposing to revise Refinery MACT 2 to address the same issue raised for Refinery MACT 1 regarding the reporting of initial performance tests. We are proposing to amend 40 CFR 63.1574(a)(3) to clarify that the results of performance tests conducted to demonstrate initial compliance are to be reported by the date the NOCS report is due (150 days from the compliance date) whether the results are reported using CEDRI or in hard copy as part of the NOCS report and to clarify the information to be included in the NOCS if the test results are submitted through CEDRI. Unlike Refinery MACT 1, Refinery MACT 2 has on-going performance test requirements. We are proposing that the results of periodic performance tests and the one-time hydrogen cyanide (HCN) test required by 40 CFR 63.1571(a)(5) and (6) must be reported with the semi-annual compliance reports as specified in 40 CFR 63.1575(f) instead of within 60 days of completing the performance evaluation. Similarly, we are also proposing to streamline reporting of the results of performance evaluations for continuous monitoring systems (as provided in entry 2 to Table 43) to align with the semi-annual compliance reports as specified in 40 CFR 63.1575(f), rather than requiring a separate report submittal. We are proposing to add the phrase ''Unless otherwise specified by this subpart'' to 40 CFR 63.1575(k)(1) and (2) to indicate that any performance tests or performance evaluations required to be reported in a NOCS report or a semi-annual compliance report are not subject to the 60-day deadline specified in these paragraphs. We are also proposing to add 40 CFR 63.1575(l) to

[20] A similar revision was included in the October 18, 2016, reconsideration notice and proposed rule (81 FR 71661). In the reconsideration notice and proposed rule, we proposed to correct the reference to paragraph ''§ 63.648(j)(5)'' to ''§ 63.648(j)(3)(ii).'' In this proposal, we are including a more specific reference to the subparagraphs in 40 CFR 63.648(j)(3) to clarify that the rule requires owners and operators to evaluate the list of prevention measures in these subparagraphs.

[21] API and AFPM, March 28, 2017.

address extensions to electronic reporting deadlines.

Similar to the revisions in Table 6 to 40 CFR part 63, subpart CC (see section III. A.7), we are proposing to revise selected entries in Table 44 to Subpart UUU of Part 63—Applicability of NESHAP General Provisions to Subpart UUU, to clarify several sections of the General Provisions (40 CFR part 63, subpart A) that the reporting can be written or electronic, the timing of these reports is specified in 40 CFR part 63, subpart UUU, and the subpart UUU provisions supersede the General Provisions. Specifically, we are proposing to revise Table 44 entries for 40 CFR 63.6(f)(3), 63.7(h)(7)(i), 63.6(h)(8), 63.7(a)(2), 63.7(g), 63.8(e), 63.10(d)(2), 63.10(e)(1), 63.10(e)(2), and 63.10(e)(4) to explain that 40 CFR part 63, subpart UUU specifies how and when to report the results of performance tests or performance evaluations.

There are several additional revisions that we are proposing to Refinery MACT 2 to correct typographical errors, grammatical errors, and cross-reference errors. These editorial corrections are summarized in Table 3 of this preamble.

TABLE 3—SUMMARY OF PROPOSED EDITORIAL AND MINOR CORRECTIONS TO REFINERY MACT 2

Provision	Proposed revision
§ 63.1564(b)(4)(iii)	Correct the reference to “paragraph (a)(1)(iii)” to “paragraph (a)(1)(v).”
§ 63.1564(c)(3)	Correct the reference to “paragraph (a)(1)(iii)” to “paragraph (a)(1)(v).”
§ 63.1564(c)(4)	Correct the reference to “paragraph (a)(1)(iv)” to “paragraph (a)(1)(vi).”
§ 63.1564(c)(5)(iii)	Correct the units of measure for velocity to ft/sec.
§ 63.1569(c)(2)	Correct the reference to “paragraph (a)(2)” to “paragraph (a)(3).”
§ 63.1571(a)(5) and (6); and Table 6, Item 1.ii.	Add “or within 60 days of startup of a new unit” to the compliance time for the periodic performance testing requirement for PM or Ni and to the one-time performance testing requirement for HCN.
§ 63.1571(d)(1)	Correct the reference to “paragraph (a)(1)(iii)” to “paragraph (a)(1)(v).”
§ 63.1571(d)(2)	Correct the reference to “paragraph (a)(1)(iv)” to “paragraph (a)(1)(vi).”
§ 63.1572(c)(1)	Delete duplicative sentence, “You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in Table 41 of this subpart.”
Table 3	Correct the spelling of the word “continuous” in the table’s title.
Table 3, Item 2.c	Delete the words, “the coke burn-off rate or.” Correct the footnote reference from “3” to “1.”
Table 3, Items 6 through 9	Correct the reference to “§ 60.120a(b)(1)” to “§ 60.102a(b)(1).”
Table 4, Item 9.c	Correct the reference to “Equation 2 of § 63.571” to “Equation 1 of § 63.571, if applicable.”
Table 4, Item 10.c	Correct the reference to “item 6.c.” to “item 9.c.” and add “if applicable” after reference to Equation 2 of § 63.571.
Table 5, Item 3	Correct the reference to “60.102a(b)(1)(i)” to “60.102a(b)(1)(ii),” and correct the reference to “1.0 g/kg (1.0 lb/1,000 lb)” to “0.5 g/kg (0.5 lb PM/1,000 lb).”
Table 6, Item 7	Delete ” and 30% opacity” as this is not part of Option 1b.
Table 43, Item 2	Correct the compliance date to the effective date of the rule (February 1, 2016).

C. Clarifications and Technical Corrections to NSPS Ja

During recent implementation efforts, it was brought to our attention that the testing requirement in 40 CFR 60.105a(b)(2)(ii) differs from similar requirements in 40 CFR 60.105a(d)(4), (f)(4), and (g)(4) where we allow use of Method 3, 3A, or 3B, both for the performance tests and the relative accuracy tests. The language in 40 CFR 60.105a(b)(2)(ii) does not currently include Methods 3A and 3B (and the alternative ANSI/ASME method for EPA Method 3B) and mistakenly cites Appendix A–3 rather than Appendix A–2. We are proposing to revise 40 CFR 60.105a(b)(2)(ii), consistent with the other similar requirements in NSPS subpart Ja listed above, to read as follows, ‘‘The owner or operator shall conduct performance evaluations of each CO_2 and O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Method 3, 3A or 3B of appendix A–2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ‘‘Flue and Exhaust Gas Analyses,’’ (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.’’ The EPA is proposing a corresponding change to 40 CFR 60.17(g)(14) to add 40 CFR 60.105a(b) to the list of regulations in which this method has been incorporated by reference. It should be noted that through this revision, the EPA is proposing to include in a final EPA rule regulatory text that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5(a), the EPA is proposing to incorporate by reference the ANSI/ASME PTC 19.10–1981 test method. The EPA has made, and will continue to make, this document generally available electronically through *www.regulations.gov* and/or in hard copy at the appropriate EPA office (see the **ADDRESSES** section of this preamble for more information).

We also identified that the second sentence of 40 CFR 60.106a(a)(1)(iii) includes the following clause, ‘‘. . . and Method 3 or 3A of appendix A–2 of part 60 for conducting the relative accuracy evaluations’’ which is redundant to 40 CFR 60.106a(a)(1)(vi) (and again, does not include all three Methods). We are proposing to delete this clause. We are also proposing to change the word ‘‘Methods’’ to ‘‘Method’’ in the second sentence of 40 CFR 60.106a(a)(1)(iii) to better reflect our intent for facilities to select a single performance evaluation method.

IV. Summary of Cost, Environmental, and Economic Impacts

This proposed rule is expected to result in overall cost and burden reductions. Specifically, the proposed amendments expected to reduce burden are: Revisions of the maintenance vent provisions related to the availability of a pure hydrogen supply for equipment containing pyrophoric catalyst, revisions of recordkeeping requirements for maintenance vents associated with equipment containing less than 72 lbs VOC, inclusion of specific provisions for pilot-operated and balanced bellows PRDs, and inclusion of specific provisions related to steam tube air entrainment for flares. These proposed amendments are described in detail in sections III.A.2.b, III.A.2.d, III.A.3.c, and III.A.5 of this preamble, respectively. The other proposed amendments will have an insignificant effect on the compliance costs associated with these standards. Additionally, none of the proposed amendments are projected to appreciably impact the emissions reductions associated with these standards.

Some of the cost reductions associated with this proposed rule were not fully captured in the impacts estimated for the December 2015 final rule. The total capital investment cost of the December 2015 final rule was estimated at $283 million, $112 million from the final amendments for storage vessels, DCUs, and fenceline monitoring, and $171 million from standards for flares and PRDs. The annualized costs of the final amendments for storage vessels, DCUs, and fenceline monitoring were estimated to be approximately $13.0 million and the annualized costs of the final standards for flares and PRDs were estimated to be approximately $50.2 million. There were no capital costs estimated for the maintenance vent provisions in the December 2015 final rule and only limited recordkeeping and reporting costs. Furthermore, while significant capital and operating costs were projected for flares, we may have underestimated the number of steam-assisted flares that would also have to demonstrate compliance with the NHV_{dil} operating limit.

As described previously in section III.A.2.b of this preamble, we did not specifically consider that some units with pyrophoric catalyst at the refinery would have a pure hydrogen supply and others would not. Therefore, we did not include costs in the December 2015 final rule impacts for refineries that have a pure hydrogen supply to add new piping (and possibly increase their hydrogen production capacity) to bring pure hydrogen to units with pyrophoric catalyst that were not currently piped to receive pure hydrogen. Based on information provided by industry petitioners, the capital investment cost to supply pure hydrogen to pyrophoric units that currently do not have a pure hydrogen supply (but that are located at refineries with a pure hydrogen supply) is estimated to be approximately $76 million. Using a capital recovery of 0.0944 based on 20-year equipment life and 7-percent interest, hydrogen supply upgrades would have increased the previously estimated annualized cost by $7,174,400 per year. Table 4 provides the cost reduction expected for the proposed amendments concerning hydrogen supply for pyrophoric units, as well as other proposed amendments.

TABLE 4—PROJECTED IMPACTS OF THE PROPOSED AMENDMENTS TO REFINERY MACT 1

	Current estimate of Dec 2015 rule capital investment costs, million $	Current estimate of Dec 2015 rule annualized costs, million $/yr	Estimated capital investment cost if proposed rule is implemented, million $	Estimated annualized cost if proposed rule is implemented, million $/yr	Reduction in annualized cost of refinery standards, million $/yr
Maintenance vents provisions for equipment with pyrophoric catalyst	76	7.17	0	0	7.17
MPV recordkeeping requirements	0	0.678	0	0.001	0.677
PRD requirements	11.1	3.33	10.0	3.00	0.33
Flare monitoring for steam-assisted flares with air entrainment	130	26.9	130	23.6	3.31

For the proposed amendments to the recordkeeping requirements for equipment containing less than 72 lbs of VOC, the impacts in the December 2015 final rule only included one-time planning costs for how to comply with the maintenance vent requirements; it was assumed that facilities would have maintenance records for each activity, so no additional recordkeeping burden was estimated. According to industry petitioners, there are numerous activities, such as replacing pressure transducers or tubing that would qualify under the less than 72 lbs of VOC provisions, but for which event-specific records are not traditionally maintained. Based on the per event recordkeeping requirement for maintenance vents using the 72 lbs VOC provision in the December 2015 rule, we now estimate that there would be 500 of these small maintenance vent openings per year per refinery and that 0.1 hour would be required to record each individual event, resulting in a nationwide burden of $678,625 per year. The revisions in the proposed rule, would only require records that should be part of the annual planning assessment and records for events not following the deinventory procedures included in these plans. We estimate that each facility would spend 0.1 hour for each non-conforming event and would only have one such event each year with an estimated nationwide burden of $1,357 per year. Thus, the proposed amendments are estimated to yield savings of approximately $677,268 per year considering the actual estimated annualized burden of the December 2015 final rule.

We estimated the PRD requirements in the December 2015 rule would result in a capital investment of $11.1 million to implement prevention measures and flow monitoring systems on PRDs. Combined with the recordkeeping and reporting requirements, the annualized cost of the PRD provisions in the December 2015 final rule was estimated to be $3.3 million per year. We estimate that approximately 10 percent of PRDs at refineries are either pilot-operated or balanced bellows. Thus, if there is a commensurate 10-percent decrease in these costs based on the proposed provisions for pilot-operated or balanced bellows PRD, we estimate the proposed amendments would yield a reduction in capital investment of $1.1 million and a reduction in annualized costs of $330,000 per year.

We estimated that the provisions for steam-assisted flares in the December 2015 rule would result in a capital investment of $130 million and annualized costs of $23.6 million. However, these costs did not include costs to also assess compliance with the NHV_{dil} operating limit for those steam-assisted flares that used intentional air entrainment within the steam tubes. There is no way to measure this air entrainment rate, but engineering calculations were allowed to be used. We estimated that there were 190 steam-assisted flares that received routine flow. We estimate that 0.5 additional hour would be required each day to assess compliance with the NHV_{dil} operating limits for these flares. If all 190 steam-assisted flares were designed for air entrainment in the steam tubes, this would suggest that the annualized cost of the December 2015 final rule for steam-assisted flares is closer to $26.9 million per year and that the proposed amendments allowing owners or operators of certain steam-assisted flares with air entrainment at the flare tip to comply only with the NHV_{cz} operating limits would reduce annualized costs by approximately $3.3 million.

A detailed memorandum documenting the estimated burden reduction has been included in the docket for this rulemaking (see memorandum titled, ''Impact Estimates for the 2017 Proposed Revisions to Refinery MACT 1,'' in Docket ID No. EPA–HQ–OAR–2010–0682).

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

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

This action is not a significant regulatory action and was, therefore, not submitted to OMB for review.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is expected to be an Executive Order 13771 deregulatory action. Details on the estimated cost savings of this proposed rule can be found in EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 1692.11. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

One of the proposed technical amendments included in this notice impacts the recordkeeping requirements in 40 CFR part 63, subpart CC for certain maintenance vents associated with equipment containing less than 72 lbs VOC as found at 40 CFR 63.655(i)(12)(iv). The new recordkeeping requirement specifies records used to estimate the total quantity of VOC in the equipment and the type and size limits of equipment that contain less than 72 lb of VOC at the time of the maintenance vent opening be maintained. As specified in 40 CFR 63.655(i)(12)(iv), additional records are required if the deinventory procedures were not followed for each maintenance vent opening or if the equipment opened exceeded the type and size limits (*i.e.,* 72 lbs VOC). These additional records include identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and records used to estimate the total quantity of VOC in the equipment at the time the maintenance vent was opened to the atmosphere. These records will assist the EPA with determining compliance with the standards set forth in 40 CFR 63.643(c)(iv).

Respondents/affected entities: Owners or operators of existing or new major source petroleum refineries that are major sources of HAP emissions. The NAICS code is 324110 for petroleum refineries.

Respondent's obligation to respond: All data in the ICR that are recorded are required by the proposed amendments to 40 CFR part 63, subpart CC—National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries.

Estimated number of respondents: 142.

Frequency of response: Once per year per respondent.

Total estimated burden: 16 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $1,640 (per year), includes $0 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than May 10, 2018.

The EPA will respond to any ICR-related comments in the final rule.

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 impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden, or otherwise has a positive economic effect on the small entities subject to the rule. The action consists of amendments, clarifications, and technical corrections which are expected to reduce regulatory burden. As described in section IV of this preamble, we expect burden reduction for: Revisions of the maintenance vent provisions related to the availability of a pure hydrogen supply for equipment containing pyrophoric catalyst, revisions of recordkeeping requirements for maintenance vents associated with equipment containing less than 72 lbs VOC, inclusion of specific provisions for pilot-operated and balanced bellows PRDs, and inclusion of specific provisions related to steam tube air entrainment for flares. Furthermore, as noted in section IV of this preamble, we do not expect the proposed amendments to change the expected economic impact analysis performed for the existing rule. We have, therefore, concluded that this action will relieve regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

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.

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

This action does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

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

This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. The proposed amendments serve to make technical clarifications and corrections. We expect the proposed revisions will have an insignificant effect on emission reductions. Therefore, the proposed amendments should not appreciably increase risk for any populations.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

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

This rulemaking involves technical standards. As described in section III.C of this preamble, the EPA proposes to use the voluntary consensus standard ANSI/ASME PTC 19–10–1981—Part 10 ''Flue and Exhaust Gas Analyses'' as an acceptable alternative to EPA Methods 3A and 3B for the manual procedures only and not the instrumental procedures. This method is available at the American National Standards Institute (ANSI), 1899 L Street NW, 11th floor, Washington, DC 20036 and the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990. See *https://wwww.ansi.org* and *https://www.asme.org*.

K. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). The proposed amendments serve to make technical clarifications and corrections. We expect the proposed revisions will have an insignificant effect on emission reductions. Therefore, the proposed amendments should not appreciably increase risk for any populations.

List of Subjects in 40 CFR Parts 60 and 63

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

Dated: March 20, 2018.

E. Scott Pruitt,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is proposed to be amended 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. Section 60.17 is amended by revising paragraph (g)(14) to read as follows:

§ 60.17 Incorporations by reference.

*   *   *   *   *

(g) * * *

(14) ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for §§ 60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i), and (j), 60.105a(b), (d), (f), and (g), § 60.106a(a), § 60.107a(a), (c), and (d), tables 1 and 3 to subpart EEEE, tables 2 and 4 to subpart FFFF, table 2 to subpart JJJJ, § 60.285a(f), §§ 60.4415(a), 60.2145(s) and (t), 60.2710(s), (t), and (w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, 60.5406(c), 60.5406a(c), 60.5407a(g), 60.5413(b), 60.5413a(b) and 60.5413a(d).

*   *   *   *   *

Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

■ 3. Section 60.105a is amended by revising paragraph (b)(2)(ii) to read as follows:

§ 60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

*   *   *   *   *

(b) * * *

(2) * * *

(ii) The owner or operator shall conduct performance evaluations of each CO_2 and O_2 monitor according to the requirements in § 60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Method 3, 3A or 3B of appendix A–2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

*   *   *   *   *

■ 4. Section 60.106a is amended by revising paragraph (a)(1)(iii) to read as follows:

§ 60.106a Monitoring of emissions and operations for sulfur recovery plants.

(a) * * *

(1) * * *

(iii) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Method 6 or 6C of appendix A–4 to part 60. The method ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6.

*   *   *   *   *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 5. The authority citation for part 63 continues to read as follows:

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

Subpart CC—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

■ 6. Section 63.641 is amended by:

■ a. Revising the definitions of ''Flare purge gas'', ''Flare supplemental gas'' and ''Relief valve'';

■ b. Adding a new definition of ''Pressure relief device''; and

■ c. Revising paragraphs (1)(i) and (ii) of the definition of ''Reference control technology for storage vessels.''

The revisions and addition read as follows:

§ 63.641 Definitions.

* * * * *

Flare purge gas means gas introduced between a flare header's water seal and the flare tip to prevent oxygen infiltration (backflow) into the flare tip or for other safety reasons. For a flare with no water seal, the function of *flare purge gas* is performed by flare sweep gas and, therefore, by definition, such a flare has no *flare purge gas.*

Flare supplemental gas means all gas introduced to the flare to improve the heat content of combustion zone gas. *Flare supplemental gas* does not include assist air or assist steam.

* * * * *

Pressure relief device means a valve, rupture disk, or similar device used only to release an unplanned, nonroutine discharge of gas from process equipment in order to avoid safety hazards or equipment damage. A pressure relief device discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause. Such devices include conventional, spring-actuated relief valves, balanced bellows relief valves, pilot-operated relief valves, rupture disks, and breaking, buckling, or shearing pin devices.

* * * * *

Reference control technology for storage vessels means either:

(1) * * *

(i) An internal floating roof, including an external floating roof converted to an internal floating roof, meeting the specifications of § 63.1063(a)(1)(i), (a)(2), and (b) and § 63.660(b)(2);

(ii) An external floating roof meeting the specifications of § 63.1063(a)(1)(ii), (a)(2), and (b) and § 63.660(b)(2); or

* * * * *

Relief valve means a type of pressure relief device that is designed to re-close after the pressure relief.

* * * * *

■ 7. Section 63.643 is amended by:

■ a. Revising paragraphs (c) introductory text, (c)(1), and (c)(1)(ii) through (iv); and

■ b. Adding a new paragraph (c)(1)(v).

The revisions and addition read as follows:

§ 63.643 Miscellaneous process vent provisions.

* * * * *

(c) An owner or operator may designate a process vent as a maintenance vent if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed or placed into service. The owner or operator does not need to designate a maintenance vent as a Group 1 or Group 2 miscellaneous process vent nor identify maintenance vents in a Notification of Compliance Status report. The owner or operator must comply with the applicable requirements in paragraphs (c)(1) through (3) of this section for each maintenance vent according to the compliance dates specified in table 11 of this subpart, unless an extension is requested in accordance with the provisions in § 63.6(i).

(1) Prior to venting to the atmosphere, process liquids are removed from the equipment as much as practical and the equipment is depressured to a control device meeting requirements in paragraphs (a)(1) or (2) of this section, a fuel gas system, or back to the process until one of the following conditions, as applicable, is met.

(i) * * *

(ii) If there is no ability to measure the LEL of the vapor in the equipment based on the design of the equipment, the pressure in the equipment served by the maintenance vent is reduced to 5 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the LEL of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) is less than 10 percent.

(iii) The equipment served by the maintenance vent contains less than 72 pounds of total volatile organic compounds (VOC).

(iv) If the maintenance vent is associated with equipment containing pyrophoric catalyst (*e.g.,* hydrotreaters and hydrocrackers) and a pure hydrogen supply is not available at the equipment at the time of the startup, shutdown, maintenance, or inspection activity, the LEL of the vapor in the equipment must be less than 20 percent, except for one event per year not to exceed 35 percent considering all such maintenance vents at the refinery.

(v) If, after applying best practices to isolate and purge equipment served by a maintenance vent, none of the applicable criterion in paragraphs (c)(1)(i) through (iv) can be met prior to installing or removing a blind flange or similar equipment blind, the pressure in the equipment served by the maintenance vent is reduced to 2 psig or less, Active purging of the equipment may be used provided the equipment pressure at the location where purge gas is introduced remains at 2 psig or less.

* * * * *

■ 8. Section 63.644 is amended by revising paragraph (c) introductory text and adding paragraph (c)(3) to read as follows:

§ 63.644 Monitoring provisions for miscellaneous process vents.

* * * * *

(c) The owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with paragraph (a) of this section either directly to the atmosphere or to a control device that does not comply with the requirements in § 63.643(a) shall comply with either paragraph (c)(1), (2), or (3) of this section. Use of the bypass at any time to divert a Group 1 miscellaneous process vent stream to the atmosphere or to a control device that does not comply with the requirements in § 63.643(a) is an emissions standards violation. Equipment such as low leg drains and equipment subject to § 63.648 are not subject to this paragraph (c).

* * * * *

(3) Use a cap, blind flange, plug, or a second valve for an open-ended valve or line following the requirements specified in § 60.482–6(a)(2), (b) and (c).

* * * * *

■ 9. Section 63.648 is amended by:

■ a. Revising the introductory text of paragraphs (a), (c), and (j);

■ b. Revising paragraphs (j)(3)(ii)(A) and (E), (j)(3)(iv), (j)(3)(v) introductory text, and (j)(4).

The revisions and additions read as follows:

§ 63.648 Equipment leak standards.

(a) Each owner or operator of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60, subpart VV, and paragraph (b) of this section except as provided in paragraphs (a)(1) through (3), and (c) through (j) of this section. Each owner or operator of a new source subject to the provisions of this subpart shall comply with subpart H of this part except as provided in paragraphs (c) through (j) of this section.

* * * * *

(c) In lieu of complying with the existing source provisions of paragraph (a) in this section, an owner or operator may elect to comply with the requirements of §§ 63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of subpart H except as provided in paragraphs (c)(1) through (12) and (e) through (j) of this section.

* * * * *

(j) Except as specified in paragraph (j)(4) of this section, the owner or operator must comply with the requirements specified in paragraphs (j)(1) and (2) of this section for pressure relief devices, such as relief valves or rupture disks, in organic HAP gas or vapor service instead of the pressure relief device requirements of § 60.482–4 or § 63.165, as applicable. Except as specified in paragraphs (j)(4) and (5) of this section, the owner or operator must also comply with the requirements specified in paragraph (j)(3) of this section for all pressure relief devices in organic HAP service.

* * * * *

(3) * * *

(ii) * * *

(A) Flow, temperature, liquid level and pressure indicators with deadman switches, monitors, or automatic actuators. Independent, non-duplicative systems within this category count as separate redundant prevention measures.

(B) * * *

(C) * * *

(D) * * *

(E) Staged relief system where initial pressure relief device (with lower set release pressure) discharges to a flare or other closed vent system and control device.

* * * * *

(iv) The owner or operator shall determine the total number of release events occurred during the calendar year for each affected pressure relief device separately. The owner or operator shall also determine the total number of release events for each pressure relief device for which the root cause analysis concluded that the root cause was a *force majeure* event, as defined in this subpart.

(v) Except for pressure relief devices described in paragraphs (j)(4) and (5) of this section, the following release events from an affected pressure relief device are a violation of the pressure release management work practice standards.

* * * * *

(4) *Pressure relief devices routed to a control device.* (i) If all releases and potential leaks from a pressure relief device are routed through a closed vent system to a control device, back into the process or to the fuel gas system, the owner or operator is not required to comply with paragraph (j)(1), (2), or (3) (if applicable) of this section.

(ii) If a pilot-operated pressure relief device is used and the primary release valve is routed through a closed vent system to a control device, back into the process or to the fuel gas system, the owner or operator is required to comply only with paragraphs (j)(1) and (2) of this section for the pilot discharge vent and is not required to comply with paragraph (j)(3) of this section for the pilot-operated pressure relief device.

(iii) If a balanced bellows pressure relief device is used and the primary release valve is routed through a closed vent system to a control device, back into the process or to the fuel gas system, the owner or operator is required to comply only with paragraphs (j)(1) and (2) of this section for the bonnet vent and is not required to comply with paragraph (j)(3) of this section for the balanced bellows pressure relief device.

(iv) Both the closed vent system and control device (if applicable) referenced in paragraphs (j)(4)(i) through (iii) of this section must meet the requirements of § 63.644. When complying with this paragraph (j)(4), all references to ''Group 1 miscellaneous process vent'' in § 63.644 mean ''pressure relief device.''

(v) If a pressure relief device complying with this paragraph (j)(4) is routed to the fuel gas system, then on and after January 30, 2019, any flares receiving gas from that fuel gas system must be in compliance with § 63.670.

* * * * *

■ 10. Section 63.655 is amended by:

■ a. Revising the introductory text of paragraph (f);

■ b. Revising paragraphs (f)(1)(i)(A)(*1*) through (*3*), (f)(1)(i)(B)(*3*), (f)(1)(i)(C)(*2*), (f)(1)(iii), (f)(2), (f)(4), (f)(6), (g)(2)(B)(*1*) and (g)(10) introductory text;

■ c. Redesignating paragraph (g)(10)(iii) as (g)(10)(iv);

■ d. Adding new paragraph (g)(10)(iii);

■ e. Revising paragraph (g)(13) introductory text and paragraphs (h)(2)(ii);

■ f. Removing and reserving paragraph (h)(5)(iii)(B);

■ g. Revising paragraph (h)(8);

■ h. Revising paragraphs (h)(9)(i) introductory text and (ii) introductory text;

■ i. Adding new paragraph (h)(10);

■ j. Revising paragraph (i)(3)(ii)(B);

■ k. Adding new paragraphs (i)(3)(ii)(C), (i)(5)(i) through (v);

■ l. Revising paragraphs (i)(7)(iii)(B) and (i)(11) introductory text;

■ m. Adding new paragraph (i)(11)(iv);

■ n. Revising paragraph (i)(12) introductory text and paragraph (i)(12)(iv); and adding new paragraph (i)(12)(vi).

The revisions and additions read as follows:

§ 63.655 Reporting and recordkeeping requirements.

* * * * *

(f) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status report within 150 days after the compliance dates specified in § 63.640(h) with the exception of Notification of Compliance Status reports submitted to comply with § 63.640(l)(3), for storage vessels subject to the compliance schedule specified in § 63.640(h)(2), and for sources listed in Table 11 of this subpart that have a compliance date on or after February 1, 2016. Notification of Compliance Status reports required by § 63.640(l)(3), for storage vessels subject to the compliance dates specified in § 63.640(h)(2), and for sources listed in Table 11 of this subpart that have a compliance date on or after February 1, 2016 shall be submitted according to paragraph (f)(6) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If the required information has been submitted before the date 150 days after the compliance date specified in § 63.640(h), a separate Notification of Compliance Status report is not required within 150 days after the compliance dates specified in § 63.640(h). If an owner or operator submits the information specified in paragraphs (f)(1) through (5) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information. Each owner or operator of a gasoline loading rack classified under Standard Industrial Classification Code 2911 located within a contiguous area and under common control with a petroleum refinery subject to the standards of this subpart shall submit the Notification of Compliance Status report required by subpart R of this part within 150 days after the compliance dates specified in § 63.640(h).

(1) * * *

(i) * * *

(A) * * *

(*1*) For each Group 1 storage vessel complying with either § 63.646 or § 63.660 that is not included in an emissions average, the method of compliance (*i.e.,* internal floating roof, external floating roof, or closed vent system and control device).

(*2*) For storage vessels subject to the compliance schedule specified in § 63.640(h)(2) that are not complying with § 63.646 or § 63.660 as applicable, the anticipated compliance date.

(*3*) For storage vessels subject to the compliance schedule specified in § 63.640(h)(2) that are complying with § 63.646 or § 63.660, as applicable, and the Group 1 storage vessels described in § 63.640(l), the actual compliance date.

(B) * * *

(*3*) If the owner or operator elects to submit the results of a performance test, identification of the storage vessel and control device for which the performance test will be submitted, and identification of the emission point(s) that share the control device with the storage vessel and for which the performance test will be conducted. If the performance test is submitted electronically through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) in accordance with § 63.655(h)(9), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the Notification of Compliance Status in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the Notification of Compliance Status is submitted.

(C) * * *

(*2*) If a performance test is conducted instead of a design evaluation, results of the performance test demonstrating that the control device achieves greater than or equal to the required control efficiency. A performance test conducted prior to the compliance date of this subpart can be used to comply with this requirement, provided that the test was conducted using EPA methods and that the test conditions are representative of current operating practices. If the performance test is submitted electronically through the EPA's Compliance and Emissions Data Reporting Interface in accordance with § 63.655(h)(9), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the Notification of Compliance Status in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the Notification of Compliance Status is submitted.

* * * * *

(iii) For miscellaneous process vents controlled by control devices required to be tested under § 63.645 of this subpart and § 63.116(c) of subpart G of this part, performance test results including the information in paragraphs (f)(1)(iii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.645 and that the test conditions are representative of current operating conditions. If the performance test is submitted electronically through the EPA's Compliance and Emissions Data Reporting Interface in accordance with § 63.655(h)(9), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the Notification of Compliance Status in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the Notification of Compliance Status is submitted.

* * * * *

(2) If initial performance tests are required by §§ 63.643 through 63.653, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source. On and after February 1, 2016, for data collected using test methods 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, you must submit the results in accordance with § 63.655(h)(9) by the date that you submit the Notification of Compliance Status, and you must include the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted in the Notification of Compliance Status. All other performance test results must be reported in the Notification of Compliance Status.

* * * * *

(4) Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status report, unless the results are required to be submitted electronically by § 63.655(h)(9). For performance evaluation results required to be submitted through CEDRI, submit the results in accordance with § 63.655(h)(9) by the date that you submit the Notification of Compliance Status and include the process unit where the CMS is installed, the parameter measured by the CMS, and the date that the performance evaluation was conducted in the Notification of Compliance Status.

* * * * *

(6) Notification of Compliance Status reports required by § 63.640(l)(3), for storage vessels subject to the compliance dates specified in § 63.640(h)(2), and for sources listed in Table 11 of this subpart that have a compliance date on or after February 1, 2016 shall be submitted no later than 60 days after the end of the 6-month period during which the change or addition was made that resulted in the Group 1 emission point or the existing Group 1 storage vessel was brought into compliance or the requirements with compliance dates on or after February 1, 2016, became effective, and may be combined with the periodic report. Six-month periods shall be the same 6-month periods specified in paragraph (g) of this section. The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1) through (f)(5) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, as part of the periodic report, or in any combination of these four. If the required information has been submitted before the date 60 days after the end of the 6-month period in which the addition of the Group 1 emission point took place, a separate Notification of Compliance Status report is not required within 60 days after the end of the 6-month period. If an owner or operator submits the information specified in paragraphs (f)(1) through (f)(5) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

* * * * *

(g) * * *

(2) * * *

(B) * * *

(*1*) A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than a 10 percent open area.

* * * * *

(10) For pressure relief devices subject to the requirements § 63.648(j), Periodic Reports must include the information specified in paragraphs (g)(10)(i) through (iv) of this section.

* * * * *

(iii) For pilot-operated pressure relief devices in organic HAP service, report each pressure release to the atmosphere through the pilot vent that equals or exceeds 72 pounds of VOC per day, including duration of the pressure release through the pilot vent and estimate of the mass quantity of each organic HAP released.

* * * * *

(13) For maintenance vents subject to the requirements in § 63.643(c), Periodic Reports must include the information specified in paragraphs (g)(13)(i) through (iv) of this section for any release exceeding the applicable limits in § 63.643(c)(1). For the purposes of this reporting requirement, owners or operators complying with § 63.643(c)(1)(iv) must report each venting event for which the lower explosive limit is 20 percent or greater; owners or operators complying with § 63.643(c)(1)(v) must report each venting event conducted under those provisions and include an explanation for each event as to why utilization of this alternative was required.

* * * * *

(h) * * *

(2) * * *

(ii) In order to afford the Administrator the opportunity to have an observer present, the owner or operator of a storage vessel equipped with an external floating roof shall notify the Administrator of any seal gap measurements. The notification shall be made in writing at least 30 calendar days in advance of any gap measurements required by § 63.120(b)(1) or (2) of subpart G or § 63.1063(d)(3) of subpart WW. The State or local permitting authority can waive this notification requirement for all or some storage vessels subject to the rule or can allow less than 30 calendar days' notice.

* * * * *

(8) For fenceline monitoring systems subject to § 63.658, each owner or operator shall submit the following information to the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) on a quarterly basis. (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The first quarterly report must be submitted once the owner or operator has obtained 12 months of data. The first quarterly report must cover the period beginning on the compliance date that is specified in Table 11 of this subpart and ending on March 31, June 30, September 30 or December 31, whichever date is the first date that occurs after the owner or operator has obtained 12 months of data (*i.e.,* the first quarterly report will contain between 12 and 15 months of data). Each subsequent quarterly report must cover one of the following reporting periods: Quarter 1 from January 1 through March 31; Quarter 2 from April 1 through June 30; Quarter 3 from July 1 through September 30; and Quarter 4 from October 1 through December 31. Each quarterly report must be electronically submitted no later than 45 calendar days following the end of the reporting period.

(i) Facility name and address.

(ii) Year and reporting quarter (*i.e.,* Quarter 1, Quarter 2, Quarter 3, or Quarter 4).

(iii) For the first reporting period and for any reporting period in which a passive monitor is added or moved, for each passive monitor: the latitude and longitude location coordinates; the sampler name; and identification of the type of sampler (*i.e.,* regular monitor, extra monitor, duplicate, field blank, inactive). The owner or operator shall determine the coordinates using an instrument with an accuracy of at least 3 meters. Coordinates shall be in decimal degrees with at least five decimal places.

(iv) The beginning and ending dates for each sampling period.

(v) Individual sample results for benzene reported in units of $\mu g/m^3$ for each monitor for each sampling period that ends during the reporting period. Results below the method detection limit shall be flagged as below the detection limit and reported at the method detection limit.

(vi) Data flags that indicate each monitor that was skipped for the sampling period, if the owner or operator uses an alternative sampling frequency under § 63.658(e)(3).

(vii) Data flags for each outlier determined in accordance with Section 9.2 of Method 325A of appendix A of this part. For each outlier, the owner or operator must submit the individual sample result of the outlier, as well as the evidence used to conclude that the result is an outlier.

(viii) Based on the information provided for the individual sample results, CEDRI will calculate the biweekly concentration difference (Δc) for benzene for each sampling period and the annual average Δc for benzene for each sampling period. The owner or operator may change these calculated values, but an explanation must be provided whenever a calculated value is changed.

(9) * * *

(i) Unless otherwise specified by this subpart, within 60 days after the date of completing each performance test as required by this subpart, the owner or operator shall submit the results of the performance tests following the procedure specified in either paragraph (h)(9)(i)(A) or (B) of this section.

* * * * *

(ii) Unless otherwise specified by this subpart, within 60 days after the date of completing each CEMS performance evaluation as required by this subpart, the owner or operator must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(9)(ii)(A) or (B) of this section.

* * * * *

(10) Extensions to electronic reporting deadlines.

(i) If you are required to electronically submit a report through the Compliance and Emissions Data Reporting Interface (CEDRI) in the EPA's Central Data Exchange (CDX), and due to a planned or actual outage of either the EPA's CEDRI or CDX systems within the period of time beginning 5 business days prior to the date that the submission is due, you will be or are precluded from accessing CEDRI or CDX and submitting a required report within the time prescribed, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description identifying the date, time and length of the outage; a rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved. The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(ii) If you are required to electronically submit a report through CEDRI in the EPA's CDX and a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. For the purposes of this paragraph, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage). If you intend to assert a claim of force majeure, you must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

* * * * *

(i) * * *

(3) * * *

(ii) * * *

(B) Block average values for 1 hour or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values; or

(C) All values that meet the set criteria for variation from previously recorded values using an automated data compression recording system.

(*1*) The automated data compression recording system shall be designed to:

(*i*) Measure the operating parameter value at least once every hour.

(*ii*) Record at least 24 values each day during periods of operation.

(*iii*) Record the date and time when monitors are turned off or on.

(*iv*) Recognize unchanging data that may indicate the monitor is not functioning properly, alert the operator, and record the incident.

(*v*) Compute daily average values of the monitored operating parameter based on recorded data.

(*2*) You must maintain a record of the description of the monitoring system and data compression recording system including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all criteria of paragraph (i)(3)(ii)(C)(*1*) of this section.

* * * * *

(5) * * *

(i) Identification of all petroleum refinery process unit heat exchangers at the facility and the average annual HAP concentration of process fluid or intervening cooling fluid estimated when developing the Notification of Compliance Status report.

(ii) Identification of all heat exchange systems subject to the monitoring requirements in § 63.654 and identification of all heat exchange systems that are exempt from the monitoring requirements according to the provisions in § 63.654(b). For each heat exchange system that is subject to the monitoring requirements in § 63.654, this must include identification of all heat exchangers within each heat exchange system, and, for closed-loop recirculation systems, the cooling tower included in each heat exchange system.

(iii) Results of the following monitoring data for each required monitoring event:

(A) Date/time of event.

(B) Barometric pressure.

(C) El Paso air stripping apparatus water flow milliliter/minute (ml/min) and air flow, ml/min, and air temperature, °Celsius.

(D) FID reading (ppmv).

(E) Length of sampling period.

(F) Sample volume.

(G) Calibration information identified in Section 5.4.2 of the ''Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources'' Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see § 63.14).

(iv) The date when a leak was identified, the date the source of the leak was identified, and the date when the heat exchanger was repaired or taken out of service.

(v) If a repair is delayed, the reason for the delay, the schedule for completing the repair, the heat exchange exit line flow or cooling tower return line average flow rate at the monitoring location (in gallons/minute), and the estimate of potential strippable hydrocarbon emissions for each required monitoring interval during the delay of repair.

* * * * *

(7) * * *

(iii) * * *

(B) The pressure or temperature of the coke drum vessel, as applicable, for the 5-minute period prior to the pre-vent draining.

* * * * *

(11) For each pressure relief device subject to the pressure release management work practice standards in § 63.648(j)(3), the owner or operator shall keep the records specified in paragraphs (i)(11)(i) through (iii) of this section. For each pilot-operated pressure relief device subject to the requirements at § 63.648(j)(4)(ii) or (iii), the owner or operator shall keep the records specified in paragraph (i)(11)(iv) of this section.

* * * * *

(iv) For pilot-operated pressure relief devices, general or release-specific records for estimating the quantity of VOC released from the pilot vent during a release event, and records of calculations used to determine the quantity of specific HAP released for any event or series of events in which 72 or more pounds of VOC are released in a day.

(12) For each maintenance vent opening subject to the requirements in § 63.643(c), the owner or operator shall keep the applicable records specified in (i)(12)(i) through (vi) of this section.

* * * * *

(iv) If complying with the requirements of § 63.643(c)(1)(iii), records used to estimate the total quantity of VOC in the equipment and the type and size limits of equipment that contain less than 72 pounds of VOC at the time of maintenance vent opening. For each maintenance vent opening for which the deinventory procedures specified in paragraph (i)(12)(i) of this section are not followed or for which the equipment opened exceeds the type and size limits established in the records specified in this paragraph, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and records used to estimate the total quantity of VOC in the equipment at the time the maintenance vent was opened to the atmosphere.

* * * * *

(vi) If complying with the requirements of § 63.643(c)(1)(v), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting actions taken to comply with other applicable alternatives and why utilization of this alternative was required, the date of maintenance vent opening, the equipment pressure and lower explosive limit of the vapors in the equipment at the time of discharge, an indication of whether active purging was performed and the pressure of the equipment during the installation or removal of the blind if active purging was used, the duration the maintenance vent was open during the blind installation or removal process, and records used to estimate the total quantity of VOC in the equipment at the time the maintenance vent was opened to the atmosphere for each applicable maintenance vent opening.

* * * * *

■ 11. Section 63.657 is amended by revising paragraphs (a)(1)(i) and (ii), (a)(2)(i) and (ii), (b)(5), and (e) to read as follows:

§ 63.657 Delayed coking unit decoking operation standards.

(a) * * *

(1) * * *

(i) An average vessel pressure of 2 psig or less determined on a rolling 60-event average; or

(ii) An average vessel temperature of 220 degrees Fahrenheit or less determined on a rolling 60-event average.

(2) * * *

(i) A vessel pressure of 2.0 psig or less for each decoking event; or

(ii) A vessel temperature of 218 degrees Fahrenheit or less for each decoking event.

* * * * *

(b) * * *

(5) The output of the pressure monitoring system must be reviewed each day the unit is operated to ensure that the pressure readings fluctuate as expected between operating and cooling/decoking cycles to verify the pressure taps are not plugged. Plugged pressure taps must be unplugged or otherwise repaired prior to the next operating cycle.

* * * * *

(e) The owner or operator of a delayed coking unit using the ''water overflow'' method of coke cooling prior to complying with the applicable requirements in paragraph (a) of this section must overflow the water to a separator or similar disengaging device that is operated in a manner to prevent entrainment of gases from the coke drum vessel to the overflow water storage tank. Gases from the separator or disengaging device must be routed to a closed blowdown system or otherwise controlled following the requirements for a Group 1 miscellaneous process vent. The liquid from the separator or disengaging device must be hardpiped to the overflow water storage tank or similarly transported to prevent exposure of the overflow water to the atmosphere. The overflow water storage tank may be an open or uncontrolled fixed-roof tank provided that a submerged fill pipe (pipe outlet below existing liquid level in the tank) is used to transfer overflow water to the tank. The owner or operator of a delayed coking unit using the ''water overflow'' method of coke cooling subject to this paragraph shall determine the coke drum vessel temperature as specified in paragraphs (c) and (d) of this section and shall not otherwise drain or vent the coke drum until the coke drum vessel temperature is at or below the applicable limits in paragraph (a)(1)(ii) or (a)(2)(ii) of this section.

* * * * *

■ 12. Section 63.658 is amended by revising paragraphs (c)(1), (c)(2), (c)(3), (d)(1), (d)(2), (e) introductory text, (e)(3)(iv), (f)(1)(i), and (f)(1)(i)(B) to read as follows:

§ 63.658 Fenceline monitoring provisions.

* * * * *

(c) * * *

(1) As it pertains to this subpart, known sources of VOCs, as used in Section 8.2.1.3 in Method 325A of appendix A of this part for siting passive monitors, means a wastewater treatment unit, process unit, or any emission source requiring control according to the requirements of this subpart, including marine vessel loading operations. For marine vessel loading operations, one passive monitor should be sited on the shoreline adjacent to the dock. For this subpart, an additional monitor is not required if the only emission sources within 50 meters of the monitoring boundary are equipment leak sources satisfying all of the conditions in paragraphs (c)(1)(i) through (iv) of this section.

(i) The equipment leak sources in organic HAP service within 50 meters of the monitoring boundary are limited to valves, pumps, connectors, sampling connections, and open-ended lines. If compressors, pressure relief devices, or agitators in organic HAP service are present within 50 meters of the monitoring boundary, the additional passive monitoring location specified in Section 8.2.1.3 in Method 325A of appendix A of this part must be used.

(ii) All equipment leak sources in gas or light liquid service (and in organic HAP service), including valves, pumps, connectors, sampling connections and open-ended lines, must be monitored using EPA Method 21 of 40 CFR part 60, appendix A–7 no less frequently than quarterly with no provisions for skip period monitoring, or according to the provisions of 63.11(c) Alternative Work practice for monitoring equipment for leaks. For the purpose of this provision, a leak is detected if the instrument reading equals or exceeds the applicable limits in paragraphs (c)(1)(ii)(A) through (E) of this section:

(A) For valves, pumps or connectors at an existing source, an instrument reading of 10,000 ppmv.

(B) For valves or connectors at a new source, an instrument reading of 500 ppmv.

(C) For pumps at a new source, an instrument reading of 2,000 ppmv.

(D) For sampling connections or open-ended lines, an instrument reading of 500 ppmv above background.

(E) For equipment monitored according to the Alternative Work practice for monitoring equipment for leaks, the leak definitions contained in 63.11 (c) (6)(i) through (iii).

(iii) All equipment leak sources in organic HAP service, including sources in gas, light liquid and heavy liquid service, must be inspected using visual, audible, olfactory, or any other detection method at least monthly. A leak is detected if the inspection identifies a potential leak to the atmosphere or if there are indications of liquids dripping.

(iv) All leaks identified by the monitoring or inspections specified in paragraphs (c)(1)(ii) or (iii) of this section must be repaired no later than 15 calendar days after it is detected with no provisions for delay of repair. If a repair is not completed within 15 calendar days, the additional passive monitor specified in Section 8.2.1.3 in Method 325A of appendix A of this part must be used.

(2) The owner or operator may collect one or more background samples if the owner or operator believes that an offsite upwind source or an onsite source excluded under § 63.640(g) may influence the sampler measurements. If the owner or operator elects to collect one or more background samples, the owner or operator must develop and submit a site-specific monitoring plan for approval according to the requirements in paragraph (i) of this section. Upon approval of the site-specific monitoring plan, the background sampler(s) should be operated co-currently with the routine samplers.

(3) If there are 19 or fewer monitoring locations, the owner or operator shall

collect at least one co-located duplicate sample per sampling period and at least one field blank per sampling period. If there are 20 or more monitoring locations, the owner or operator shall collect at least two co-located duplicate samples per sampling period and at least one field blank per sampling period. The co-located duplicates may be collected at any of the perimeter sampling locations.

* * * * *

(d) * * *

(1) If a near-field source correction is used as provided in paragraph (i)(2) of this section or if an alternative test method is used that provides time-resolved measurements, the owner or operator shall:

* * * * *

(2) For cases other than those specified in paragraph (d)(1) of this section, the owner or operator shall collect and record sampling period average temperature and barometric pressure using either an on-site meteorological station in accordance with Section 8.3.1 through 8.3.3 of Method 325A of appendix A of this part or, alternatively, using data from a United States Weather Service (USWS) meteorological station provided the USWS meteorological station is within 40 kilometers (25 miles) of the refinery.

* * * * *

(e) The owner or operator shall use a sampling period and sampling frequency as specified in paragraphs (e)(1) through (3) of this section.

* * * * *

(3) * * *

(iv) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(iii) of this section is at or below 0.9 $\mu g/m^3$ for 2 years (*i.e.,* 4 consecutive semi-annual samples), only one sample per year is required for that monitoring site. For yearly sampling, samples shall occur at least 10 months but no more than 14 months apart.

* * * * *

(f) * * *

(1) * * *

(i) Except when near-field source correction is used as provided in paragraph (i) of this section, the owner or operator shall determine the highest and lowest sample results for benzene concentrations from the sample pool and calculate Δc as the difference in these concentrations. Co-located samples must be averaged together for the purposes of determining the benzene concentration for that sampling location, and, if applicable, for determining Δc. The owner or operator shall adhere to the following procedures when one or more samples for the sampling period are below the method detection limit for benzene:

* * * * *

(B) If all sample results are below the method detection limit, the owner or operator shall use the method detection limit as the highest sample result and zero as the lowest sample result when calculating Δc.

* * * * *

■ 13. Section 63.660 is amended by revising the undesignated introductory text, paragraph (b) introductory text, paragraphs (b)(1), (e) and (i)(2) to read as follows:

§ 63.660 Storage vessel provisions.

On and after the applicable compliance date for a Group 1 storage vessel located at a new or existing source as specified in § 63.640(h), the owner or operator of a Group 1 storage vessel storing liquid with a maximum true vapor pressure less than 76.6 kilopascals (11.0 pounds per square inch) that is part of a new or existing source shall comply with either the requirements in subpart WW or SS of this part according to the requirements in paragraphs (a) through (i) of this section and the owner or operator of a Group 1 storage vessel storing liquid with a maximum true vapor pressure greater than or equal to 76.6 kilopascals (11.0 pounds per square inch) that is part of a new or existing source shall comply with the requirements in subpart SS of this part according to the requirements in paragraphs (a) through (i) of this section.

* * * * *

(b) A floating roof storage vessel complying with the requirements of subpart WW of this part may comply with the control option specified in paragraph (b)(1) of this section and, if equipped with a ladder having at least one slotted leg, shall comply with one of the control options as described in paragraph (b)(2) of this section. If the floating roof storage vessel does not meet the requirements of § 63.1063(a)(2)(i) through (a)(2)(viii) as of June 30, 2014, these requirements do not apply until the next time the vessel is completely emptied and degassed, or January 30, 2026, whichever occurs first.

(1) In addition to the options presented in §§ 63.1063(a)(2)(viii)(A) and (B) and 63.1064, a floating roof storage vessel may comply with § 63.1063(a)(2)(viii) using a flexible enclosure device and either a gasketed or welded cap on the top of the guidepole.

* * * * *

(e) For storage vessels previously subject to requirements in § 63.646, initial inspection requirements in § 63.1063(c)(1) and (2)(i) (*i.e.,* those related to the initial filling of the storage vessel) or in § 63.983(b)(1)(A), as applicable, are not required. Failure to perform other inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.

* * * * *

(i) * * *

(2) If a closed vent system contains a bypass line, the owner or operator shall comply with the provisions of either § 63.983(a)(3)(i) or (ii) for each closed vent system that contains bypass lines that could divert a vent stream either directly to the atmosphere or to a control device that does not comply with the requirements in subpart SS of this part. Except as provided in paragraphs (i)(2)(i) and (ii) of this section, use of the bypass at any time to divert a Group 1 storage vessel either directly to the atmosphere or to a control device that does not comply with the requirements in subpart SS of this part is an emissions standards violation. Equipment such as low leg drains and equipment subject to § 63.648 are not subject to this paragraph (i)(2).

* * * * *

■ 14. Section 63.670 is amended by:
■ a. Revising paragraph (f);
■ b. Revising paragraphs (h) introductory text, (h)(1), and (i) introductory text;
■ c. Adding new paragraphs (i)(5) and (6);
■ d. Revising paragraphs (j)(6);
■ h. Revising the definition of the Q_{cum} term in the equation in paragraph (k)(3);
■ i. Revising paragraph (m)(2) introductory text;
■ j. Revising the definitions of the Q_{NG2}, Q_{NG1}, and NHV_{NG} terms in the equation in paragraph (m)(2);
■ j. Revising paragraph (n)(2) introductory text and the definitions of the Q_{NG2}, Q_{NG1}, and NHV_{NG} terms in the equation in paragraph (n)(2); and
■ l. Revising paragraphs (o) introductory text, (o)(1)(ii)(B), (o)(1)(iii)(B), and (o)(3)(i). The revisions and additions read as follows:

§ 63.670 Requirements for flare control devices.

* * * * *

(f) *Dilution operating limits for flares with perimeter assist air.* Except as provided in paragraph (f)(1) of this section, for each flare actively receiving perimeter assist air, the owner or operator shall operate the flare to maintain the net heating value dilution parameter (NHVdil) at or above 22 British thermal units per square foot (Btu/ft^2) determined on a 15-minute block period basis when regulated material is being routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{dil} as specified in paragraph (n) of this section.

(1) If the only assist air provided to a specific flare is perimeter assist air intentionally entrained in lower and upper steam at the flare tip and the flare tip diameter is 9 inches or greater, the owner or operator shall comply only with the NHV_{cz} operating limit in paragraph (e) of this section for that flare.

(2) Reserved.

* * * * *

(h) *Visible emissions monitoring.* The owner or operator shall conduct an initial visible emissions demonstration using an observation period of 2 hours using Method 22 at 40 CFR part 60, appendix A–7. The initial visible emissions demonstration should be conducted the first time regulated materials are routed to the flare. Subsequent visible emissions observations must be conducted using either the methods in paragraph (h)(1) of this section or, alternatively, the methods in paragraph (h)(2) of this section. The owner or operator must record and report any instances where visible emissions are observed for more than 5 minutes during any 2 consecutive hours as specified in § 63.655(g)(11)(ii).

(1) At least once per day for each day regulated material is routed to the flare, conduct visible emissions observations using an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A–7. If at any time the owner or operator sees visible emissions while regulated material is routed to the flare, even if the minimum required daily visible emission monitoring has already been performed, the owner or operator shall immediately begin an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A–7. If visible emissions are observed for more than one continuous minute during any 5-minute observation period, the observation period using Method 22 at 40 CFR part 60, appendix A–7 must be extended to 2 hours or until 5-minutes of visible emissions are observed. Daily 5-minute Method 22 observations are not required to be conducted for days the flare does not receive any regulated material.

* * * * *

(i) *Flare vent gas, steam assist and air assist flow rate monitoring.* The owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the flare header or headers that feed the flare as well as any flare supplemental gas used. Different flow monitoring methods may be used to measure different gaseous streams that make up the flare vent gas provided that the flow rates of all gas streams that contribute to the flare vent gas are determined. If assist air or assist steam is used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of assist air and/or assist steam used with the flare. If pre-mix assist air and perimeter assist are both used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of separately measuring, calculating, and recording the volumetric flow rate of premix assist air and perimeter assist air used with the flare. Flow monitoring system requirements and acceptable alternatives are provided in paragraphs (i)(1) through (6) of this section.

* * * * *

(5) Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates.

(6) For perimeter assist air intentionally entrained in lower and upper steam, the monitored steam flow rate and the maximum design air-to-steam volumetric flow ratio of the entrainment system may be used to determine the assist air flow rate.

(j) * * *

(6) Direct compositional or net heating value monitoring is not required for gas streams that have been demonstrated to have consistent composition (or a fixed minimum net heating value) according to the methods in paragraphs (j)(6)(i) through (iii) of this section.

* * * * *

(k) * * *

(3) * * *

* * * * *

Q_{cum} = Cumulative volumetric flow over 15-minute block average period, standard cubic feet.

* * * * *

(m) * * *

(2) Owners or operators of flares that use the feed-forward calculation methodology in paragraph (l)(5)(i) of this section and that monitor gas composition or net heating value in a location representative of the cumulative vent gas stream and that directly monitor flare supplemental gas flow additions to the flare must determine the 15-minute block average NHV_{cz} using the following equation.

* * * * *

Q_{NG2} = Cumulative volumetric flow of flare supplemental gas during the 15-minute block period, scf.

Q_{NG1} = Cumulative volumetric flow of flare supplemental gas during the previous 15-minute block period, scf. For the first 15-minute block period of an event, use the volumetric flow value for the current 15-minute block period, *i.e.,* $Q_{NG1}=Q_{NG2}$.

NHV_{NG} = Net heating value of flare supplemental gas for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.

* * * * *

(n) * * *

(2) Owners or operators of flares that use the feed-forward calculation methodology in paragraph (l)(5)(i) of this section and that monitor gas composition or net heating value in a location representative of the cumulative vent gas stream and that directly monitor flare supplemental gas flow additions to the flare must determine the 15-minute block average NHV_{dil} using the following equation only during periods when perimeter assist air is used. For 15-minute block periods when there is no cumulative volumetric flow of perimeter assist air, the 15-minute block average NHV_{dil} parameter does not need to be calculated.

* * * * *

Q_{NG2} = Cumulative volumetric flow of flare supplemental gas during the 15-minute block period, scf.

Q_{NG1} = Cumulative volumetric flow of flare supplemental gas during the previous 15-minute block period, scf. For the first 15-minute block period of an event, use the volumetric flow value for the current 15-minute block period, *i.e.,* $Q_{NG1} = Q_{NG2}$.

NHV_{NG} = Net heating value of flare supplemental gas for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.

* * * * *

(o) *Emergency flaring provisions.* The owner or operator of a flare that has the potential to operate above its smokeless capacity under any circumstance shall comply with the provisions in paragraphs (o)(1) through (7) of this section.

(1) * * *

(ii) * * *

(B) Implementation of prevention measures listed for pressure relief devices in § 63.648(j)(3)(ii)(A) through (E) for each pressure relief device that can discharge to the flare.

* * * * *

(iii) * * *

(B) The smokeless capacity of the flare based on a 15-minute block average and design conditions. Note: A single value must be provided for the smokeless capacity of the flare.

* * * * *

(3) * * *

(i) The vent gas flow rate exceeds the smokeless capacity of the flare based on a 15-minute block average and visible emissions are present from the flare for more than 5 minutes during any 2 consecutive hours during the release event.

* * * * *

■ 15. Table 6 to Subpart CC is amended by revising the entries ''63.6(f)(3)'', ''63.6(h)(8)'', 63.7(a)(2)'', ''63.7(f)'', ''63.7(h)(3)'', and ''63.8(e)'' to read as follows:

TABLE 6—GENERAL PROVISIONS APPLICABILITY TO SUBPART CC [a]

Reference	Applies to subpart CC	Comment
*	*	* * * * *
63.6(f)(3)	Yes	Except the cross-references to § 63.6(f)(1) and (e)(1)(i) are changed to § 63.642(n) and performance test results may be written or electronic.
*	*	* * * * *
63.6(h)(8)	Yes	Except performance test results may be written or electronic.
*	*	* * * * *
63.7(a)(2)	Yes	Except test results must be submitted in the Notification of Compliance Status report due 150 days after compliance date, as specified in § 63.655(f) of subpart CC, unless they are required to be submitted electronically in accordance with § 63.655(h)(9). Test results required to be submitted electronically must be submitted by the date the Notification of Compliance Status report is submitted.
*	*	* * * * *
63.7(f)	Yes	Except that additional notification or approval is not required for alternatives directly specified in Subpart CC.
*	*	* * * * *
63.7(h)(3)	Yes	Yes, except site-specific test plans shall not be required, and where § 63.7(h)(3)(i) specifies waiver submittal date, the date shall be 90 days prior to the Notification of Compliance Status report in § 63.655(f).
*	*	* * * * *
63.8(e)	Yes	Except that results are to be submitted electronically if required by § 63.655(h)(9).
*	*	* * * * *

* * * * *

■ 16. Table 13 to Subpart CC is amended by revising the entry ''Hydrogen analyzer'' to read as follows:

TABLE 13—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CPMS

Parameter	Minimum accuracy requirements	Calibration requirements
*	*	* * * * *
Hydrogen analyzer	±2 percent over the concentration measured or 0.1 volume percent, whichever is greater.	Specify calibration requirements in your site specific CPMS monitoring plan. Calibration requirements should follow manufacturer's recommendations at a minimum. Where feasible, select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration occurs.
*	*	* * * * *

Subpart UUU—National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

■ 17. Section 63.1564 is amended by revising the first sentence in paragraphs (b)(4)(iii), (c)(3), and (c)(4) and revising paragraph (c)(5)(iii) to read as follows:

§ 63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?

* * * * *

(b) * * *

(4) * * *

(iii) If you elect Option 3 in paragraph (a)(1)(v) of this section, the Ni lb/hr emission limit, compute your Ni emission rate using Equation 5 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 6 and 7 of this section as follows: * * *

* * * * *

(c) * * *

(3) If you use a continuous opacity monitoring system and elect to comply with Option 3 in paragraph (a)(1)(v) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 11 of this section as follows: * * *

(4) If you use a continuous opacity monitoring system and elect to comply with Option 4 in paragraph (a)(1)(vi) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 12 of this section as follows: * * *

(5) * * *

(iii) Calculating the inlet velocity to the primary internal cyclones in feet per second (ft/sec) by dividing the average volumetric flow rate (acfm) by the cumulative cross-sectional area of the primary internal cyclone inlets (ft^2) and by 60 seconds/minute (for unit conversion).

* * * * *

■ 18. Section 63.1565 is amended by revising paragraph (a)(5)(ii) to read as follows:

§ 63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

(a) * * *

(5) * * *

(ii) You can elect to maintain the oxygen (O_2) concentration in the exhaust gas from your catalyst regenerator at or above 1 volume percent (dry basis) or 1 volume percent (wet basis with no moisture correction).

* * * * *

■ 19. Section 63.1569 is amended by revising paragraph (c)(2) to read as follows:

§ 63.1569 What are my requirements for HAP emissions from bypass lines?

* * * * *

(c) * * *

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

■ 20. Section 63.1571 is amended by revising the paragraphs (a) introductory text, (a)(5) introductory text and (a)(6) introductory text, and by revising paragraphs (d)(1) and (d)(2) to read as follows:

§ 63.1571 How and when do I conduct a performance test or other initial compliance demonstration?

(a) *When must I conduct a performance test?* You must conduct initial performance tests and report the results by no later than 150 days after the compliance date specified for your source in § 63.1563 and according to the provisions in § 63.7(a)(2) and § 63.1574(a)(3). If you are required to do a performance evaluation or test for a semi-regenerative catalytic reforming unit catalyst regenerator vent, you may do them at the first regeneration cycle after your compliance date and report the results in a followup Notification of Compliance Status report due no later than 150 days after the test. You must conduct additional performance tests as specified in paragraphs (a)(5) and (6) of this section and report the results of these performance tests according to the provisions in § 63.1575(f).

* * * * *

(5) *Periodic performance testing for PM or Ni.* Except as provided in paragraphs (a)(5)(i) and (ii) of this section, conduct a periodic performance test for PM or Ni for each catalytic cracking unit at least once every 5 years according to the requirements in Table 4 of this subpart. You must conduct the first periodic performance test no later than August 1, 2017 or within 60 days of startup of a new unit.

* * * * *

(6) *One-time performance testing for Hydrogen Cyanide (HCN).* Conduct a performance test for HCN from each catalytic cracking unit no later than August 1, 2017 or within 60 days of startup of a new unit according to the applicable requirements in paragraphs (a)(6)(i) and (ii) of this section.

* * * * *

(d) * * *

(1) If you must meet the HAP metal emission limitations in § 63.1564, you elect the option in paragraph (a)(1)(v) in § 63.1564 (Ni lb/hr), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 1 of this section as follows: * * *

(2) If you must meet the HAP metal emission limitations in § 63.1564, you elect the option in paragraph (a)(1)(vi) in § 63.1564 (Ni per coke burn-off), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 2 of this section as follows: * * *

* * * * *

■ 21. Section 63.1572 is amended by revising paragraphs (c)(1) and (d)(1) to read as follows:

§ 63.1572 What are my monitoring installation, operation, and maintenance requirements?

* * * * *

(c) * * *

(1) You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in Table 41 of this subpart. You must also meet the equipment specifications in Table 41 of this subpart if pH strips or colormetric tube sampling systems are used. You must meet the requirements in Table 41 of this subpart for BLD systems. Alternatively, before August 1, 2017, you may install, operate, and maintain each continuous parameter monitoring system in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately.

* * * * *

(d) * * *

(1) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero

and span adjustments), you must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.

* * * * *

■ 22. Section 63.1573 is amended by revising paragraph (a)(1) introductory text to read as follows:

§ 63.1573 What are my monitoring alternatives?

(a) *What are the approved alternatives for measuring gas flow rate?* (1) You may use this alternative to a continuous parameter monitoring system for the catalytic regenerator exhaust gas flow rate for your catalytic cracking unit if the unit does not introduce any other gas streams into the catalyst regeneration vent (*i.e.,* complete combustion units with no additional combustion devices). You may also use this alternative to a continuous parameter monitoring system for the catalytic regenerator atmospheric exhaust gas flow rate for your catalytic reforming unit during the coke burn and rejuvenation cycles if the unit operates as a constant pressure system during these cycles. You may also use this alternative to a continuous parameter monitoring system for the gas flow rate exiting the catalyst regenerator to determine inlet velocity to the primary internal cyclones as required in § 63.1564(c)(5) regardless of the configuration of the catalytic regenerator exhaust vent downstream of the regenerator (*i.e.,* regardless of whether or not any other gas streams are introduced into the catalyst regeneration vent). If you use this alternative, you shall use the same procedure for the performance test and for monitoring after the performance test. You shall:

* * * * *

■ 23. Section 63.1574 is amended by revising paragraph (a)(3)(ii) to read as follows:

§ 63.1574 What notifications must I submit and when?

(a) * * *

(3) * * *

(ii) For each initial compliance demonstration that includes a performance test, you must submit the notification of compliance status no later than 150 calendar days after the compliance date specified for your affected source in § 63.1563. For data collected using test methods 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, you must submit the results in accordance with § 63.1575(k)(1)(i) by the date that you submit the Notification of Compliance Status, and you must include the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted in the Notification of Compliance Status. For performance evaluations of continuous monitoring systems (CMS) measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation, you must submit the results in accordance with § 63.1575(k)(2)(i) by the date that you submit the Notification of Compliance Status, and you must include the process unit where the CMS is installed, the parameter measured by the CMS, and the date that the performance evaluation was conducted in the Notification of Compliance Status. All other performance test and performance evaluation results (*i.e.,* those not supported by EPA's ERT) must be reported in the Notification of Compliance Status.

* * * * *

■ 24. Section 63.1575 is amended by revising paragraphs (f)(1), (k)(1) introductory text and (k)(2) introductory text, and adding paragraph (l) to read as follows:

§ 63.1575 What reports must I submit and when?

* * * * *

(f) * * *

(1) A copy of any performance test or performance evaluation of a CMS done during the reporting period on any affected unit, if applicable. The report must be included in the next semiannual compliance report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, you must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method. For data collected using test methods 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, you must submit the results in accordance with § 63.1575(k)(1)(i) by the date that you submit the compliance report, and instead of including a copy of the test report in the compliance report, you must include the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted in the compliance report. For performance evaluations of CMS measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation, you must submit the results in accordance with § 63.1575(k)(2)(i) by the date that you submit the compliance report, and you must include the process unit where the CMS is installed, the parameter measured by the CMS, and the date that the performance evaluation was conducted in the compliance report. All other performance test and performance evaluation results (*i.e.,* those not supported by EPA's ERT) must be reported in the compliance report.

* * * * *

(k) * * *

(1) Unless otherwise specified by this subpart, within 60 days after the date of completing each performance test as required by this subpart, you must submit the results of the performance tests following the procedure specified in either paragraph (k)(1)(i) or (ii) of this section.

* * * * *

(2) Unless otherwise specified by this subpart, within 60 days after the date of completing each CEMS performance evaluation required by § 63.1571(a) and (b), you must submit the results of the performance evaluation following the procedure specified in either paragraph (k)(2)(i) or (ii) of this section.

* * * * *

(l) *Extensions to electronic reporting deadlines.* (1) If you are required to electronically submit a report through the Compliance and Emissions Data Reporting Interface (CEDRI) in the EPA's Central Data Exchange (CDX), and due to a planned or actual outage of either the EPA's CEDRI or CDX systems within the period of time beginning 5 business days prior to the date that the submission is due, you will be or are precluded from accessing CEDRI or CDX and submitting a required report within the time prescribed, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description identifying the date, time and length of the outage; a rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved. The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(2) If you are required to electronically submit a report through CEDRI in the EPA's CDX and a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage). If you intend to assert a claim of force majeure, you must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

■ 25. Section 63.1576 is amended by revising paragraph (a)(2)(i) to read as follows:

§ 63.1576 What records must I keep, in what form, and for how long?

(a) * * *

(2) * * *

(i) Record the date, time, and duration of each startup and/or shutdown period for which the facility elected to comply with the alternative standards in § 63.1564(a)(5)(ii) or § 63.1565(a)(5)(ii) or § 63.1568(a)(4)(ii) or (iii).

* * * * *

■ 26. Table 3 to Subpart UUU is amended by revising the table title and entries for items 2.c, 6, 7, 8 and 9 to read as follows:

* * * * *

TABLE 3 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit . . .	If you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
* * *	*	* * *
2. * * *		
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber,[2] the gas flow rate entering or exiting the control device,[1] and total liquid (or scrubbing liquor) flow rate to the control device.
* * *	*	* * *
6. Option 1a: Elect NSPS subpart J, PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Any	See item 1 of this table.
7. Option 1b: Elect NSPS subpart Ja, PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Any	The applicable continuous monitoring systems in item 2 of this table.
8. Option 1c: Elect NSPS subpart Ja, PM concentration limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Any	See item 3 of this table.
9. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	Any	The applicable continuous monitoring systems in item 2 of this table.
* * *	*	* * *

* * * * *

■ 27. Table 4 to Subpart UUU of Part 63 is amended by revising the entries for items 9.c and 10.c to read as follows:

* * * * *

TABLE 4 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS FOR METAL HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	You must . . .	Using . . .	According to these requirements . . .
* * * * * * *			
9. * * *			
	c. Determine the equilibrium catalyst Ni concentration.	XRF procedure in appendix A to this subpart1; or EPA Method 6010B or 6020 or EPA Method 7520 or 7521 in SW–8462; or an alternative to the SW–846 method satisfactory to the Administrator.	You must obtain 1 sample for each of the 3 test runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 1 of § 63.1571, if applicable.
* * * * * * *			
10. * * *			
	c. Determine the equilibrium catalyst Ni concentration.	See item 9.c. of this table	You must obtain 1 sample for each of the 3 test runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of § 63.1571, if applicable.
* * * * * * *			

* * * * *

■ 28. Table 5 to Subpart UUU is amended by revising the entry for item 3 to read as follows:

* * * * *

TABLE 5 TO SUBPART UUU OF PART 63—INITIAL COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

For each new and existing catalytic cracking unit . . .	For the following emission limit . . .	You have demonstrated compliance if . . .
* * * * * * *		
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM per coke burn-off limit.	PM emissions must not exceed 0.5 g/kg (0.5 lb PM/1,000 lb) of coke burn-off).	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 0.5 g/kg (0.5 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your BLD; CO2, O2, or CO monitor; or continuous opacity monitoring system meets the requirements in § 63.1572.
* * * * * * *		

■ 29. Table 6 to Subpart UUU is amended by revising the entries for items 1.a.ii and 7 to read as follows:

* * * * *

TABLE 6 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
1. * * *	a. * * *	

TABLE 6 TO SUBPART UUU OF PART 63—CONTINUOUS COMPLIANCE WITH METAL HAP EMISSION LIMITS FOR CATALYTIC CRACKING UNITS—Continued

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
		ii. Conducting a performance test before August 1, 2017 or within 60 days of startup of a new unit and thereafter following the testing frequency in § 63.1571(a)(5) as applicable to your unit.
* * *	* *	* *
7. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1).	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off.	See item 2 of this table.
* * *	* *	* *

■ 30. Table 10 to Subpart UUU is amended by revising the entry for item 3 to read as follows:

* * * * *

TABLE 10 TO SUBPART UUU OF PART 63—CONTINUOUS MONITORING SYSTEMS FOR ORGANIC HAP EMISSIONS FROM CATALYTIC CRACKING UNITS

For each new or existing catalytic cracking unit . . .	And you use this type of control device for your vent . . .	You shall install, operate, and maintain this type of continuous monitoring system . . .
* *	*	* * * *
3. During periods of startup, shutdown or hot standby electing to comply with the operating limit in § 63.1565(a)(5)(ii).	Any	Continuous parameter monitoring system to measure and record the concentration by volume (wet or dry basis) of oxygen from each catalyst regenerator vent. If measurement is made on a wet basis, you must comply with the limit as measured (no moisture correction).

■ 31. Table 43 to Subpart UUU is amended by revising the entry for item 2 to read as follows:

* * * * *

TABLE 43 TO SUBPART UUU OF PART 63—REQUIREMENTS FOR REPORTS

You must submit . . .	The report must contain . . .	You shall submit the report . . .
* *	* * *	* *
2. Performance test and CEMS performance evaluation data.	On and after February 1, 2016, the information specified in § 63.1575(k)(1).	Semiannually according to the requirements in § 63.1575(b) and (f).

■ 32. Table 44 to Subpart UUU is amended by revising the entries ''63.6(f)(3)'', ''63.67(h)(7)(i)'', ''63.6(h)(8)'', ''63.7(a)(2)'', ''63.7(g)'', ''63.8(e)'', ''63.10(d)(2)'', ''63.10(e)(1)–(2)'', and ''63.10(e)(4)'' to read as follows:

* * * * *

TABLE 44 TO SUBPART UUU OF PART 63—APPLICABILITY OF NESHAP GENERAL PROVISIONS TO SUBPART UUU

Citation	Subject	Applies to subpart UUU	Explanation
*	*	* *	* * *
§ 63.6(f)(3)		Yes	Except the cross-references to § 63.6(f)(1) and (e)(1)(i) are changed to § 63.1570(c) and this subpart specifies how and when the performance test results are reported.

TABLE 44 TO SUBPART UUU OF PART 63—APPLICABILITY OF NESHAP GENERAL PROVISIONS TO SUBPART UUU—Continued

Citation	Subject	Applies to subpart UUU	Explanation
* * * * * * *			
§ 63.6(h)(7)(i)	Report COM Monitoring Data from Performance Test.	Yes	Except this subpart specifies how and when the performance test results are reported.
* * * * * * *			
§ 63.6(h)(8)	Determining Compliance with Opacity/VE Standards.	Yes	Except this subpart specifies how and when the performance test results are reported.
* * * * * * *			
§ 63.7(a)(2)	Performance Test Dates	Yes	Except this subpart specifies that the results of initial performance tests must be submitted within 150 days after the compliance date.
* * * * * * *			
§ 63.7(g)	Data Analysis, Recordkeeping, Reporting.	Yes	Except this subpart specifies how and when the performance test or performance evaluation results are reported and § 63.7(g)(2) is reserved and does not apply.
* * * * * * *			
§ 63.8(e)	CMS Performance Evaluation.	Yes	Except this subpart specifies how and when the performance evaluation results are reported.
* * * * * * *			
§ 63.10(d)(2)	Performance Test Results	No	This subpart specifies how and when the performance test results are reported.
* * * * * * *			
§ 63.10(e)(1)–(2)	Additional CMS Reports	Yes	Except this subpart specifies how and when the performance evaluation results are reported.
* * * * * * *			
§ 63.10(e)(4)	COMS Data Reports	Yes	Except this subpart specifies how and when the performance test results are reported.
* * * * * * *			

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