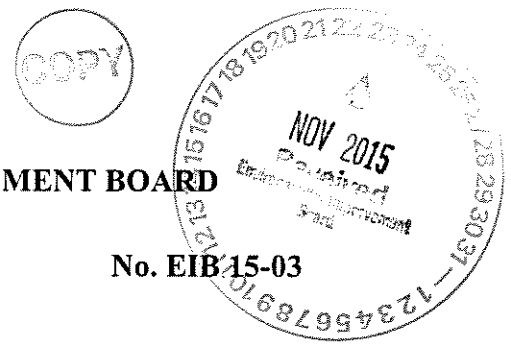


STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REPEAL OF: **No. EIB 15-03**
20.2.36 NMAC – *Petroleum Refinery - Sulfur*

NEW MEXICO ENVIRONMENT DEPARTMENT'S NOTICE OF INTENT TO PRESENT TECHNICAL TESTIMONY

Pursuant to 20.1.1.302.A NMAC, the New Mexico Environment Department ("NMED" or "Department") hereby submits its Notice of Intent to present technical testimony in this proceeding.

1. **The person for whom the witnesses will testify.**

The New Mexico Environment Department, Environmental Protection Division, Air Quality Bureau.

2. **The name and qualifications of each technical witness.**

Mark Jones. Mr. Jones is an Environmental Analyst in the Control Strategies Section of the New Mexico Environment Department Air Quality Bureau. He has worked in the Air Quality Bureau since January, 2006 in the Farmington Field Office. Mr. Jones helps to coordinate projects in the Four Corners area including the Four Corners Air Quality Group. He has developed technical knowledge and experience in emissions and emission control technology in the oil and gas industry from working in the San Juan Basin. He has also evaluated and conducted outreach on emerging federal oil and gas regulations. Mr. Jones holds a B.S. degree in Environmental Engineering from the University of California, Riverside. His resume is attached as NMED Exhibit 1.

Rita Bates. Rita Bates is the Chief of the Planning Section of the Air Quality Bureau. She has 24 years of experience in the environmental field, including 16 years with the Department. In

addition to her work for the Air Quality Bureau, Ms. Bates has worked in industry as an environmental coordinator and in environmental consulting as a project manager. Ms. Bates holds a B.S. degree in Biology from Humboldt State University. Her resume is attached as NMED Exhibit 2.

3. A Copy of the Direct Testimony of Each Witness in Narrative Form

A copy of the written direct testimony of Mr. Jones is attached as NMED Exhibit 3. Mr. Jones will present testimony regarding the proposed repeal of 20.2.36 NMAC, *Petroleum Refinery - Sulfur.* The Department does not intend to present direct testimony from Ms. Bates, but may present her as a rebuttal witness, and will make her available to assist in answering questions that may go beyond the expertise of Mr. Jones.

4. Text of Recommended Modifications to the Proposed Regulatory Change

The Department recommends that the Board adopt the proposed amendments to 20.2.36 NMAC as shown in the *Petition For Regulatory Change*, filed June 19, 2015, and as attached (without further revision) as NMED Exhibit 4.

5. List and Description of Exhibits

The Department submits the following exhibits:

Exhibit Number	Title of Exhibit
NMED 1	Resume of Mark Jones
NMED 2	Resume of Rita Bates
NMED 3	Written testimony of Mark Jones
NMED 4	Petition For Regulatory Change, No. EIB 15-03(R), including Proposed Amendments to 20.2.36 NMAC, *Petroleum Refinery – Sulfur*
NMED 5	40 CFR Part 60, Subpart J – *Standards of Performance for Petroleum Refineries*

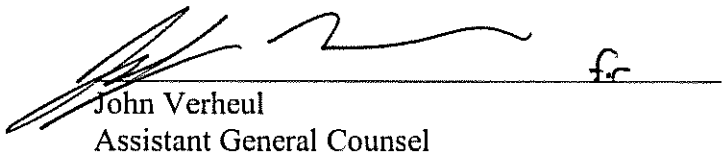
NMED 6	40 CFR Part 60, Subpart Ja –*Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007*
NMED 7	Comparison table of 20.2.36 NMAC with Federal Rules
NMED 8	Navajo Refining Quarterly Sulfur Balance Report – 1Q 2014
NMED 9	Federal and 20.2.36 NMAC Allowable Limits – Gallup Refinery
NMED 10	Stakeholder letters and public comments received
NMED 11a	Hearing Notice EIB 15-03 (R)
NMED 11b	Affidavit of Publication (New Mexico Register)
NMED 11c	Affidavit of Publication (Albuquerque Journal, English)
NMED 11d	Affidavit of Publication (Albuquerque Journal, Spanish)
NMED 12	Notice of Compliance with Small Business Regulatory Relief Act, filed August 11, 2015
NMED 13	Proposed Order and Statement of Reasons

7. **Reservation of Rights**

This *Notice of Intent* to present technical testimony is based on the Department's Petition. The Department reserves the right to call any person to testify and to present any exhibit in response to another *Notice of Intent* or public comment filed in this matter or to any testimony or exhibit offered at the public hearing. The Department also reserves the right to call any person as a rebuttal witness and to present any exhibit in support thereof.

Respectfully submitted,

NEW MEXICO ENVIRONMENT DEPARTMENT
OFFICE OF GENERAL COUNSEL



John Verheul
Assistant General Counsel
New Mexico Environment Department
PO Box 5469
Santa Fe, New Mexico 87502
John.Verheul@state.nm.us
Telephone 505-383-2063
Facsimile 505-383-2064

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Notice of Intent to Present Technical Testimony* was served on the following parties on this the 23rd day of November, 2015 via the stated delivery methods below:

Hand delivery:
Ms. Pam Castaneda, Administrator
Environmental Improvement Board
Room S-2102, Runnels Building
1190 St. Francis Dr.
Santa Fe, New Mexico 87505

Email:
Joseph M. Dworak
Assistant Attorney General
Office of the New Mexico Attorney General
P.O. Drawer 1508
Santa Fe, New Mexico 87504
jdworak@nmag.gov

Counsel for Environmental Improvement Board

John Verheul

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REPEAL OF 20.2.36 **No. EIB 15-03 (R)**

Air Quality Bureau,
Environmental Protection Division of the
New Mexico Environment Department,

Petitioner.

EXHIBIT INDEX

NMED Exhibit #	Title of Exhibit	Source
1	Resume of Mark Jones	Personal resume of Mark Jones
2	Resume of Rita Bates	Personal resume of Rita Bates
3	Written Testimony of Mark Jones	Prepared by NMED
4	Petition For Regulatory Change, No. EIB 15-03(R), including Proposed Amendments to 20.2.36 NMAC, Petroleum Refinery – Sulfur	Prepared by NMED
5	40 CFR Part 60, Subpart J – *Standards of Performance for Petroleum Refineries*	Copied from Electronic Code of Federal Regulations
6	40 CFR Part 60, Subpart Ja –*Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007*	Copied from Electronic Code of Federal Regulations
7	Comparison table of 20.2.36 NMAC with Federal Rules	Prepared by NMED
8	Navajo Refining Quarterly Sulfur Balance Report – 1Q 2014	Prepared by Navajo Refining, reviewed by NMED
9	Federal and 20.2.36 NMAC Allowable Limits – Gallup Refinery	Prepared by Western Refining, reviewed by NMED
10	Stakeholder letters and public comments received	Prepared by NMED
11a	Hearing Notice EIB 15-03 (R)	Prepared by NMED
11b	Affidavit of Publication (New Mexico Register)	New Mexico Commission of Public Records
11c	Affidavit of Publication (Albuquerque Journal, English)	The Albuquerque Journal
11d	Affidavit of Publication (Albuquerque Journal, Spanish)	The Albuquerque Journal
12	Letter to Small Business Regulatory Advisory Commission, dated August 7, 2015	Prepared by NMED
13	Proposed Order and Statement of Reasons	Prepared by NMED

MARK C. JONES

Education:

Environmental Engineering, B.S., minor in Chinese Languages, University of California-Riverside, 2000 - GPA 3.02

Renewable Energy - Photovoltaic System Design and Installation, AAS, San Juan College, 2010 - GPA 3.92

Work History:

Environmental Scientist & Specialist — **January 2006-Present**
Planning and Policy Section – Control Strategies — Farmington, New Mexico
New Mexico Environment Department (NMED)

Tasks: Led Four Corners Air Quality Initiatives

- Addressed federal ozone standards and Coordinated Four Corners Air Quality Group
  - Worked with stakeholders to develop options and control strategies
  - Led multi-agency Policy Oversight Group
  - Reviewed ozone monitoring data for compliance with the national standards
- Evaluation of NM rules Part 36 and Part 37 on refineries and gas plants
- Prepared and presented analysis, testimony and comments for Environmental Impact Statements & PSD Permit applications
- Participated in NM Clean Power Plan team towards the development of an initial state plan
- Cross-trained and assisted with Compliance/Enforcement on inspections in Northwest NM compressor stations and power plants

Research Engineer — **January 2001-January 2002**
Energy Resource Institute — Riverside, California

- Served as project coordinator for Ford diesohol/gasohol vehicle demonstration program in Thailand
- Conducted an energy, economic, and environmental life cycle analysis of Ethanol fuel in Thailand
- Represented Ford at 1999 Ethanol Bio-Fuels Conference and 2001 Clean Air World Bank Conference

Technical Publications:

1. A Systems Evaluation on the Effectiveness of a Catalyst Retrofit Program in China. Jones, M.; Wilson, R.; Norbeck, J. M.; Han, W.; Hurley, R.; Schuetzle, D.; Environmental Science & Technology (2001)
2. Reduction of Vehicular Emissions with Catalyst Retrofit, Other Documents and Presentations. Wilson, R.; Durbin, T.; Jones, M.; Schuetzle, D.; Norbeck, J.M.; 10th CRC On-Road Vehicle Emissions Workshop, San Diego, CA, March, 2000.
3. Development of a Low-Emission, Dedicated Ethanol-Fuel Vehicle With Cold-Start Distillation System
   Jones, M.; Jehlik, F., Shepard, P.; Society of Automotive Engineering (1999)

RITA BATES

EDUCATION

HUMBOLDT STATE UNIVERSITY, ARCATA, CALIFORNIA
B.S., Biology, 1990. Minor in Botany, emphasis in Ecology.

EXPERIENCE

STATE OF NEW MEXICO, ENVIRONMENT DEPARTMENT
AIR QUALITY BUREAU, PLANNING & POLICY SECTION

Section Chief, March 2005 – present
Program Manager (Natural Sciences Manager-2), March 2000 – March 2005
Environmental Specialist, December 1998 – March 2000
Environmental Scientist, August 1998 – December 1998

The Planning & Policy section of the Air Quality Bureau is responsible for the control strategy, dispersion modeling, emission inventory and small business assistance programs in the Air Quality Bureau. The control strategy section of the Air Quality Bureau is responsible for preparing state implementation plans, policies, and regulations for air quality. The modeling section ensures that all air dispersion modeling analyses submitted to our agency are accurate and complete. The Small Business Assistance Program assists small businesses in meeting air quality regulatory requirements.

EMPIRE GROUP, LLC
Empire, Nevada

Environmental Coordinator, June 1996 – July 1998

Empire Group, LLC is the parent company for several entities which own and operate a geothermal power plant, an onion and garlic dehydration plant, several ranches, and a garlic seed operation. In my position as environmental coordinator, I was responsible for permitting at all facilities.

JBR ENVIRONMENTAL CONSULTANTS, INC.
Reno, Nevada

Environmental Analyst IV, Reno Office Coordinator/Manager, July 1994 – July 1996
Environmental Analyst III, July 1993 – July 1994
Environmental Analyst I, June 1990 – July 1993

As the manager of the Reno office, I supervised seven technical staff and one administrative employee. During my employment with JBR, I worked on and managed numerous NEPA, environmental permitting and baseline projects.

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REPEAL
OF 20.2.36 NMAC – *Petroleum Refinery - Sulfur* **EIB 15-03 (R)**

WRITTEN TESTIMONY OF MARK JONES

Witness Qualifications:

Mark Jones is an Environmental Analyst in the Control Strategies Section of the New Mexico Environment Department ("NMED" or "Department") Air Quality Bureau. He has worked in the Air Quality Bureau since January, 2006 in the Farmington Field Office. Mr. Jones helps to coordinate projects in the Four Corners area including the Four Corners Air Quality Group. He has developed technical knowledge and experience in emissions and emission control technology in the oil and gas industry from working in the San Juan Basin. He has also evaluated and conducted outreach on emerging federal oil and gas regulations. Mr. Jones holds a B.S. degree in Environmental Engineering from the University of California, Riverside. His resume is attached as NMED Exhibit 1.

I. INTRODUCTION

NMED Exhibit 4 reflects the Department's proposed repeal in current New Mexico Administrative Code ("NMAC") format, with deleted material designated in strikethrough format. During my testimony, I will refer to 20.2.36 NMAC as "Part 36". The Department is proposing repeal of Part 36 to remove sulfur recovery standards for refineries from the NMAC. The federal New Source Performance Standards ("NSPS") regulations, 40 C.F.R. Part 60, Subparts J and Ja ("NSPS J and Ja") require concentration-based sulfur emission limits that are more directly related to sulfur air emissions than Part 36. Since federal regulations are in place for sulfur limits for existing and future refineries, a repeal of Part 36 would not negatively affect air quality.

The *Improving Environmental Permitting Report* (NMED, 11/14/12) recommended the repeal of this rule, saying it was outdated. This initiated an analysis of the rule beginning in 2013. A thorough analysis and stakeholder process were conducted which reinforced this recommendation.

II. REGULATORY BACKGROUND

A. New Mexico's Petroleum Refinery Sulfur Rule

Part 36 was first adopted as Air Quality Control Regulation ("AQCR") No. 622 *Petroleum Refinery – Sulfur* on July 15, 1974 (effective August 14, 1974). The rule set sulfur recovery limits (weight recovered in pounds) for existing and new refineries; established a fuel sulfur standard for fuel combustion devices; and set a limit on refinery stack heights to ensure

NMED Exhibit 3

compliance with the federal ambient air quality standard for sulfur dioxide. The regulation is not part of the federal Clean Air Act State Implementation Plan ("SIP") and, therefore, is not federally enforceable by the U.S. Environmental Protection Agency ("EPA"). It was modified slightly on May 27, 1977 to adjust the requirement in 20.2.36.109 NMAC to the following: "No person owning or operating an existing petroleum refinery shall permit, cause, suffer or allow total sulfur emissions to the atmosphere in excess of five tons in any 24-hour period." The modification was made during a time of natural gas shortage to allow Navajo Refining Company to burn a sufficient quantity of fuel oil without exceeding the former 20.2.36 NMAC emission standards.

B. EPA's NSPS for Petroleum Refineries

The EPA promulgated 40 C.F.R. Part 60, Subpart J – *Standards of Performance for Petroleum Refineries in 40 C.F.R. Part 60* (NMED Exhibit 5) on March 8, 1974 and 40 C.F.R. Part 60, Subpart Ja –*Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007* on June 24, 2008 (NMED Exhibit 6). NSPS Subpart J and Ja, were adopted by reference in 20.2.77 NMAC – *New Source Performance Standards.*

C. Comparison of Part 36 to NSPS J and Ja

Part 36 is different from the NSPS J and Ja with respect to how some of the emission limits are established and to what sources they apply. The main sources of sulfur emissions at refineries are: a) sulfur recovery unit incinerator stacks ("SRUs"), b) fluidized catalytic cracking unit regenerator stacks ("FCCUs"), and c) fuel gas combustion devices (e.g., boilers, heaters, and flares ("FGCD")). NSPS J and Ja regulate all three of these sources. Sections of Part 36 for existing refineries (constructed before July 1, 1974) covers sulfur emissions from the entire facility. Sections of Part 36 for new refineries (constructed on or after July 1, 1974) only cover certain refining processes which does not include fluid catalytic cracking units ("FCCUs"). FCCUs convert the high-boiling, high-molecular-weight hydrocarbon fractions of petroleum crude oils to more valuable gasoline, olefinic gases, and other products and can release sulfur emissions. Part 36 bases the reductions of sulfur on sulfur recovered on a mass balance (weight in pounds) that occur during some refining processes; in comparison, NSPS J and Ja require concentration based emission limits (ppmv – parts per million by volume) from specific emission release points. A table showing the comparison of Part 36 to NSPS J and Ja is shown in Exhibit 7.

D. Further Comparison of Emissions Limits at New Mexico Refineries

New Mexico currently has three operating refineries. The Gallup Refinery (Western Refining) in Gallup, NM processes approximately 23,000 barrels ("bbl") of crude oil per day. The Navajo Refining Co. (Holly Corporation) is comprised of two facilities, one in Lovington and the other in Artesia, that together have a total processing capacity of approximately 100,000 bbl crude oil/day. The Gallup and Navajo - Lovington refineries are existing refineries under Part 36, while the Navajo - Artesia refinery qualifies as a new refinery. All existing and new refineries in New Mexico are required to submit a quarterly sulfur balance report to demonstrate compliance with

their respective emission limits in Part 36. Recent sulfur balance reports for both Navajo refining facilities (Artesia and Lovington) and Gallup Refinery were used to compare the stringency of Part 36 to NSPS J and Ja. An example sulfur balance report is provided as NMED Exhibit 8.

The analysis showed that the requirements in NSPS J and Ja were more stringent than those in Part 36. NSPS J and Ja require emissions of sulfur dioxide (SO_2) $\leq$ 250 ppm. NSPS J and Ja have equivalent requirements as Part 36 for fuel gas combustion devices. NSPS J and Ja have additional requirements of $SO_2 \leq 50$ ppm from FCCUs where none exist for new refineries under Part 36.

There is an exemption to NSPS J and Ja that applies to one of the existing refineries in New Mexico. The Gallup refinery uses a type of sulfur recovery system, a sour water to ammonium thiosulfate solution ("SWAATS") recovery process that is exempt from 40 C.F.R. 63. This SWAATS unit is covered by other NMED permit requirements for H2S which can be released from a vent downstream of a wet scrubber. A regulatory comparison showing NSPS J/Ja allowable emissions as compared to the Part 36 allowable limits for Gallup Refinery (an existing refinery) was conducted (NMED Exhibit 9). The allowable emissions for J/Ja and other permit conditions was 0.54 tons sulfur per 24 hour period as compared to Part 36 allowable emissions of 5 tons per 24 hour period demonstrating that NSPS J and Ja have lower allowable emission limits regardless of the exemption.

III. PROPOSED REPEAL OF PART 36

Part 36 was adopted in 1974 at a time when Continuous Emissions Monitoring Systems ("CEMS") were not widely in use. This leads to enforceability issues due to a lack of monitoring requirements. Also, the regulation is not part of the State Implementation Plan under the federal Clean Air Act, and therefore is not federally enforceable by the EPA. In comparison, Subparts J and Ja require continuous monitoring, which provides for more effective enforcement of the emission limits.

With respect to reporting requirements, Part 36 quarterly reporting can be redundant, as subject facilities are also required to submit semi-annual reports required by NSPS J and Ja, and semiannual reports and annual compliance certifications required by Clean Air Act Title V permits. Calculating mass balance reports required by Part 36 requires the use of engineering resources at refineries, as well as Department resources to review and process the submittals.

The New Mexico Environment Department believes repeal of Part 36 would benefit the state by removing outdated, redundant requirements. Since federal regulations are in place for sulfur limits for existing and future refineries, a repeal of Part 36 would not negatively affect air quality.

IV. OUTREACH

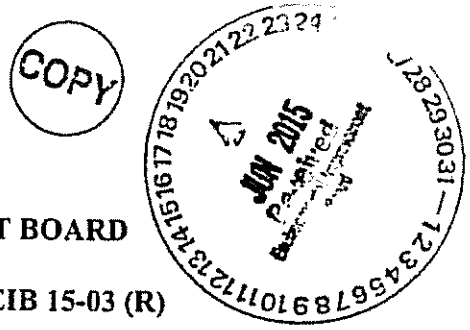
Initial outreach was conducted beginning April 1, 2014 with a stakeholder letter to industry and environmental groups announcing the evaluation of Part 36 and soliciting comments. A copy of that letter and comments received are shown as NMED Exhibit 10.

Additional outreach was conducted for the proposed repeal of Part 36 in the form of public notices (NMED Exhibits 11a-11d) and an open house. The public notice was published in the New Mexico Register on September 29, 2015 and in the Albuquerque Journal, in English and Spanish, on September 16, 2015. The Department provided an open house on October 29, 2015, at the NMED Roswell Office training room, 1914 W. Second, Roswell, NM 88201. The state received no comments from the public notices and had no attendance at the open house. The open house planned for November 2015 was cancelled due to lack of interest.

The Department also complied with the Small Business Regulatory Relief Act (NMED Exhibit 12). This Act establishes a review process, not a standard or outcome. The Department must consider the effect of the proposed rule repeal on small businesses; if the Department identifies an adverse effect, it must consider the available methods to reduce the effect, but even if there are no such methods, the Board may approve the proposed rule repeal to accomplish the objectives of the applicable law. The Department does not foresee that the proposed repeal of Part 36 will have an adverse impact on the citizens or businesses of New Mexico.

V. CONCLUSION

This concludes my testimony to the Board on our proposed repeal of Part 36. I respectfully request that the Board adopt this rule repeal at the conclusion of this hearing.



STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REPEAL OF: **No. EIB 15-03 (R)**
20.2.36 NMAC – *Petroleum Refinery - Sulfur*

PETITION FOR REGULATORY CHANGE

The Air Quality Bureau in the Environmental Protection Division of the New Mexico Environment Department petitions the Environmental Improvement Board ("Board"), pursuant to 20.1.1 NMAC - *Rulemaking Procedures*, to repeal 20.2.36 NMAC – *Petroleum Refinery - Sulfur*. The Board is authorized to adopt these amendments by the Air Quality Control Act, NMSA 1978, §§ 74-1-8 and 74-2-5. A statement of reasons for the regulatory change is attached, which includes a copy of the currently effective 20.2.36 NMAC proposed for repeal, in strikeout format.

The Air Quality Bureau requests that the Board schedule the hearing in this matter at its regular meeting to be held on December 18, 2015. The Air Quality Bureau anticipates that the hearing regarding the proposed amendments will take approximately one half hour.

Respectfully submitted,

NEW MEXICO ENVIRONMENT DEPARTMENT
OFFICE OF GENERAL COUNSEL

John Verheul
Assistant General Counsel
1190 S. St. Francis Drive, Suite N-4050
Santa Fe, New Mexico 87505
505.827.0528
john.verheul@state.nm.us

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Petition for Regulatory Change* was served on the following parties on this the 19th day of June, 2015 via the stated delivery methods below:

Hand delivery:
Ms. Pam Castaneda, Administrator
Environmental Improvement Board
Room S-2102, Runnels Building
1190 St. Francis Dr.
Santa Fe, New Mexico 87505

Email:
Joseph M. Dworak
Assistant Attorney General
Office of the New Mexico Attorney General
P.O. Drawer 1508
Santa Fe, New Mexico 87504
Counsel for Environmental Improvement Board
jdworak@nmag.gov

John Verheul

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REPEAL OF: **No. EIB 15-03 (R)**
20.2.36 NMAC – *Petroleum Refinery - Sulfur*

STATEMENT OF REASONS

The New Mexico Environment Department ("Department") Air Quality Bureau ("Bureau") proposes to repeal 20.2.36 NMAC, *Petroleum Refinery – Sulfur* ("Part 36"). Part 36 establishes sulfur limits (sulfur recovery standards) and other requirements for existing (constructed prior to July 1, 1974) and new petroleum refineries.

The federal New Source Performance Standards (NSPS) regulations, 40 CFR Part 60, Subparts J and Ja (NSPS J and Ja) require concentration-based sulfur emission limits that are more directly related to sulfur air emissions than Part 36.

The main difference between Part 36 and Subparts J and Ja is how emission limits are established and to what sources they apply. Part 36 bases the reductions of sulfur recovered on a mass balance (weight in pounds) that occurs during some refining processes; in comparison, NSPS J and Ja require concentration-based emission limits (parts per million by volume, or ppmv) from specific emission release points. Existing information contained in sulfur reporting forms submitted by permitted refineries in NM and regulatory comparisons between Part 36 and NSPS J and Ja submitted by Western Refining Company and Navajo Refining Company show that NSPS J and Ja result in control requirements that are more directly related to sulfur air emissions and their impact on air quality.

Part 36 is outdated; it was adopted in 1974 at a time when Continuous Emissions Monitoring Systems (CEMS) were not widely in use. This leads to enforceability issues due to a lack of monitoring requirements. Also, the regulation is not part of the State Implementation Plan (SIP) under the federal Clean Air Act, and therefore is not federally enforceable by the EPA. In comparison, Subparts J and Ja require continuous monitoring, which provides for more effective enforcement of the emission limits.

With respect to reporting requirements, Part 36 quarterly reporting can be redundant, as subject facilities are also required to submit semi-annual reports required by NSPS J and Ja, and semi-annual reports and annual compliance certifications required by Clean Air Act Title V permits. Calculating mass balance reports required by Part 36 requires the use of engineering resources at refineries, as well as Department resources to review and process the submittals.

The New Mexico Environment Department believes repeal of Part 36 would benefit the state by removing outdated, redundant requirements. Since federal regulations are in place for sulfur

NMED Exhibit 4

limits for existing and future refineries, a repeal of Part 36 would not negatively affect air quality.

Below is the currently effective rule that the Bureau proposes to repeal, with changes shown in redline strikeout format.

~~[TITLE 20 ENVIRONMENTAL PROTECTION~~
~~CHAPTER 2 AIR QUALITY (STATEWIDE)~~
~~PART 36 PETROLEUM REFINERY SULFUR~~

~~20.2.36.1 ISSUING AGENCY: Environmental Improvement Board.~~
~~[11/30/95; 20.2.36.1 NMAC - Rn, 20 NMAC 2.36.100 10/31/02]~~

~~20.2.36.2 SCOPE: All geographic areas within the jurisdiction of the Environmental Improvement Board.~~
~~[11/30/95; 20.2.36.2 NMAC - Rn, 20 NMAC 2.36.101 10/31/02]~~

~~20.2.36.3 STATUTORY AUTHORITY: Environmental Improvement Act, NMSA 1978, section 74-1-8(A)(4) and (7), and Air Quality Control Act, NMSA 1978, sections 74-2-1 et seq., including specifically, section 74-2-5(A), (B), and (C).~~
~~[11/30/95; 20.2.36.3 NMAC - Rn, 20 NMAC 2.36.102 10/31/02]~~

~~20.2.36.4 DURATION: Permanent.~~
~~[11/30/95; 20.2.36.4 NMAC - Rn, 20 NMAC 2.36.103 10/31/02]~~

~~20.2.36.5 EFFECTIVE DATE: November 30, 1995.~~
~~[11/30/95; 20.2.36.5 NMAC - Rn, 20 NMAC 2.36.104 10/31/02]~~
~~[The latest effective date of any section in this Part is 10/31/02.]~~

~~20.2.36.6 OBJECTIVE: The objective of this Part is to establish sulfur emission standards for petroleum refineries.~~
~~[11/30/95; 20.2.36.6 NMAC - Rn, 20 NMAC 2.36.105 10/31/02]~~

~~20.2.36.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC (Definitions), as used in this Part:~~
~~A. "Existing petroleum refinery" means a petroleum refinery the fabrication, erection or installation of which was commenced prior to July 1, 1974, and includes all vessels, boilers, heaters, condensers, cracking units, regeneration units, sour water strippers, wastewater separators, storage and loading facilities, sulfur recovery facilities, flares and other facilities interconnected in their processing operations and used in the processing of crude oil, condensate, pentanes, butanes or similar substances for the purpose of producing gasoline, fuel oil, jet fuel, diesel, asphalt or similar substances. Petroleum refinery does not include natural gas processing plants.~~
~~B. "New petroleum refinery" means petroleum refinery or part thereof the fabrication, erection, installation, or modification of which is commenced on or after July 1, 1974, and includes all vessels, boilers, heaters, condensers, cracking units, sweetening units,~~

~~regenerating units, sour water strippers, wastewater separators, storage and loading facilities, sulfur recovery facilities, flares and other facilities interconnected in their processing operations and used in the processing of crude oil, condensate, pentanes, butanes or similar substances for the purpose of producing gasoline, fuel oil, jet fuel, diesel, asphalt or similar substances. Petroleum refinery does not include natural gas processing plants.~~

~~C. "Part" means an air quality control regulation under Title 20, Chapter 2 of the New Mexico Administrative Code, unless otherwise noted, as adopted or amended by the Board.~~

~~D. "Plant processes" includes but is not limited to hydrogenation sweetening units, hydrocracking units, fuel burning equipment including flares and incinerators, sweetening system regeneration units, sour water strippers, and similar sulfur releasing systems. "Plant processes" does not include catalyst cracking regeneration units other than hydrocracking units, or boilers and process heaters if the emissions from these processes when totaled contain less than 2.5 tons of sulfur per day.~~

~~E. "Sulfur" means elemental sulfur and the sulfur component of any mixture or compound.~~

~~F. "Ton" means 2000 pounds.~~

~~[11/30/95; 20.2.36.7 NMAC - Rn, 20 NMAC 2.36.107 10/31/02]~~

~~**20.2.36.8 AMENDMENT AND SUPERSESSION OF PRIOR REGULATIONS:** This Part amends and supersedes Air Quality Control Regulation ("AQCR") 622, - Petroleum Refinery - Sulfur last filed July 16, 1986.~~

~~A. All references to AQCR 622 in any other rule shall be construed as a reference to this Part.~~

~~B. The amendment and supersession of AQCR 622 shall not affect any administrative or judicial enforcement action pending on the effective date of such amendment nor the validity of any permit issued pursuant to AQCR 622.~~

~~[11/30/95; 20.2.36.8 NMAC - Rn, 20 NMAC 2.36.106 10/31/02]~~

~~**20.2.36.9 DOCUMENTS:** Documents cited in this Part may be viewed at the New Mexico Environment Department, Air Quality Bureau, Runnels Building, 1190 Saint Francis Drive, Santa Fe, NM 87505 [2048 Galisteo St., Santa Fe, NM 87505].~~

~~[11/30/95; 20.2.36.9 NMAC - Rn, 20 NMAC 2.36.108 10/31/02]~~

~~**20.2.36.10 to 20.2.36.108 [RESERVED]**~~

~~**20.2.36.109 EXISTING PETROLEUM REFINERY:** The owner or operator of an existing petroleum refinery shall not permit, cause, suffer or allow total sulfur emissions to the atmosphere in excess of five tons in any 24 hour period.~~

~~[11/30/95; 20.2.36.109 NMAC - Rn, 20 NMAC 2.36.109 10/31/02]~~

~~**20.2.36.110 NEW PETROLEUM REFINERY - LESS THAN 30 TONS PER DAY OF SULFUR:** The owner or operator of a new petroleum refinery that releases an average of more than five tons and less than thirty tons a day of sulfur in plant processes shall not permit, cause, suffer or allow at any time sulfur emissions to the atmosphere in excess of 10 pounds of sulfur for every 100 pounds of sulfur released in plant processes.~~

[11/30/95; 20.2.36.110 NMAC - Rn, 20 NMAC 2.36.110 10/31/02]

20.2.36.111 NEW PETROLEUM REFINERY - MORE THAN 30 TONS PER DAY OF SULFUR: The owner or operator of a new petroleum refinery that releases an average of thirty tons a day or greater of sulfur in plant processes shall not permit, cause, suffer or allow at any time sulfur emissions to the atmosphere in excess of 2 pounds of sulfur for every 100 pounds of sulfur released in plant processes.

[11/30/95; 20.2.36.111 NMAC - Rn, 20 NMAC 2.36.111 10/31/02]

20.2.36.112 NEW PETROLEUM REFINERY - SULFUR CONTENT OF FUEL GAS: The owner or operator of a new petroleum refinery shall not permit, cause, suffer or allow at any time the amount of sulfur in the off-gas stream from fuel-gas burning equipment to exceed the quantity that would exist if the sulfur content of the gas used for fuel was 10 grains per 100 standard cubic feet of fuel gas.

[11/30/95; 20.2.36.112 NMAC - Rn, 20 NMAC 2.36.112 10/31/02]

20.2.36.113 REPORTING REQUIREMENTS:

A. To aid the department in determining compliance with this Part, the owner or operator of a petroleum refinery shall submit to the department quarterly reports for the periods January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31 of each year, each report to be received by the department within 45 days of the end of the quarterly period.

(1) The quarterly report shall contain the following:

(a) The sulfur content of the feedstocks entering the petroleum refinery, determined no less frequently than weekly;

(b) The sulfur content of all fuel burned in the plant and the amount of each type of fuel burned, determined no less frequently than weekly;

(c) The sulfur content of the products produced by the petroleum refinery, determined no less frequently than weekly;

(d) The sulfur content of the inlet and outlet gas stream or streams of the sulfur recovery plant determined no less frequently than monthly; and

(e) The weight of the recovered sulfur, determined no less frequently than weekly.

(2) If it appears necessary, the department may require reports on a more frequent basis, but no more frequently than monthly.

B. When the petroleum refinery has at some time during the quarterly period operated under the provisions of 20.2.7 NMAC (Excess Emissions During Malfunction, Startup, Shutdown, or Scheduled Maintenance) and complied with the notification requirements of that regulation, quantities and time periods involved in the quarterly reports may be modified to exclude the time periods and the quantities involved during those time periods if the quantities are determined separately for those time periods and submitted in the quarterly report.

[11/30/95; 20.2.36.113 NMAC - Rn, 20 NMAC 2.36.113 10/31/02]

20.2.36.114 STACK HEIGHT: The owner or operator of a petroleum refinery shall not permit, cause, suffer or allow sulfur compounds to be emitted to the atmosphere unless the sulfur is emitted from a stack of sufficient physical height or controlled by another method approved by

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~~the department to prevent concentrations of sulfur compounds near ground level equal to or greater than any state or federal ambient air standard.~~

~~[11/30/95; 20.2.36.114 NMAC - Rn, 20 NMAC 2.36.114 10/31/02]]~~

HISTORY OF 20.2.36 NMAC:

Pre-NMAC History: The material in this part was derived from that previously filed with the Commission of Public Records-State Records Center and Archives.

AQCR 621-632, Air Quality Control Regulations - 621, 622, 623, 624, 625, 626, 627, 628, 629, 630, 631, and 632, 07/15/74.

AQCR 622, Air Quality Control Regulation 622 - Petroleum Refinery - Sulfur, 02/08/83

EIB/AQCR 622, Air Quality Control Regulation 622 - Petroleum Refinery - Sulfur, 07/16/86

History of Repealed Material: [RESERVED]

Other History:

EIB/AQCR 622, Air Quality Control Regulation 622 - Petroleum Refinery - Sulfur, 07/16/86, was **renumbered** into first version of the New Mexico Administrative Code as 20 NMAC 2.36, Petroleum Refinery - Sulfur, filed 10/30/95.

20 NMAC 2.36, Petroleum Refinery - Sulfur, filed 10/30/95 was **renumbered, reformatted and replaced** by 20.2.36 NMAC, Petroleum Refinery - Sulfur, effective 10/31/02.

20.2.36 NMAC, Petroleum Refinery Sulfur, was repealed effective xx/xx/15.

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ELECTRONIC CODE OF FEDERAL REGULATIONS

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Title 40 → Chapter I → Subchapter C → Part 60 → Subpart J

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart J—Standards of Performance for Petroleum Refineries

Contents

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§60.100 Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section other than a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before May 14, 2007, or any fuel gas combustion device under paragraph (a) of this section that is also a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before June 24, 2008, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction, reconstruction or modification after October 4, 1976, and on or before May 14, 2007, is subject to the requirements of this subpart except as provided under paragraphs (c) through (e) of this section.

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction, reconstruction, or modification on or before January 17, 1984, is exempted from §60.104(b).

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(d) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction, reconstruction, or modification on or before January 17, 1984, is exempt from this subpart.

(e) Owners or operators may choose to comply with the applicable provisions of subpart Ja of this part to satisfy the requirements of this subpart for an affected facility.

(f) For purposes of this subpart, under §60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[43 FR 10868, Mar. 15, 1978, as amended at 44 FR 61543, Oct. 25, 1979; 54 FR 34026, Aug. 17, 1989; 73 FR 35865, June 24, 2008; 77 FR 56463, Sep. 12, 2012]

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§60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A.

(a) *Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

(b) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(c) *Process gas* means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) *Fuel gas* means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. Fuel gas does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units or marine tank vessel loading operations.

(e) *Process upset gas* means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) *Refinery process unit* means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) *Fuel gas combustion device* means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

(h) *Coke burn-off* means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in §60.106.

(i) *Claus sulfur recovery plant* means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(j) *Oxidation control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) *Reduction control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) *Reduced sulfur compounds* means hydrogen sulfide (H_2S), carbonyl sulfide (COS) and carbon disulfide (CS_2).

(m) *Fluid catalytic cracking unit* means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

(n) *Fluid catalytic cracking unit catalyst regenerator* means one or more regenerators (multiple regenerators) which comprise that portion of the fluid catalytic cracking unit in which coke burn-off and catalyst or contact material regeneration occurs, and includes the regenerator combustion air blower(s).

(o) *Fresh feed* means any petroleum derivative feedstock stream charged directly into the riser or reactor of a fluid catalytic cracking unit except for petroleum derivatives recycled within the fluid catalytic cracking unit, fractionator, or gas recovery unit.

(p) *Contact material* means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

(q) *Valid day* means a 24-hour period in which at least 18 valid hours of data are obtained. A "valid hour" is one in which at least 2 valid data points are obtained.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10868, Mar. 15, 1978; 44 FR 13481, Mar. 12, 1979; 45 FR 79453, Dec. 1, 1980; 54 FR 34027, Aug. 17, 1989; 73 FR 35865, June 24, 2008; 77 FR 56463, Sep. 12, 2012]

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§60.102 Standard for particulate matter.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

(1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that

permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43 grams per Gigajoule (g/GJ) (0.10 lb/million British thermal units (Btu)) of heat input attributable to such liquid or solid fossil fuel.

[39 FR 9315, Mar. 8, 1974, as amended at 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10868, Feb. 15, 1978; 54 FR 34027, Aug. 17, 1989; 65 FR 61753, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

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§60.103 Standard for carbon monoxide.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis).

[54 FR 34027, Aug. 17, 1989, as amended at 55 FR 40175, Oct. 2, 1990]

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§60.104 Standards for sulfur oxides.

Each owner or operator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air.

(ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air.

(b) Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator:

(1) With an add-on control device, reduce SO_2 emissions to the atmosphere by 90 percent or maintain SO_2 emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or

(2) Without the use of an add-on control device to reduce SO_2 emission, maintain sulfur oxides emissions calculated as SO_2 to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or

(3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight.

(c) Compliance with paragraph (b)(1), (b)(2), or (b)(3) of this section is determined daily on a 7-day rolling average basis using the appropriate procedures outlined in §60.106.

(d) A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days when complying with paragraph (b)(1) of this section.

[43 FR 10869, Mar. 15, 1978, as amended at 54 FR 34027, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

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§60.105 Monitoring of emissions and operations.

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(1) For fluid catalytic cracking unit catalyst regenerators subject to §60.102(a)(2), an instrument for continuously monitoring and recording the opacity of emissions into the atmosphere. The instrument shall be spanned at 60, 70, or 80 percent opacity.

(2) For fluid catalytic cracking unit catalyst regenerators subject to §60.103(a), an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere, except as provided in paragraph (a)(2) (ii) of this section.

(i) The span value for this instrument is 1,000 ppm CO.

(ii) A CO continuous monitoring system need not be installed if the owner or operator demonstrates that the average CO emissions are less than 50 ppm (dry basis) and also files a written request for exemption to the Administrator and receives such an exemption. The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that shall meet the requirements of Performance Specification 4 of appendix B of this part. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 and employ the sample conditioning system of Method 10A, the alternative relative accuracy test procedure in §10.1 of Performance Specification 2 may be used in place of the relative accuracy test.

(3) For fuel gas combustion devices subject to §60.104(a)(1), either an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere or monitoring as provided in paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess.

(i) The span values for this monitor are 50 ppm SO_2 and 25 percent oxygen (O_2).

(ii) The SO_2 monitoring level equivalent to the H_2S standard under §60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO_2 monitor under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

(4) Instead of the SO_2 monitor in paragraph (a)(3) of this section for fuel gas combustion devices subject to §60.104 (a)(1), an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H_2S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

(iii) The performance evaluations for this H_2S monitor under §60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(iv) The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(3) or (4) of this section for fuel gas streams that are exempt under §60.104(a)(1) and fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section will be considered inherently low in sulfur content. If the composition of a fuel gas stream changes such that it is no longer exempt under §60.104(a)(1) or it no longer meets one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section, the owner or operator must begin continuous monitoring under paragraph (a)(3) or (4) of this section within 15 days of the change.

(A) Pilot gas for heaters and flares.

(B) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(C) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, the catalytic reforming unit, the isomerization unit, and HF alkylation process units.

(D) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(5) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to §60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm SO_2 and 25 percent O_2.

(ii) The performance evaluations for this SO_2 monitor under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(6) For Claus sulfur recovery plants with reduction control systems not followed by incineration subject to §60.104(a)(2)(ii), an instrument for continuously monitoring and recording the concentration of reduced sulfur and O_2 emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span values for this monitor are 450 ppm reduced sulfur and 25 percent O_2.

(ii) The performance evaluations for this reduced sulfur (and O_2) monitor under §60.13(c) shall use Performance Specification 5 of appendix B of this part(and Performance Specification 3 of appendix B of this partfor the O_2 analyzer). Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations. If Method 3 yields O_2 concentrations below 0.25 percent during the performance specification test, the O_2 concentration may be assumed to be zero and the reduced sulfur CEMS need not include an O_2 monitor.

(7) In place of the reduced sulfur monitor under paragraph (a)(6) of this section, an instrument using an air or O_2 dilution and oxidation system to convert the reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of the resultant SO_2. The monitor shall include an oxygen monitor for correcting the data for excess oxygen.

(i) The span values for this monitor are 375 ppm SO_2 and 25 percent O_2.

(ii) For reporting purposes, the SO_2 exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO_2 (and O_2) monitor under §60.13(c) shall use Performance Specification 5. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations.

(8) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases at both the inlet and outlet of the SO_2 control device from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 90 percent reduction option under §60.104(b)(1).

(i) The span value of the inlet monitor shall be set at 125 percent of the maximum estimated hourly potential SO_2 emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential SO_2 emission concentration entering the control device.

(ii) The performance evaluations for these SO_2 monitors under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(9) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 50 ppmv emission limit under §60.104 (b)(1).

(i) The span value of the monitor shall be set at 50 percent of the maximum hourly potential SO_2 emission concentration of the control device.

(ii) The performance evaluations for this SO_2 monitor under §60.13 (c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(10) An instrument for continuously monitoring and recording concentrations of oxygen (O_2) in the gases at both the inlet and outlet of the sulfur dioxide control device (or the outlet only if specifically complying with the 50 ppmv standard)

from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator has elected to comply with §60.104(b)(1). The span of this continuous monitoring system shall be set at 10 percent.

(11) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(12) The owner or operator shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section.

(i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the §60.13(e) performance evaluation.

(ii) Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

(13) When seeking to comply with §60.104(b)(1), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in at least 22 out of 30 rolling successive calendar days.

(i) The test methods as described in §60.106(k);

(ii) A spare continuous monitoring system; or

(iii) Other monitoring systems as approved by the Administrator.

(b) An owner or operator may demonstrate that a fuel gas stream combusted in a fuel gas combustion device subject to §60.104(a)(1) that is not specifically exempted in §60.105(a)(4)(iv) is inherently low in sulfur. A fuel gas stream that is determined to be low-sulfur is exempt from the monitoring requirements in paragraphs (a)(3) and (4) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system, and the affected fuel gas combustion device(s) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high H_2S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377-86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes," 1986 Revision (incorporated by reference—see §60.17), with ranges 0-10/0-100 ppm (N = 10/1) to test the applicant fuel gas stream for H_2S; and

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device (e.g., the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out, and, therefore, should be representative of typical operating conditions affecting H_2S content in the fuel gas stream going to the loading rack flare).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section).

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator will follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an H_2S test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H_2S monitoring using daily stain sampling to demonstrate compliance. The owner or operator must begin monitoring according to the requirements in paragraphs (a)(1) or (a)(2) of this section as soon as practicable but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour H_2S concentration limit. The owner or operator must determine a rolling 365-day average using the stain sampling results; an average H_2S concentration of 5 ppmv must be used for days prior to the operation change.

(c) The average coke burn-off rate (Mg (tons) per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to §60.102, §60.103, or §60.104(b)(2).

(d) For any fluid catalytic cracking unit catalyst regenerator under §60.102 that uses an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil-fuels and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under §60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

NOTE: All averages, except for opacity, shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

(1) *Opacity.* All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under §60.105(a)(1) exceeds 30 percent.

(2) *Carbon monoxide.* All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under §60.105(a)(2) exceeds 500 ppm.

(3) *Sulfur dioxide from fuel gas combustion.* (i) All rolling 3-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under §60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

(ii) All rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under §60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

(4) *Sulfur dioxide from Claus sulfur recovery plants.* (i) All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under §60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air); or

(ii) All 12-hour periods during which the average concentration of reduced sulfur (as SO_2) as measured by the reduced sulfur continuous monitoring system under §60.105(a)(6) exceeds 300 ppm; or

(iii) All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under §60.105(a)(7) exceeds 250 ppm (dry basis, zero percent excess air).

[39 FR 9315, Mar. 8, 1974, as amended at 40 FR 46259, Oct. 6, 1975; 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10869, Mar. 15, 1978; 48 FR 23611, May 25, 1983; 50 FR 31701, Aug. 5, 1985; 54 FR 34028, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

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§60.106 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the particulate matter (PM) standards in §60.102(a) as follows:

(1) The emission rate (E) of PM shall be computed for each run using the following equation:

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Where:

E = Emission rate of PM, kg/Mg (lb/ton) of coke burn-off.

c_s = Concentration of PM, g/dscm (gr/dscf).

Q_{sd} = Volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

R_c = Coke burn-off rate, Mg/hr (ton/hr) coke.

K = Conversion factor, 1,000 g/kg (7,000 gr/lb).

(2) Method 5B or 5F is to be used to determine particulate matter emissions and associated moisture content from affected facilities without wet FGD systems; only Method 5B is to be used after wet FGD systems. The sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that

shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

(3) The coke burn-off rate (R_c) shall be computed for each run using the following equation:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r (\%CO/2 + \%CO_2 + \%O_2) + K_3 Q_{oxy} (\%O_{oxy})$$

Where:

R_c = Coke burn-off rate, kilograms per hour (kg/hr) (lb/hr).

Q_r = Volumetric flow rate of exhaust gas from fluid catalytic cracking unit regenerator before entering the emission control system, dscm/min (dscf/min).

Q_a = Volumetric flow rate of air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

Q_{oxy} = Volumetric flow rate of O_2 enriched air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

$\%CO_2$ = Carbon dioxide concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

%CO = CO concentration in FCCU regenerator exhaust, percent by volume (dry basis).

$\%O_2$ = O_2 concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the fluid catalytic cracking unit regenerator, percent by volume (dry basis).

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)].

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)].

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(i) Method 2 shall be used to determine the volumetric flow rate (Q_r).

(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine CO_2, CO, and O_2 concentrations.

(4) Method 9 and the procedures of §60.11 shall be used to determine opacity.

(c) If auxiliary liquid or solid fossil-fuels are burned in an incinerator-waste heat boiler, the owner or operator shall determine the emission rate of PM permitted in §60.102(b) as follows:

(1) The allowable emission rate (E_s) of PM shall be computed for each run using the following equation:

$$E_s = F + A (H/R_c)$$

Where:

E_s = Emission rate of PM allowed, kg/Mg (lb/ton) of coke burn-off in catalyst regenerator.

F = Emission standard, 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in catalyst regenerator.

A = Allowable incremental rate of PM emissions, 43 g/GJ (0.10 lb/million Btu).

H = Heat input rate from solid or liquid fossil fuel, GJ/hr (million Btu/hr).

R_c = Coke burn-off rate, Mg coke/hr (ton coke/hr).

(2) Procedures subject to the approval of the Administrator shall be used to determine the heat input rate.

(3) The procedure in paragraph (b)(3) of this section shall be used to determine the coke burn-off rate (R_c).

(d) The owner or operator shall determine compliance with the CO standard in §60.103(a) by using the integrated sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be 60 minutes.

(e)(1) The owner or operator shall determine compliance with the H_2S standard in §60.104(a)(1) as follows: Method 11, 15, 15A, or 16 shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line.

(i) For Method 11, the sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

(ii) For Method 15 or 16, at least three injects over a 1-hour period shall constitute a run.

(iii) For Method 15A, a 1-hour sample shall constitute a run.

(2) Where emissions are monitored by §60.105(a)(3), compliance with §60.104(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A. 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. A 1-hour sample shall constitute a run. Method 6 samples shall be taken at a rate of approximately 2 liters/min. The ppm correction factor (Method 6) and the sampling location in paragraph (f)(1) of this section apply. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C.

(f) The owner or operator shall determine compliance with the SO_2 and the H_2S and reduced sulfur standards in §60.104(a)(2) as follows:

(1) Method 6 shall be used to determine the SO_2 concentration. The concentration in mg/dscm obtained by Method 6 or 6C is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m^2 (53.8 ft^2) or at a point no closer to the walls than 1.00 m (39.4 in.) if the cross-sectional area is 5.00 m^2 or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. For Method 6C, a run shall consist of the arithmetic average of four 1-hour samples. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C. The sampling time for each sample shall be equal to the time it takes for two Method 6 samples. The moisture content from this sample shall be used to correct the corresponding Method 6 samples for moisture. For documenting the

oxidation efficiency of the control device for reduced sulfur compounds, Method 15 shall be used following the procedures of paragraph (f)(2) of this section.

(2) Method 15 shall be used to determine the reduced sulfur and H_2S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO_2 equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO_2 equivalent for each sample during the run. Method 4 shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 or 3A. The samples shall be taken simultaneously with the SO_2, reduced sulfur and H_2S, or moisture samples. The SO_2, reduced sulfur, and H_2S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(6) of this section.

(g) Each performance test conducted for the purpose of determining compliance under §60.104(b) shall consist of all testing performed over a 7-day period using Method 6 or 6C and Method 3 or 3A. To determine compliance, the arithmetic mean of the results of all the tests shall be compared with the applicable standard.

(h) For the purpose of determining compliance with §60.104(b)(1), the following calculation procedures shall be used:

(1) Calculate each 1-hour average concentration (dry, zero percent oxygen, ppmv) of sulfur dioxide at both the inlet and the outlet to the add-on control device as specified in §60.13(h). These calculations are made using the emission data collected under §60.105(a).

(2) Calculate a 7-day average (arithmetic mean) concentration of sulfur dioxide for the inlet and for the outlet to the add-on control device using all of the 1-hour average concentration values obtained during seven successive 24-hour periods.

(3) Calculate the 7-day average percent reduction using the following equation:

$$Rso_2 = 100(Cso_2(i) - Cso_2(o)) / Cso_2(i)$$

where:

Rso_2 = 7-day average sulfur dioxide emission reduction, percent

$Cso_2(i)$ = sulfur dioxide emission concentration determined in §60.106(h)(2) at the inlet to the add-on control device, ppmv

$Cso_2(o)$ = sulfur dioxide emission concentration determined in §60.106(h)(2) at the outlet to the add-on control device, ppmv

100 = conversion factor, decimal to percent

(4) Outlet concentrations of sulfur dioxide from the add-on control device for compliance with the 50 ppmv standard, reported on a dry, O_2-free basis, shall be calculated using the procedures outlined in §60.106(h)(1) and (2) above, but for the outlet monitor only.

(5) If supplemental sampling data are used for determining the 7-day averages under paragraph (h) of this section and such data are not hourly averages, then the value obtained for each supplemental sample shall be assumed to represent the hourly average for each hour over which the sample was obtained.

(6) For the purpose of adjusting pollutant concentrations to zero percent oxygen, the following equation shall be used:

$C_{adj} = C_{meas}[20.9_c/(20.9-\%O_2)]$

where:

C_{adj} = pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm

20.9_c = 20.9 percent oxygen−0.0 percent oxygen (defined oxygen correction basis), percent

20.9 = oxygen concentration in air, percent

$\%O_2$ = oxygen concentration measured on a dry basis, percent

(i) For the purpose of determining compliance with §60.104(b)(2), the following reference methods and calculation procedures shall be used except as provided in paragraph (i)(12) of this section:

(1) One 3-hour test shall be performed each day.

(2) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 8 as modified in §60.106(i)(3) for moisture content and for the concentration of sulfur oxides calculated as sulfur dioxide,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 calculation procedures (data obtained from Methods 3 and 8) for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) Method 8 shall be modified by the insertion of a heated glass fiber filter between the probe and first impinger. The probe liner and glass fiber filter temperature shall be maintained above 160 °C (320 °F). The isopropanol impinger shall be eliminated. Sample recovery procedures described in Method 8 for container No. 1 shall be eliminated. The heated glass fiber filter also shall be excluded; however, rinsing of all connecting glassware after the heated glass fiber filter shall be retained and included in container No. 2. Sampled volume shall be at least 1 dscm.

(4) For Method 3, the integrated sampling technique shall be used.

(5) Sampling time for each run shall be at least 3 hours.

(6) All testing shall be performed at the same location. Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator-waste heat boiler in which auxiliary or supplemental gaseous, liquid, or solid fossil fuel is burned, testing shall be conducted at a point between the regenerator outlet and the incinerator-waste heat boiler. An alternative sampling location after the waste heat boiler may be used if alternative coke burn-off rate equations, and, if requested, auxiliary/supplemental fuel SO_X credits, have been submitted to and approved by the Administrator prior to sampling.

(7) Coke burn-off rate shall be determined using the procedures specified under paragraph (b)(3) of this section, unless paragraph (i)(6) of this section applies.

(8) Calculate the concentration of sulfur oxides as sulfur dioxide using equation 8-3 in Section 6.5 of Method 8 to calculate and report the total concentration of sulfur oxides as sulfur dioxide (Cso_x).

(9) Sulfur oxides emission rate calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$E_{so_x} = C_{so_x} Q_{sd} / K$$

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Where:

E_{SO_x} = sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr)

C_{SO_x} = sulfur oxides emission concentration calculated as sulfur dioxide, g/dscm (gr/dscf)

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

K = 1,000 g/kg (7,000 gr/lb)

(10) Sulfur oxides emissions calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$R_{so_x} = \left(E_{so_x} / R_c\right)$$

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Where:

R_{SO_x} = Sulfur oxides emissions calculated as kg sulfur dioxide per Mg (lb/ton) coke burn-off.

E_{SO_x} = Sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr).

R_c = Coke burn-off rate, Mg/hr (ton/hr).

(11) Calculate the 7-day average sulfur oxides emission rate as sulfur dioxide per Mg (ton) of coke burn-off by dividing the sum of the individual daily rates by the number of daily rates summed.

(12) An owner or operator may, upon approval by the Administrator, use an alternative method for determining compliance with §60.104(b)(2), as provided in §60.8(b). Any requests for approval must include data to demonstrate to the Administrator that the alternative method would produce results adequate for the determination of compliance.

(j) For the purpose of determining compliance with §60.104(b)(3), the following analytical methods and calculation procedures shall be used:

(1) One fresh feed sample shall be collected once per 8-hour period.

(2) Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods: ASTM D129-64, 78, or 95, ASTM D1552-83 or 95, ASTM D2622-87, 94, or 98, or ASTM D1266-87, 91, or 98. (These methods are incorporated by reference: see §60.17.) The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Administrator.

(3) If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:

(i) Individual samples shall be collected once per 8-hour period for each separate fresh feed stream charged directly into the riser or reactor of the fluid catalytic cracking unit. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.

(ii) Each fresh feed sample shall be analyzed separately using the methods specified under paragraph (j)(2) of this section.

(iii) Fresh feed sulfur content shall be calculated for each 8-hour period using the following equation:

$$S_f = \sum_{i=1}^{n} \frac{S_i Q_i}{Q_f}$$

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where:

S_f = fresh feed sulfur content expressed in percent by weight of fresh feed.

n = number of separate fresh feed streams charged directly to the riser or reactor of the fluid catalytic cracking unit.

Q_f = total volumetric flow rate of fresh feed charged to the fluid catalytic cracking unit.

S_i = fresh feed sulfur content expressed in percent by weight of fresh feed for the "ith" sampling location.

Q_i = volumetric flow rate of fresh feed stream for the "ith" sampling location.

(4) Calculate a 7-day average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven successive 24-hour periods.

(k) The test methods used to supplement continuous monitoring system data to meet the minimum data requirements in §60.104(d) will be used as described below or as otherwise approved by the Administrator.

(1) Methods 6, 6B, or 8 are used. The sampling location(s) are the same as those specified for the monitor.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average. A minimum of 18 valid samples is required to obtain one valid day of data.

(3) For Method 6B, collection of a sample representing a minimum of 18 hours is required to obtain one valid day of data.

(4) For Method 8, the procedures as outlined in this section are used. The equivalent of 16 hours of sampling is required to obtain one valid day of data.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10869, Mar. 15, 1978; 51 FR 42842, Nov. 26, 1986; 52 FR 20392, June 1, 1987; 53 FR 41333, Oct. 21, 1988; 54 FR 34028, Aug. 17, 1989; 55 FR 40176, Oct. 2, 1990; 56 FR 4176, Feb. 4, 1991; 65 FR 61754, Oct. 17, 2000; 71 FR 55127, Sept. 21, 2006; 73 FR 35867, June 24, 2008; 77 FR 56463, Sep. 12, 2012]

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§60.107 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.104(b) shall notify the Administrator of the specific provisions of §60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by §60.7(a)(3). If an owner or operator elects at a later date to comply with an alternative provision of §60.104(b), then the Administrator shall be notified by the owner or operator in the report described in paragraph (c) of this section.

(b) Each owner or operator subject to §60.104(b) shall record and maintain the following information:

(1) If subject to §60.104(b)(1),

(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;

(ii) Measurements obtained by supplemental sampling (refer to §60.105(a)(13) and §60.106(k)) for meeting minimum data requirements; and

(iii) The written procedures for the quality control program required by appendix F, Procedure 1.

(2) If subject to §60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if §60.106(i)(12) applies.

(3) If subject to §60.104(b)(3), data obtained from the daily feed sulfur tests.

(4) Each 7-day rolling average compliance determination.

(c) Each owner or operator subject to §60.104(b) shall submit a report except as provided by paragraph (d) of this section. The following information shall be contained in the report:

(1) Any 7-day period during which:

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, O_2-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with §60.104(b)(1) is below 90 percent and above 50 ppmv, as measured by the continuous monitoring system prescribed under §60.105(a)(8), or above 50 ppmv, as measured by the outlet continuous monitoring system prescribed under §60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under §60.106(h);

(ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with §60.104(b)(2) exceeds 9.8 kg SO_X per 1,000 kg coke burn-off, as measured by the daily testing prescribed under §60.106(i). The average emission rate shall be determined using the procedures specified under §60.106(i); and

(iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with §60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under §60.106(j).

(2) Any 30-day period in which the minimum data requirements specified in §60.104(d) are not obtained.

(3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:

(i) The date that the exceedance occurred;

(ii) An explanation of the exceedance;

(iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and

(iv) A description of the corrective action taken, if any.

(4) If subject to §60.104(b)(1),

(i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;

(ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;

(iii) Identification of times when hourly averages have been obtained based on manual sampling methods;

(iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and

(v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(5) If subject to §60.104(b)(2), for each day in which a Method 8 sample result required by §60.106(i) was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by the Administrator.

(6) If subject to §60.104(b)(3), for each 8-hour period in which a feed sulfur measurement required by §60.106(j) was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Administrator.

(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(e) For each fuel gas stream combusted in a fuel gas combustion device subject to §60.104(a)(1), if an owner or operator determines that one of the exemptions listed in §60.105(a)(4)(iv) applies to that fuel gas stream, the owner or operator shall maintain records of the specific exemption chosen for each fuel gas stream. If the owner or operator applies for the exemption described in §60.105(a)(4)(iv)(D), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(f) The owner or operator of an affected facility shall submit the reports required under this subpart to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(g) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

[54 FR 34029, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7465, Feb. 12, 1999; 65 FR 61755, Oct. 17, 2000; 73 FR 35867, June 24, 2008]

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§60.108 Performance test and compliance provisions.

(a) Section 60.8(d) shall apply to the initial performance test specified under paragraph (c) of this section, but not to the daily performance tests required thereafter as specified in §60.108(d). Section 60.8(f) does not apply when determining compliance with the standards specified under §60.104(b). Performance tests conducted for the purpose of determining compliance under §60.104(b) shall be conducted according to the applicable procedures specified under §60.106.

(b) Owners or operators who seek to comply with §60.104(b)(3) shall meet that standard at all times, including periods of startup, shutdown, and malfunctions.

(c) The initial performance test shall consist of the initial 7-day average calculated for compliance with §60.104(b)(1), (b)(2), or (b)(3).

(d) After conducting the initial performance test prescribed under §60.8, the owner or operator of a fluid catalytic cracking unit catalyst regenerator subject to §60.104(b) shall conduct a performance test for each successive 24-hour period thereafter. The daily performance tests shall be conducted according to the appropriate procedures specified under §60.106. In the event that a sample collected under §60.106(i) or (j) is accidentally lost or conditions occur in which one of the samples must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operators' control, compliance may be determined using available data for the 7-day period.

(e) Each owner or operator subject to §60.104(b) who has demonstrated compliance with one of the provisions of §60.104(b) but a later date seeks to comply with another of the provisions of §60.104(b) shall begin conducting daily performance tests as specified under paragraph (d) of this section immediately upon electing to become subject to one of the other provisions of §60.104(b). The owner or operator shall furnish the Administrator with a written notification of the change in the semiannual report required by §60.107(f).

[54 FR 34030, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7466, Feb. 12, 1999; 73 FR 35867, June 24, 2008]

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§60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which shall not be delegated to States:

(1) Section 60.105(a)(13)(iii),

(2) Section 60.106(i)(12).

[54 FR 34031, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990]

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Title 40 → Chapter I → Subchapter C → Part 60 → Subpart Ja

Title 40: Protection of Environment
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Contents

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Table 1 to Subpart Ja of Part 60—Molar Exhaust Volumes and Molar Heat Content of Fuel Gas Constituents

SOURCE: 73 FR 35867, June 24, 2008, unless otherwise noted.

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§60.100a Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. The sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Except for flares and delayed coking units, the provisions of this subpart apply only to affected facilities under paragraph (a) of this section which commence construction, modification or reconstruction after May 14, 2007. For flares, the provisions of this subpart apply only to flares which commence construction, modification or reconstruction after June 24, 2008. For the purposes of this subpart, a modification to a flare commences when a project that includes any of the activities in paragraphs (c)(1) or (2) of this section is commenced. For delayed coking units, the provisions of this subpart apply to delayed coking units that commence construction, reconstruction or modification on the earliest of the following dates:

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(1) May 14, 2007, for such activities that involve a "delayed coking unit" defined as follows: one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors;

(2) December 22, 2008, for such activities that involve a "delayed coking unit" defined as follows: a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A delayed coking unit consists of the coke drums and associated fractionator;

(3) September 12, 2012, for such activities that involve a "delayed coking unit" as defined in §60.101a.

(c) For all affected facilities other than flares, the provisions in §60.14 regarding modification apply. As provided in §60.14(f), the special provisions set forth under this subpart shall supersede the provisions in §60.14 with respect to flares. For the purposes of this subpart, a modification to a flare occurs as provided in paragraphs (c)(1) or (2) of this section.

(1) Any new piping from a refinery process unit, including ancillary equipment, or a fuel gas system is physically connected to the flare (*e.g.*, for direct emergency relief or some form of continuous or intermittent venting). However, the connections described in paragraphs (c)(1)(i) through (vii) of this section are not considered modifications of a flare.

(i) Connections made to install monitoring systems to the flare.

(ii) Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.*, addition of compressors or recycle lines).

(iii) Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.

(iv) Connections made for flare gas sulfur removal.

(v) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(vi) Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved.

(vii) Connections that interconnect two or more flares.

(2) A flare is physically altered to increase the flow capacity of the flare.

(d) For purposes of this subpart, under §60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the relevant applicability date specified in paragraph (b) of this section.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012]

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§60.101a Definitions.

Terms used in this subpart are defined in the Clean Air Act (CAA), in §60.2 and in this section.

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Air preheat means a device used to heat the air supplied to a process heater generally by use of a heat exchanger to recover the sensible heat of exhaust gas from the process heater.

Ancillary equipment means equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents and continuous analyzer vents.

Cascaded flare system means a series of flares connected to one flare gas header system arranged with increasing pressure set points so that discharges will be initially directed to the first flare in the series (*i.e.*, the primary flare). If the discharge pressure exceeds a set point at which the flow to the primary flare would exceed the primary flare's capacity, flow will be diverted to the second flare in the series. Similarly, flow would be diverted to a third (or fourth) flare if the pressure in the flare gas header system exceeds a threshold where the flow to the first two (or three) flares would exceed their capacities.

Co-fired process heater means a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels on a routine basis. Process heaters that have gas burners with emergency oil back-up burners are not considered co-fired process heaters.

Coke burn-off means the coke removed from the surface of the FCCU catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in §60.104a.

Contact material means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

Corrective action means the design, operation and maintenance changes that one takes consistent with good engineering practice to reduce or eliminate the likelihood of the recurrence of the primary cause and any other contributing cause(s) of an event identified by a root cause analysis as having resulted in a discharge of gases to an affected flare in excess of specified thresholds.

Corrective action analysis means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety and secondary impacts.

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; and the coke drum blowdown recovery compressor system.

Emergency flare means a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. For purposes of this rule, a flare cannot be categorized as an *emergency flare* unless it maintains a water seal.

Flare means a combustion device that uses an uncontrolled volume of air to burn gases. The *flare* includes the foundation, flare tip, structural support, burner, igniter, flare controls, including air injection or steam injection systems, flame arrestors and the flare gas header system. In the case of an interconnected flare gas header system, the *flare* includes each individual flare serviced by the interconnected flare gas header system and the interconnected flare gas header system.

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Flare gas header system means all piping and knockout pots, including those in a subheader system, used to collect and transport gas to a flare either from a process unit or a pressure relief valve from the fuel gas system, regardless of whether or not a flare gas recovery system draws gas from the *flare gas header system*. The *flare gas header system* includes piping inside the battery limit of a process unit if the purpose of the piping is to transport gas to a flare or knockout pot that is part of the flare.

Flare gas recovery system means a system of one or more compressors, piping and the associated water seal, rupture disk or similar device used to divert gas from the flare and direct the gas to the fuel gas system or to a fuel gas combustion device.

Flexicoking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced and then gasified to produce a synthetic fuel gas.

Fluid catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. When *fluid catalyst cracking unit* regenerator exhaust from two separate fluid catalytic cracking units share a common exhaust treatment (e.g., CO boiler or wet scrubber), the *fluid catalytic cracking unit* is a single affected facility.

Fluid coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The *fluid coking unit* includes the coking reactor, the coking burner, and equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

Forced draft process heater means a process heater in which the combustion air is supplied under positive pressure produced by a fan at any location in the inlet air line prior to the point where the combustion air enters the process heater or air preheat. For the purposes of this subpart, a process heater that uses fans at both the inlet air side and the exhaust air side (*i.e.*, balanced draft system) is considered to be a *forced draft process heater*.

Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. *Fuel gas* includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. *Fuel gas* does not include gases generated by catalytic cracking unit catalyst regenerators, coke calciners (used to make premium grade coke) and fluid coking burners, but does include gases from flexicoking unit gasifiers and other gasifiers. *Fuel gas* does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations or asphalt processing units (*i.e.*, asphalt blowing stills).

Fuel gas combustion device means any equipment, such as process heaters and boilers, used to combust fuel gas. For the purposes of this subpart, *fuel gas combustion device* does not include flares or facilities in which gases are combusted to produce sulfur or sulfuric acid.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects refinery fuel gas from one or more sources for treatment as necessary prior to combusting in process heaters or boilers. A *fuel gas system* may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the refinery.

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Natural draft process heater means any process heater in which the combustion air is supplied under ambient or negative pressure without the use of an inlet air (forced draft) fan. For the purposes of this subpart, a *natural draft process heater* is any process heater that is not a forced draft process heater, including induced draft systems.

Non-emergency flare means any flare that is not an emergency flare as defined in this subpart.

Oxidation control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide (SO_2) and recycling the SO_2 to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the SO_2 to a sulfur product.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. A facility that produces only oil shale or tar sands-derived crude oil for further processing at a petroleum refinery using only solvent extraction and/or distillation to recover diluent is not a *petroleum refinery*.

Primary flare means the first flare in a cascaded flare system.

Process heater means an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam.

Process upset gas means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.

Purge gas means gas introduced between a flare's water seal and a flare's tip to prevent oxygen infiltration (backflow) into the flare tip. For flares with no water seals, the function of *purge gas* is performed by sweep gas (*i.e.*, flares without water seals do not use *purge gas*).

Reduced sulfur compounds means hydrogen sulfide (H_2S), carbonyl sulfide, and carbon disulfide.

Reduction control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to H_2S and either recycling the H_2S to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the H_2S to a sulfur product.

Refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted.

Root cause analysis means an assessment conducted through a process of investigation to determine the primary cause, and any other contributing cause(s), of a discharge of gases in excess of specified thresholds.

Secondary flare means a flare in a cascaded flare system that provides additional flare capacity and pressure relief to a flare gas system when the flare gas flow exceeds the capacity of the primary flare. For purposes of this subpart, a *secondary flare* is characterized by infrequent use and must maintain a water seal.

Sulfur pit means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. *A sulfur pit* does not include secondary sulfur storage vessels downstream of the initial Claus reactor sulfur pits.

Sulfur recovery plant means all process units which recover sulfur from H_2S and/or SO_2 from a common source of sour gas produced at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered

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sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits and, if present, oxidation or reduction control systems or incinerator, thermal oxidizer or similar combustion device. Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. *Sulfur recovery plants* that receive source gas from completely segregated sour gas treatment systems are separate affected facilities.

Sweep gas means the gas introduced in a flare gas header system to maintain a constant flow of gas to prevent oxygen buildup in the flare header. For flares with no water seals, *sweep gas* also performs the function of preventing oxygen infiltration (backflow) into the flare tip.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012; 78 FR 76756, Dec. 19, 2013]

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§60.102a Emissions limitations.

(a) Each owner or operator that is subject to the requirements of this subpart shall comply with the emissions limitations in paragraphs (b) through (i) of this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first.

(b) An owner or operator subject to the provisions of this subpart shall not discharge or cause the discharge into the atmosphere from any FCCU or FCU:

(1) Particulate matter (PM) in excess of the limits in paragraphs (b)(1)(i), (ii), or (iii) of this section.

(i) 1.0 kilogram per Megagram (kg/Mg)(1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

(ii) 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for each newly constructed FCCU.

(iii) 1.0 kg/Mg (1 lb/1,000 lb) coke burn-off; or if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

(2) Nitrogen oxides (NO_X) in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

(3) Sulfur dioxide (SO_2) in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

(4) Carbon monoxide (CO) in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

(c) The owner or operator of a FCCU or FCU that uses a continuous parameter monitoring system (CPMS) according to §60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (2) of this section.

(1) If the FCCU or FCU is controlled using an electrostatic precipitator:

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(i) The 3-hour rolling average total power and secondary current to the entire system must not fall below the level established during the most recent performance test; and

(ii) The daily average exhaust coke burn-off rate must not exceed the level established during the most recent performance test.

(2) If the FCCU or FCU is controlled using a wet scrubber:

(i) The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

(ii) The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

(d) If an FCCU or FCU uses a continuous opacity monitoring system (COMS) according to the alternative monitoring option in §60.105a(e), the 3-hour rolling average opacity of emissions from the FCCU or FCU as measured by the COMS must not exceed the site-specific opacity limit established during the most recent performance test.

(e) The owner or operator of a FCCU or FCU that is exempted from the requirement for a CO continuous emissions monitoring system under §60.105a(h)(3) shall comply with the parameter operating limits in paragraph (e)(1) or (2) of this section.

(1) For a FCCU or FCU with no post-combustion control device:

(i) The hourly average temperature of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(ii) The hourly average oxygen (O_2) concentration of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(2) For a FCCU or FCU with a post-combustion control device:

(i) The hourly average temperature of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(ii) The hourly average O_2 concentration of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(f) Except as provided in paragraph (f)(3), each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraphs (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a capacity greater than 20 long tons per day (LTD):

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 250 ppmv limit for each process train or release point or comply with a flow rate weighted average of 250 ppmv for all release points from the sulfur recovery plant; or

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(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 300 ppmv of reduced sulfur compounds and 10 ppmv of H_2S, each calculated as ppmv SO_2 (dry basis) at 0-percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 1 of this section:

$$E_{LS} = k_1 \times \left\{-0.038 * (\%O_2)^2 + 11.53 * \%O_2 + 25.6\right\} \quad \text{(Eq. 1)}$$

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Where:

E_{LS} = Emission rate of SO_2 for large sulfur recovery plant, ppmv;

k_1 = Constant factor for emission limit conversion: $k_1 = 1$ for converting to SO_2 limit and $k_1 = 1.2$ for converting to the reduced sulfur compounds limit; and

$\%O_2$ = O_2 concentration to the SRP, percent by volume (dry basis).

(2) For a sulfur recovery plant with a capacity of 20 LTD or less:

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 2,500 ppm by volume (dry basis) of SO_2 at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 2,500 ppmv limit for each process train or release point or comply with a flow rate weighted average of 2,500 ppmv for all release points from the sulfur recovery plant; or

(ii) For sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 3,000 ppm by volume of reduced sulfur compounds and 100 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 2 of this section:

$$E_{SS} = k_1 \times \left\{-0.38 * (\%O_2)^2 + 115.3 * \%O_2 + 256\right\} \quad \text{(Eq. 2)}$$

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Where:

E_{SS} = Emission rate of SO_2 for small sulfur recovery plant, ppmv.

(3) Periods of maintenance of the sulfur pit, during which the emission limits in paragraphs (f)(1) and (2) shall not apply, shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emissions limits in paragraphs (g)(1) and (2) of this section.

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(1) Except as provided in (g)(1)(iii) of this section, for each fuel gas combustion device, the owner or operator shall comply with either the emission limit in paragraph (g)(1)(i) of this section or the fuel gas concentration limit in paragraph (g)(1)(ii) of this section.

(i) The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(iii) The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr) on a higher heating value basis, the owner or operator shall not discharge to the atmosphere any emissions of NO_X in excess of the applicable limits in paragraphs (g)(2)(i) through (iv) of this section.

(i) For each natural draft process heater, comply with the limit in either paragraph (g)(2)(i)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in §60.107a; if fuel gas composition is not monitored as specified in §60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(i)(A) of this section.

(A) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.040 pounds per million British thermal units (lb/MMBtu) higher heating value basis determined daily on a 30-day rolling average basis.

(ii) For each forced draft process heater, comply with the limit in either paragraph (g)(2)(ii)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in §60.107a; if fuel gas composition is not monitored as specified in §60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(ii)(A) of this section.

(A) 60 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.060 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis.

(iii) For each co-fired natural draft process heater, comply with the limit in either paragraph (g)(2)(iii)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 3 of this section:

$$ER_{avg} = \frac{0.06 Q_{pg} HHV_{pg} + 0.35 Q_{ng} HHV_{ng}}{Q_{pg} HHV_{pg} + Q_{ng} HHV_{ng}} \qquad \text{(Eq. 3)}$$

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Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, standard cubic feet per day (scf/day);

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(iv) For each co-fired forced draft process heater, comply with the limit in either paragraph (g)(2)(iv)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 4 of this section:

$$ER_{NOx} = \frac{0.11 Q_{oil} HHV_{oil} + 0.40 Q_{gas} HHV_{gas}}{Q_{gas} HHV_{gas} + Q_{oil} HHV_{oil}} \quad \text{(Eq. 4)}$$

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Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, scf/day;

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(h) [Reserved]

(i) For a process heater that meets any of the criteria of paragraphs (i)(1)(i) through (iv) of this section, an owner or operator may request approval from the Administrator for a NO_X emissions limit which shall apply specifically to that affected facility. The request shall include information as described in paragraph (i)(2) of this section. The request shall be submitted and followed as described in paragraph (i)(3) of this section.

(1) A process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may apply for a site-specific NO_X emissions limit:

(i) A modified or reconstructed process heater that lacks sufficient space to accommodate installation and proper operation of combustion modification-based technology (e.g., ultra-low NO_X burners); or

(ii) A modified or reconstructed process heater that has downwardly firing induced draft burners; or

(iii) A co-fired process heater; or

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(iv) A process heater operating at reduced firing conditions for an extended period of time (*i.e.*, operating in turndown mode). The site-specific NO_X emissions limit will only apply for those operating conditions.

(2) The request shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the process heater is unable to comply with the applicable NO_X emissions limit in paragraph (g)(2) of this section. At a minimum, the request shall contain the information described in paragraphs (i)(2)(i) through (iv) of this section.

(i) The design and dimensions of the process heater, evaluation of available combustion modification-based technology, description of fuel gas and, if applicable, fuel oil characteristics, information regarding the combustion conditions (temperature, oxygen content, firing rates) and other information needed to demonstrate that the process heater meets one of the four classes of process heaters listed in paragraph (i)(1) of this section.

(ii) An explanation of how the data in paragraph (i)(2)(i) demonstrate that ultra-low NO_X burners, flue gas recirculation, control of excess air or other combustion modification-based technology (including combinations of these combustion modification-based technologies) cannot be used to meet the applicable emissions limit in paragraph (g)(2) of this section.

(iii) Results of a performance test conducted under representative conditions using the applicable methods specified in §60.104a(*i*) to demonstrate the performance of the technology the owner or operator will use to minimize NO_X emissions.

(iv) The means by which the owner or operator will document continuous compliance with the site-specific emissions limit.

(3) The request shall be submitted and followed as described in paragraphs (i)(3)(i) through (iii) of this section.

(i) The owner or operator of a process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may request approval from the Administrator within 180 days after initial startup of the process heater for a NO_X emissions limit which shall apply specifically to that affected facility.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must comply with the request as submitted until it is approved.

(iii) The request shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov*.

(4) The approval process for a request for a facility-specific NO_X emissions limit is described in paragraphs (i)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a facility-specific NO_X emissions limit request will be based on the completeness, accuracy and reasonableness of the request. Factors that the EPA will consider in reviewing the request for approval include, but are not limited to, the following:

(A) A demonstration that the process heater meets one of the four classes of process heaters outlined in paragraphs (i)(1) of this section;

(B) A description of the low-NO_X burner designs and other combustion modifications considered for reducing NO_X emissions;

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(C) The combustion modification option selected; and

(D) The operating conditions (firing rate, heater box temperature and excess oxygen concentration) at which the NO_X emission level was established.

(ii) If the request is approved by the Administrator, a facility-specific NO_X emissions limit will be established at the NO_X emission level demonstrated in the approved request.

(iii) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56466, Sep. 12, 2012]

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§60.103a Design, equipment, work practice or operational standards.

(a) Except as provided in paragraph (g) of this section, each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan no later than the date specified in paragraph (b) of this section. The flare management plan must include the information described in paragraphs (a)(1) through (7) of this section.

(1) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(2) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized. The flare minimization assessment must (at a minimum) consider the items in paragraphs (a)(2)(i) through (iv) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

(i) Elimination of process gas discharge to the flare through process operating changes or gas recovery at the source.

(ii) Reduction of the volume of process gas to the flare through process operating changes.

(iii) Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.

(iv) Minimization of sweep gas flow rates and, for flares with water seals, purge gas flow rates.

(3) A description of each affected flare containing the information in paragraphs (a)(3)(i) through (vii) of this section.

(i) A general description of the flare, including the information in paragraphs (a)(3)(i)(A) through (G) of this section.

(A) Whether it is a ground flare or elevated (including height).

(B) The type of assist system (e.g., air, steam, pressure, non-assisted).

(C) Whether it is simple or complex flare tip (e.g., staged, sequential).

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(D) Whether the flare is part of a cascaded flare system (and if so, whether the flare is primary or secondary).

(E) Whether the flare serves as a backup to another flare.

(F) Whether the flare is an emergency flare or a non-emergency flare.

(G) Whether the flare is equipped with a flare gas recovery system.

(ii) Description and simple process flow diagram showing the interconnection of the following components of the flare: flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iii) Flare design parameters, including the maximum vent gas flow rate; minimum sweep gas flow rate; minimum purge gas flow rate (if any); maximum supplemental gas flow rate; maximum pilot gas flow rate; and, if the flare is steam-assisted, minimum total steam rate.

(iv) Description and simple process flow diagram showing all gas lines (including flare, purge (if applicable), sweep, supplemental and pilot gas) that are associated with the flare. For purge, sweep, supplemental and pilot gas, identify the type of gas used. Designate which lines are exempt from sulfur, H_2S or flow monitoring and why (e.g., natural gas, inherently low sulfur, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor.

(v) For each flow rate, H_2S, sulfur content, pressure or water seal monitor identified in paragraph (a)(3)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For emergency flares, secondary flares and flares equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction:

(A) Description of the water seal, including the operating range for the liquid level.

(B) Designation of the monitoring option elected (flow and sulfur monitoring or pressure and water seal liquid level monitoring).

(vii) For flares equipped with a flare gas recovery system:

(A) A description of the flare gas recovery system, including number of compressors and capacity of each compressor.

(B) A description of the monitoring parameters used to quantify the amount of flare gas recovered.

(C) For systems with staged compressors, the maximum time period required to begin gas recovery with the secondary compressor(s), the monitoring parameters and procedures used to minimize the duration of releases during compressor staging and a justification for why the maximum time period cannot be further reduced.

(4) An evaluation of the baseline flow to the flare. The baseline flow to the flare must be determined after implementing the minimization assessment in paragraph (a)(2) of this section. Baseline flows do not include pilot gas flow or purge gas flow (*i.e.*, gas introduced after the flare's water seal) provided these gas flows remain reasonably constant (*i.e.*, separate flow monitors for these streams are not required). Separate baseline flow rates may be established for different operating conditions provided that the management plan includes:

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(i) A primary baseline flow rate that will be used as the default baseline for all conditions except those specifically delineated in the plan;

(ii) A description of each special condition for which an alternate baseline is established, including the rationale for each alternate baseline, the daily flow for each alternate baseline and the expected duration of the special conditions for each alternate baseline; and

(iii) Procedures to minimize discharges to the affected flare during each special condition described in paragraph (a)(4)(ii) of this section, unless procedures are already developed for these cases under paragraph (a)(5) through (7) of this section, as applicable.

(5) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(6) Procedures to reduce flaring in cases of fuel gas imbalance (*i.e.*, excess fuel gas for the refinery's energy needs), together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(7) For flares equipped with flare gas recovery systems, procedures to minimize the frequency and duration of outages of the flare gas recovery system and procedures to minimize the volume of gas flared during such outages, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(b) Except as provided in paragraph (g) of this section, each owner or operator required to develop and implement a written flare management plan as described in paragraph (a) of this section must submit the plan to the Administrator as described in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that the flare becomes an affected facility subject to this subpart, except for the selected minimization alternatives in paragraph (a)(2) and/or the procedures in paragraphs (a)(5) though (a)(7) of this section that cannot reasonably be implemented by that date, which the owner or operator must implement in accordance with the schedule in the flare management plan. The owner or operator of a modified flare must develop and implement the flare management plan by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(2) The owner or operator must comply with the plan as submitted by the date specified in paragraph (b)(1) of this section. The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline as described in paragraph (a)(4) of this section, installs a flare gas recovery system or is required to change flare designations and monitoring methods as described in §60.107a(g). The owner or operator must comply with the updated plan as submitted.

(3) All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov.*

(c) Except as provided in paragraphs (f) and (g) of this section, each owner or operator that operates a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each of the conditions specified in paragraphs (c)(1) through (3) of this section.

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(1) For a flare:

(i) Any time the SO_2 emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period; or

(ii) Any discharge to the flare in excess of 14,160 standard cubic meters (m^3) (500,000 standard cubic feet (scf)) above the baseline, determined in paragraph (a)(4) of this section, in any 24-hour period; or

(iii) If the monitoring alternative in §60.107a(g) is elected, any period when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in paragraph (a)(3)(vii)(C) of this section.

(2) For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in §60.102a(g)(1) if the SO_2 discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(3) For a sulfur recovery plant, each time the SO_2 emissions are more than 227 kg (500 lb) greater than the amount that would have been emitted if the SO_2 or reduced sulfur concentration was equal to the applicable emissions limit in §60.102a(f)(1) or (2) during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(d) Except as provided in paragraphs (f) and (g) of this section, a root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in paragraphs (c)(1) through (3) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (d)(1) through (5) of this section.

(1) If a single continuous discharge meets any of the conditions specified in paragraphs (c)(1) through (3) of this section for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.

(2) If a single discharge from a flare triggers a root cause analysis based on more than one of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section, a single root cause analysis and corrective action analysis may be conducted.

(3) If the discharge from a flare is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare and the procedures in paragraph (a)(5) of this section were followed, a root cause analysis and corrective action analysis is not required; however, the discharge must be recorded as described in §60.108a(c)(6) and reported as described in §60.108a(d)(5).

(4) If both the primary and secondary flare in a cascaded flare system meet any of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section in the same 24-hour period, a single root cause analysis and corrective action analysis may be conducted.

(5) Except as provided in paragraph (d)(4) of this section, if discharges occur that meet any of the conditions specified in paragraphs (c)(1) through (3) of this section for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(e) Except as provided in paragraphs (f) and (g) of this section, each owner or operator of a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall implement the corrective action(s) identified in the

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corrective action analysis conducted pursuant to paragraph (d) of this section in accordance with the applicable requirements in paragraphs (e)(1) through (3) of this section.

(1) All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in §60.108a(c)(6)(ix).

(2) For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(3) No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in §60.108a(c)(6)(x).

(f) Modified flares shall comply with the requirements of paragraphs (c) through (e) of this section by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were not affected facilities subject to subpart J of this part prior to becoming affected facilities under §60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a(a)(2) by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were affected facilities subject to subpart J of this part prior to becoming affected facilities under §60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a(a)(2) by November 13, 2012 or at startup of the modified flare, whichever is later, except that modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a (a)(2) by no later than November 11, 2015.

(g) An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare shall also submit the existing flare management plan to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov.*

(h) Each owner or operator shall not burn in any affected flare any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit.

(i) Each owner or operator of a delayed coking unit shall depressure each coke drum to 5 lb per square inch gauge (psig) or less prior to discharging the coke drum steam exhaust to the atmosphere. Until the coke drum pressure reaches 5 psig, the coke drum steam exhaust must be managed in an enclosed blowdown system and the uncondensed vapor must either be recovered (e.g., sent to the delayed coking unit fractionators) or vented to the fuel gas system, a fuel gas combustion device or a flare.

(j) *Alternative means of emission limitation.* (1) Each owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a

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reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in this section.

(2) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.

(ii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(iii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(iv) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(v) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (j)(2)(iv) of this section.

(vi) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.

(3) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(4) Approval of the application for equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) After a request for determination of equivalence is received, the Administrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(ii) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.

(iii) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h)(1) of the CAA.

(5) Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of this section. The Administrator will make an equivalence determination according to the provisions of paragraphs (j)(2) through (4) of this section.

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§60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant, flare and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in §60.102a according to the requirements of §60.8. The notification requirements of §60.8(d) apply to the initial performance test and to subsequent performance tests required by paragraph (b) of this section (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments.

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in §60.105a(b), to use bag leak detectors according to the requirements in §60.105a(c), or to use COMS according to the requirements in §60.105a(e) shall conduct a PM performance test at least once every 12 months and furnish the Administrator a written report of the results of each test.

(c) In conducting the performance tests required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods in 40 CFR part 60, Appendices A-1 through A-8 or other methods as specified in this section, except as provided in §60.8(b).

(d) The owner or operator shall determine compliance with the PM, NO_X, SO_2, and CO emissions limits in §60.102a (b) for FCCU and FCU using the following methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. 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) Method 5, 5B, or 5F of appendix A-3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU without a wet scrubber subject to the emissions limit in §63.102a(b)(1). Use Method 5 or 5B of appendix A-3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU with a wet scrubber subject to the emissions limit in §63.102a(b)(1).

(i) The PM performance test consists of 3 valid test runs; the duration of each test run must be no less than 60 minutes.

(ii) The emissions rate of PM (E_{PM}) is computed for each run using Equation 5 of this section:

$$E = \frac{c_s Q_{sd}}{K R_c} \qquad \text{[Eq. 5}$$

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Where:

E = Emission rate of PM, g/kg (lb/1,000 lb) of coke burn-off;

c_s = Concentration of total PM, grams per dry standard cubic meter (g/dscm) (gr/dscf);

Q_{sd} = Volumetric flow rate of effluent gas, dry standard cubic meters per hour (dry standard cubic feet per hour);

R_c = Coke burn-off rate, kilograms per hour (kg/hr) [lb per hour (lb/hr)] coke; and

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K = Conversion factor, 1.0 grams per gram (7,000 grains per lb).

(iii) The coke burn-off rate (R_c) is computed for each run using Equation 6 of this section:

$$R = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_1 Q_r \left(\%CO/2 + \%CO_2 + \%O_2\right) - K_3 Q_{oxy} (\%O_{oxy}) \quad \text{(Eq. 6)}$$

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Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emissions control or energy recovery system that burns auxiliary fuel, dry standard cubic meters per minute (dscm/min) [dry standard cubic feet per minute (dscf/min)];

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide (CO_2) concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis);

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)];

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)]; and

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(iv) During the performance test, the volumetric flow rate of exhaust gas from catalyst regenerator (Q_r) before any emission control or energy recovery system that burns auxiliary fuel is measured using Method 2 of appendix A-1 to part 60.

(v) For subsequent calculations of coke burn-off rates or exhaust gas flow rates, the volumetric flow rate of Q_r is calculated using average exhaust gas concentrations as measured by the monitors required in §60.105a(b)(2), if applicable, using Equation 7 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%O_{oxy}) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \quad \text{(Eq. 7)}$$

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Where:

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emission control or energy recovery system that burns auxiliary fuel, dscm/min (dscf/min);

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Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with §60.105a(h)(3), assume %CO to be zero;

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis); and

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis).

(5) Method 6, 6A, or 6C of appendix A-4 to part 60 for moisture content and for the concentration of SO_2; the duration of each test run must be no less than 4 hours. 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 or 6A of appendix A-4 to part 60.

(6) Method 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for moisture content and for the concentration of NO_X calculated as nitrogen dioxide (NO_2); the duration of each test run must be no less than 4 hours. 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 7 or 7C of appendix A-4 to part 60.

(7) Method 10, 10A, or 10B of appendix A-4 to part 60 for moisture content and for the concentration of CO. The sampling time for each run must be 60 minutes.

(8) The owner or operator shall adjust PM, NO_X, SO_2 and CO pollutant concentrations to 0-percent excess air or 0-percent O_2 using Equation 8 of this section:

$$C_{adj} = C_{meas}\left[\frac{20.9}{(20.9 - \%O_2)}\right] \qquad \text{(Eq. 8)}$$

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Where:

C_{adj} = pollutant concentration adjusted to 0-percent excess air or O_2, parts per million (ppm) or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent O_2−0.0 percent O_2 (defined O_2 correction basis), percent;

20.9 = O_2 concentration in air, percent; and

$\%O_2$ = O_2 concentration measured on a dry basis, percent.

(e) The owner or operator of a FCCU or FCU that is controlled by an electrostatic precipitator or wet scrubber and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results according to the following procedures:

(1) Reduce the parameter monitoring data to hourly averages for each test run;

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(2) Determine the hourly average operating limit for each required parameter as the average of the three test runs.

(f) The owner or operator of an FCCU or FCU that uses cyclones to comply with the PM limit in §60.102a(b)(1) and elects to comply with the COMS alternative monitoring option in §60.105a(d) shall establish a site-specific opacity operating limit according to the procedures in paragraphs (f)(1) through (3) of this section.

(1) Collect COMS data every 10 seconds during the entire period of the PM performance test and reduce the data to 6-minute averages.

(2) Determine and record the hourly average opacity from all the 6-minute averages.

(3) Compute the site-specific limit using Equation 9 of this section:

$$Opacity\ Limit = Opacity_{st} \times \left(\frac{\text{lb/1,000 lb coke burn}}{PMEmR_{st}} \right) \qquad \text{(Eq. 9)}$$

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Where:

Opacity limit = Maximum permissible 3-hour average opacity, percent, or 10 percent, whichever is greater;

$Opacity_{st}$ = Hourly average opacity measured during the source test, percent; and

$PMEmR_{st}$ = PM emission rate measured during the source test, lb/1,000 lb coke burn.

(g) The owner or operator of a FCCU or FCU that is exempt from the requirement to install and operate a CO CEMS pursuant to §60.105a(h)(3) and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results using the procedures in paragraphs (g)(1) and (2) of this section.

(1) Reduce the temperature and O_2 concentrations from the parameter monitoring systems to hourly averages for each test run.

(2) Determine the operating limit for temperature and O_2 concentrations as the average of the average temperature and O_2 concentration for the three test runs.

(h) The owner or operator shall determine compliance with the SO_2 and H_2S emissions limits for sulfur recovery plants in §§60.102a(f)(1)(i), 60.102a(f)(1)(iii), 60.102a(f)(1)(iii), 60.102a(f)(2)(i), and 60.102a(f)(2)(iii) and the reduced sulfur compounds and H_2S emissions limits for sulfur recovery plants in §60.102a(f)(1)(ii) and §60.102a(f)(2)(ii) using the following methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. 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) Method 6, 6A, or 6C of appendix A-4 to part 60 to determine the SO_2 concentration. 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 or 6A of appendix A-4 to part 60.

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(5) Method 15 or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 to determine the reduced sulfur compounds and H_2S concentrations. 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 15A of appendix A-5 to part 60.

(i) Each run consists of 16 samples taken over a minimum of 3 hours.

(ii) The owner or operator shall calculate the average H_2S concentration after correcting for moisture and O_2 as the arithmetic average of the H_2S concentration for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iii) The owner or operator shall calculate the SO_2 equivalent for each run after correcting for moisture and O_2 as the arithmetic average of the SO_2 equivalent of reduced sulfur compounds for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iv) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0-percent excess air.

(j) The owner or operator shall determine compliance with the SO_2 and NO_X emissions limits in §60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses;

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. 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) Method 6, 6A, or 6C of appendix A-4 to part 60 to determine the SO_2 concentration. 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 or 6A of appendix A-4 to part 60.

(i) The performance test consists of 3 valid test runs; the duration of each test run must be no less than 1 hour.

(ii) If a single fuel gas combustion device having a common source of fuel gas is monitored as allowed under §60.107a(a)(1)(v), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

(5) Method 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for moisture content and for the concentration of NO_X calculated as NO_2; the duration of each test run must be no less than 4 hours. 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 7 or 7C of appendix A-4 to part 60.

(6) For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in §60.107a(c)(6) or (d)(8), the owner or operator shall establish the O_2 operating limit or O_2 operating curve based on the performance test results according to the requirements in paragraph (i)(6)(i) or (ii) of this section, respectively.

(i) If a single O_2 operating limit will be used:

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(A) Conduct the performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) Determine the average O_2 concentration for each test run of a valid test.

(D) Calculate the O_2 operating limit as the average O_2 concentration of the three test runs from a valid test.

(ii) If an O_2 operating curve will be used:

(A) Conduct a performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section at a representative condition for each operating range for which different O_2 operating limits will be established. Different operating conditions may be defined as different firing rates (e.g., above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity) and/or, for co-fired process heaters, different fuel mixtures (e.g., primarily gas fired, primarily oil fired, and equally co-fired, *i.e.*, approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil). Performance tests for different operating ranges may be conducted at different times.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions (*i.e.*, when the process heater is firing at 50 percent or less of the rated heat capacity). If O_2 operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(D) Determine the average O_2 concentration for each test run of a valid test.

(E) Calculate the O_2 operating limit for each operating range as the average O_2 concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.

(F) Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O_2 operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O_2 operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.

(G) Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.

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(7) The owner or operator of a process heater complying with a NO_X limit in terms of lb/MMBtu as provided in §60.102a(g)(2)(i)(B), (g)(2)(ii)(B), (g)(2)(iii)(B) or (g)(2)(iv)(B) or a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that elects to demonstrate continuous compliance with a maximum excess O_2 limit, as provided in §60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in §60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.

(8) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0-percent excess air.

(j) The owner or operator shall determine compliance with the applicable H_2S emissions limit in §60.102a(g)(1) for a fuel gas combustion device or the concentration requirement in §60.103a(h) for a flare according to the following test methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses;

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. 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) EPA Method 11, 15 or 15A of appendix A-5 to part 60 or EPA Method 16 of appendix A-6 to part 60 for determining the H_2S concentration for affected facilities using an H_2S monitor as specified in §60.107a(a)(2). The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60. The owner or operator may demonstrate compliance based on the mixture used in the fuel gas combustion device or flare or for each individual fuel gas stream used in the fuel gas combustion device or flare.

(i) For Method 11 of appendix A-5 to part 60, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

(ii) For Method 15 of appendix A-5 to part 60, at least three injects over a 1-hour period constitutes a run.

(iii) For Method 15A of appendix A-5 to part 60, a 1-hour sample constitutes a run. 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 15A of appendix A-5 to part 60.

(iv) If monitoring is conducted at a single point in a common source of fuel gas as allowed under §60.107a(a)(2)(iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device or flare is added to a common source of fuel gas that previously demonstrated compliance.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56470, Sep. 12, 2012]

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

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(a) *FCCU and FCU subject to PM emissions limit.* Each owner or operator subject to the provisions of this subpart shall monitor each FCCU and FCU subject to the PM emissions limit in §60.102a(b)(1) according to the requirements in paragraph (b), (c), (d), or (e) of this section.

(b) *Control device operating parameters.* Each owner or operator of a FCCU or FCU subject to the PM per coke burn-off emissions limit in §60.102a(b)(1) that uses a control device other than fabric filter or cyclone shall comply with the requirements in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall install, operate and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section.

(i) For units controlled using an electrostatic precipitator, the owner or operator shall use CPMS to measure and record the hourly average total power input and secondary voltage to the entire system.

(ii) For units controlled using a wet scrubber, the owner or operator shall use CPMS to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate. As an alternative to a CPMS, the owner or operator must comply with the requirements in either paragraph (b)(1)(ii)(A) or (B) of this section.

(A) As an alternative to pressure drop, the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles must conduct a daily check of the air or water pressure to the spray nozzles and record the results of each check.

(B) As an alternative to exhaust gas flow rate, the owner or operator shall comply with the approved alternative for monitoring exhaust gas flow rate in 40 CFR 63.1573(a) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

(iii) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(iv) The owner or operator shall determine and record the average coke burn-off rate and hours of operation for each FCCU or FCU using the procedures in §60.104a(d)(4)(iii).

(v) If you use a control device other than an electrostatic precipitator, wet scrubber, fabric filter, or cyclone, you may request approval to monitor parameters other than those required in paragraph (b)(1) of this section by submitting an alternative monitoring plan to the Administrator. The request must include the information in paragraphs (b)(1)(v)(A) through (E) of this section.

(A) A description of each affected facility and the parameter(s) to be monitored to determine whether the affected facility will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter (s).

(B) A description of the methods and procedures that will be used to demonstrate that the parameter(s) can be used to determine whether the affected facility will continuously comply with the emission limitations and the schedule for this demonstration. The owner or operator must certify that an operating limit will be established for the monitored parameter (s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(C) The frequency and content of the recordkeeping, recording, and reporting, if monitoring and recording are not continuous. The owner or operator also must include the rationale for the proposed monitoring, recording, and reporting requirements.

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(D) Supporting calculations.

(E) Averaging time for the alternative operating parameter.

(2) For use in determining the coke burn-off rate for an FCCU or FCU, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of CO_2, O_2 (dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels.

(i) The owner or operator shall install, operate and maintain each monitor according to Performance Specifications 3 and 4 of appendix B to part 60.

(ii) The owner or operator shall conduct performance evaluations of each CO_2, O_2 and CO monitor according to the requirements in §60.13(c) and Performance Specifications 3 and 4 of appendix B to part 60. The owner or operator shall use EPA Method 3 of appendix A-3 to part 60 and EPA Method 10, 10A or 10B of appendix A-4 to part 60 for conducting the relative accuracy evaluations.

(iii) The owner or operator shall comply with the quality assurance requirements of procedure 1 of appendix F to part 60, including quarterly accuracy determinations for CO_2 and CO monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(c) *Bag leak detection systems.* Each owner or operator shall install, operate, and maintain a bag leak detection system for each baghouse or similar fabric filter control device that is used to comply with the PM per coke burn-off emissions limit in §60.102a(b)(1) for an FCCU or FCU according to paragraph (c)(1) of this section; prepare and operate by a site-specific monitoring plan according to paragraph (c)(2) of this section; take action according to paragraph (c)(3) of this section; and record information according to paragraph (c)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(1)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

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(vii) The owner or operator shall install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator shall develop and submit to the Administrator for approval a site-specific monitoring plan for each baghouse and bag leak detection system. The owner or operator shall operate and maintain each baghouse and bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vii) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored;

(vi) Procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable; and

(vii) How the baghouse system will be operated and maintained, including monitoring of pressure drop across baghouse cells and frequency of visual inspections of the baghouse interior and baghouse components such as fans and dust removal and bag cleaning mechanisms.

(3) For each bag leak detection system, the owner or operator shall initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator shall alleviate the cause of the alarm within 3 hours of the alarm by taking whatever action(s) are necessary. Actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) The owner or operator shall maintain records of the information specified in paragraphs (c)(4)(i) through (iii) of this section for each bag leak detection system.

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(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(d) *Continuous emissions monitoring systems (CEMS).* An owner or operator subject to the PM concentration emission limit (in gr/dscf) in §60.102a(b)(1) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (0 percent excess air) of PM in the exhaust gases prior to release to the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each PM monitor according to Performance Specification 11 of appendix B to part 60. The span value of this PM monitor is 0.08 gr/dscf PM.

(2) The owner or operator shall conduct performance evaluations of each PM monitor according to the requirements in §60.13(c) and Performance Specification 11 of appendix B to part 60. The owner or operator shall use EPA Methods 5 or 5I of appendix A-3 to part 60 or Method 17 of appendix A-6 to part 60 for conducting the relative accuracy evaluations.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used 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.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 2 of appendix B to part 60 for each PM CEMS and Procedure 1 of appendix F to part 60 for each O_2 monitor, including quarterly accuracy determinations for each PM monitor, annual accuracy determinations for each O_2 monitor, and daily calibration drift tests.

(e) *Alternative monitoring option for FCCU and FCU—COMS.* Each owner or operator of an FCCU or FCU that uses cyclones to comply with the PM emission limit in §60.102a(b)(1) shall monitor the opacity of emissions according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The owner or operator shall install, operate, and maintain an instrument for continuously monitoring and recording the opacity of emissions from the FCCU or the FCU exhaust vent.

(2) The owner or operator shall install, operate, and maintain each COMS according to Performance Specification 1 of appendix B to part 60. The instrument shall be spanned at 20 to 60 percent opacity.

(3) The owner or operator shall conduct performance evaluations of each COMS according to §60.13(c) and Performance Specification 1 of appendix B to part 60.

(f) *FCCU and FCU subject to NO_X limit.* Each owner or operator subject to the NO_X emissions limit in §60.102a(b)(2) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_X emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

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(1) The owner or operator shall install, operate, and maintain each NO_X monitor according to Performance Specification 2 of appendix B to part 60. The span value of this NO_X monitor is 200 ppmv NO_X.

(2) The owner or operator shall conduct performance evaluations of each NO_X 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 Methods 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 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 7 or 7C of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used 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.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 1 of appendix F to part 60 for each NO_X and O_2 monitor, including quarterly accuracy determinations for NO_X monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(g) *FCCU and FCU subject to SO_2 limit.* The owner or operator subject to the SO_2 emissions limit in §60.102a(b)(3) for an FCCU or an FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, corrected to 0 percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each SO_2 monitor according to Performance Specification 2 of appendix B to part 60. The span value of this SO_2 monitor is 200 ppmv SO_2.

(2) 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 Methods 6, 6A, or 6C of appendix A-4 to part 60 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 6 or 6A of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used 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.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each SO_2 and O_2 monitor, including quarterly accuracy determinations for SO_2 monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

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(h) *FCCU and fluid coking units subject to CO emissions limit.* Except as specified in paragraph (h)(3) of this section, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere from each FCCU and FCU subject to the CO emissions limit in §60.102a(b)(4).

(1) The owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to part 60. The span value for this instrument is 1,000 ppm CO.

(2) The owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in §60.13(c) and Performance Specification 4 or 4A of appendix B to part 60. The owner or operator shall use Methods 10, 10A, or 10B of appendix A-4 to part 60 for conducting the relative accuracy evaluations.

(3) A CO CEMS need not be installed if the owner or operator demonstrates that all hourly average CO emissions are and will remain less than 50 ppmv (dry basis) corrected to 0 percent excess air. The Administrator may revoke this exemption from monitoring upon a determination that CO emissions on an hourly average basis have exceeded 50 ppmv (dry basis) corrected to 0 percent excess air, in which case a CO CEMS shall be installed within 180 days.

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 or 4A of appendix B to part 60. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 of appendix A-4 to part 60 and employ the sample conditioning system of Method 10A of appendix A-4 to part 60, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 of appendix B to part 60 may be used in place of the relative accuracy test.

(ii) The owner or operator must submit the following information to the Administrator:

(A) The measurement data specified in paragraph (h)(3)(i) of this section along with all other operating data known to affect CO emissions; and

(B) Descriptions of the CPMS for exhaust gas temperature and O_2 monitor required in paragraph (h)(4) of this section and operating limits for those parameters to ensure combustion conditions remain similar to those that exist during the demonstration period.

(iii) The effective date of the exemption from installation and operation of a CO CEMS is the date of submission of the information and data required in paragraph (h)(3)(ii) of this section.

(4) The owner or operator of a FCCU or FCU that is exempted from the requirement to install and operate a CO CEMS in paragraph (h)(3) of this section shall install, operate, calibrate, and maintain CPMS to measure and record the operating parameters in paragraph (h)(4)(i) or (ii) of this section. The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications.

(i) For a FCCU or FCU with no post-combustion control device, the temperature and O_2 concentration of the exhaust gas stream exiting the unit.

(ii) For a FCCU or FCU with a post-combustion control device, the temperature and O_2 concentration of the exhaust gas stream exiting the control device.

(i) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for a FCCU or FCU subject to the emissions limitations in §60.102a(b) are defined as specified in paragraphs (i)(1) through (6) of this section. Note: Determine all averages, except for opacity, as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

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(1) If a CPMS is used according to §60.105a(b)(1), all 3-hour periods during which the average PM control device operating characteristics, as measured by the continuous monitoring systems under §60.105a(b)(1), fall below the levels established during the performance test.

(2) If a PM CEMS is used according to §60.105a(d), all 7-day periods during which the average PM emission rate, as measured by the continuous PM monitoring system under §60.105a(d) exceeds 0.040 gr/dscf corrected to 0 percent excess air for a modified or reconstructed FCCU, 0.020 gr/dscf corrected to 0 percent excess air for a newly constructed FCCU, or 0.040 gr/dscf for an affected fluid coking unit.

(3) If a COMS is used according to §60.105a(e), all 3-hour periods during which the average opacity, as measured by the COMS under §60.105a(e), exceeds the site-specific limit established during the most recent performance test.

(4) All rolling 7-day periods during which the average concentration of NO_X as measured by the NO_X CEMS under §60.105a(f) exceeds 80 ppmv for an affected FCCU or FCU.

(5) All rolling 7-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS under §60.105a(g) exceeds 50 ppmv, and all rolling 365-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS exceeds 25 ppmv.

(6) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under §1A60.105a(h) exceeds 500 ppmv or, if applicable, all 1-hour periods during which the average temperature and O_2 concentration as measured by the continuous monitoring systems under §60.105a(h)(4) fall below the operating limits established during the performance test.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56473, Sep. 12, 2012]

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

(a) The owner or operator of a sulfur recovery plant that is subject to the emissions limits in §60.102a(f)(1) or §60.102a(f)(2) shall:

(1) For sulfur recovery plants subject to the SO_2 emission limit in §60.102a(f)(1)(i) or §60.102a(f)(2)(i), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are two times the applicable SO_2 emission limit and between 10 and 25 percent O_2, inclusive.

(ii) The owner or operator shall install, operate, and maintain each SO_2 CEMS according to Performance Specification 2 of appendix B to part 60.

(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 Methods 6 or 6C of appendix A-4 to part 60 and Method 3 or 3A of appendix A-2 of part 60 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 6.

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(2) For sulfur recovery plants that are subject to the reduced sulfur compound and H_2S emission limit in §60.102a(f)(1)(ii) or §60.102a(f)(2)(ii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur, H_2S, and O_2 emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span values for this monitor are two times the applicable reduced sulfur emission limit, two times the H_2S emission limit, and between 10 and 25 percent O_2, inclusive.

(ii) The owner or operator shall install, operate, and maintain each reduced sulfur CEMS according to Performance Specification 5 of appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 15 or 15A of appendix A-5 to part 60 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 15A of appendix A-5 to part 60.

(iv) The owner or operator shall install, operate, and maintain each H_2S CEMS according to Performance Specification 7 of appendix B to part 60.

(v) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 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 15A of appendix A-5 to part 60.

(vi) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60.

(vii) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(viii) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 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.

(ix) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(3) In place of the reduced sulfur monitor required in paragraph (a)(2) of this section, the owner or operator shall install, calibrate, operate, and maintain an instrument using an air or O_2 dilution and oxidation system to convert any reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of the total resultant SO_2. The monitor must include an O_2 monitor for correcting the data for excess O_2.

(i) The span value for this monitor is two times the applicable SO_2 emission limit.

(ii) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 15 or 15A of appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-

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1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60.

(iv) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(v) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 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.

(vi) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including quarterly accuracy determinations for each SO_2 monitor, annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(b) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for sulfur recovery plants subject to the emissions limitations in §60.102a(f) are defined as specified in paragraphs (b)(1) through (3) of this section.

NOTE: Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 12-hour average as the arithmetic average of 12 contiguous 1-hour averages.

(1) All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds the applicable emission limit (dry basis, zero percent excess air); or

(2) All 12-hour periods during which the average concentration of reduced sulfur (as SO_2) as measured by the reduced sulfur continuous monitoring system required under paragraph (a)(2) of this section exceeds the applicable emission limit; or

(3) All 12-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds the applicable emission limit (dry basis, 0 percent excess air).

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§60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.

(a) *Fuel gas combustion devices subject to* SO_2 or H_2S *limit and flares subject to* H_2S *concentration requirements.* The owner or operator of a fuel gas combustion device that is subject to §60.102a(g)(1) and elects to comply with the SO_2 emission limits in §60.102a(g)(1)(i) shall comply with the requirements in paragraph (a)(1) of this section. The owner or operator of a fuel gas combustion device that is subject to §60.102a(g)(1) and elects to comply with the H_2S concentration limits in §60.102a(g)(1)(ii) or a flare that is subject to the H_2S concentration requirement in §60.103a(h) shall comply with paragraph (a)(2) of this section.

(1) The owner or operator of a fuel gas combustion device that elects to comply with the SO_2 emissions limits in §60.102a(g)(1)(i) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the

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concentration (dry basis, 0-percent excess air) of SO_2 emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

(i) The owner or operator shall install, operate, and maintain each SO_2 monitor according to Performance Specification 2 of appendix B to part 60. The span value for the SO_2 monitor is 50 ppm SO_2.

(ii) The owner or operator shall conduct performance evaluations for the SO_2 monitor according to the requirements of §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of appendix A-4 to part 60 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 6 or 6A of appendix A-4 to part 60. Samples taken by Method 6 of appendix A-4 to part 60 shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(iv) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 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.

(v) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60, including quarterly accuracy determinations for SO_2 monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(vi) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO_2 emissions into the atmosphere from each of the combustion devices.

(2) The owner or operator of a fuel gas combustion device that elects to comply with the H_2S concentration limits in §60.102a(g)(1)(ii) or a flare that is subject to the H_2S concentration requirement in §60.103a(h) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel gas combustion device or flare.

(i) The owner or operator shall install, operate and maintain each H_2S monitor according to Performance Specification 7 of appendix B to part 60. The span value for this instrument is 300 ppmv H_2S.

(ii) The owner or operator shall conduct performance evaluations for each H_2S monitor according to the requirements of §60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 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 15A of appendix A-5 to part 60.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each H_2S monitor.

(iv) Fuel gas combustion devices or flares having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned in the respective fuel gas combustion devices or flares.

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(v) The owner or operator of a flare subject to §60.103a(c) through (e) may use the instrument required in paragraph (e)(1) of this section to demonstrate compliance with the H_2S concentration requirement in §60.103a(h) if the owner or operator complies with the requirements of paragraph (e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in paragraph (e)(1) of this section is used to demonstrate compliance with the H_2S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in §60.103a(h).

(vi) The owner or operator of modified flare that meets all three criteria in paragraphs (a)(2)(vi)(A) through (C) of this section shall comply with the requirements of paragraphs (a)(2)(i) through (v) of this section no later than November 11, 2015. The owner or operator shall comply with the approved alternative monitoring plan or plans pursuant to §60.13(i) until the flare is in compliance with requirements of paragraphs (a)(2)(i) through (v) of this section.

(A) The flare was an affected facility subject to subpart J of this part prior to becoming an affected facility under §60.100a.

(B) The owner or operator had an approved alternative monitoring plan or plans pursuant to §60.13(i) for all fuel gases combusted in the flare.

(C) The flare did not have in place on or before September 12, 2012 an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases that is capable of complying with the requirements of paragraphs (a)(2)(i) through (v) of this section.

(3) The owner or operator of a fuel gas combustion device or flare is not required to comply with paragraph (a)(1) or (2) of this section for fuel gas streams that are exempt under §§60.102a(g)(1)(iii) or 60.103a(h) or, for fuel gas streams combusted in a process heater, other fuel gas combustion device or flare that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(3)(i) through (iv) of this section will be considered inherently low in sulfur content.

(i) Pilot gas for heaters and flares.

(ii) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(iii) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, catalytic reforming unit, isomerization unit, and HF alkylation process units.

(iv) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(4) If the composition of an exempt fuel gas stream changes, the owner or operator must follow the procedures in paragraph (b)(3) of this section.

(b) *Exemption from H_2S monitoring requirements for low-sulfur fuel gas streams.* The owner or operator of a fuel gas combustion device or flare may apply for an exemption from the H_2S monitoring requirements in paragraph (a)(2) of this section for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the monitoring requirements of paragraphs (a)(1) and (2) of this section until there are changes in operating conditions or stream composition.

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(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high H_2S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppm H_2S. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377-86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes," 1986 Revision (incorporated by reference—see §60.17), with ranges 0-10/0-100 ppm (N = 10/1) to test the applicant fuel gas stream for H_2S; and

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare (e.g., the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out and, therefore, should be representative of typical operating conditions affecting H_2S content in the fuel gas stream going to the loading rack flare).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section.

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an H_2S test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H_2S monitoring using daily stain sampling to demonstrate compliance. The owner or operator must begin monitoring according to the requirements in paragraphs (a)(1) or (a)(2) of this section as soon as practicable, but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour H_2S concentration limit. The owner or operator of a fuel gas combustion device must also determine a rolling 365-day average using the stain sampling results; an average H_2S concentration of 5 ppmv must be used for days within the rolling 365-day period prior to the operation change.

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(c) *Process heaters complying with the NO_X concentration-based limit.* The owner or operator of a process heater subject to the NO_X emissions limit in §60.102a(g)(2) and electing to comply with the applicable emissions limit in §60.102a (g)(2)(i)(A), (g)(2)(ii)(A), (g)(2)(iii)(A) or (g)(2)(iv)(A) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere according to the requirements in paragraphs (c)(1) through (5) of this section, except as provided in paragraph (c)(6) of this section. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) Except as provided in paragraph (c)(6) of this section, the owner or operator shall install, operate and maintain each NO_X monitor according to Performance Specification 2 of appendix B to part 60. The span value of this NO_X monitor must be between 2 and 3 times the applicable emissions limit, inclusive.

(2) The owner or operator shall conduct performance evaluations of each NO_X 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 Methods 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 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 7 or 7C of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used 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.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each NO_X and O_2 monitor, including quarterly accuracy determinations for NO_X monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(6) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification-based technology to reduce NO_X emissions (*i.e.*, low-NO_X burners, ultra-low-NO_X burners) may elect to comply with the monitoring requirements in paragraphs (c)(1) through (5) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in §60.104a(i), establish a maximum excess O_2 operating limit or operating curve according to the requirements in §60.104a(i)(6) and comply with the O_2 monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O_2 operating curve is used (*i.e.*, if different O_2 operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(d) *Process heaters complying with the NO_X heating value-based or mass-based limit.* The owner or operator of a process heater subject to the NO_X emissions limit in §60.102a(g)(2) and electing to comply with the applicable emissions limit in §60.102a(g)(2)(i)(B) or (g)(2)(ii)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in paragraphs (d)(1) through (4) of this section. The owner or operator of a co-fired process heater subject to the NO_X emissions limit in §60.102a(g)(2) and electing to comply with the heating value-based limit in §60.102a(g)(2)(iii) (B) or (g)(2)(iv)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere according to the monitoring

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requirements in paragraph (d)(1) of this section; install, operate, calibrate and maintain an instrument for continuously monitoring and recording the flow rate of the fuel gas and fuel oil fed to the process heater according to the monitoring requirements in paragraph (d)(5) and (6) of this section; for fuel gas streams, determine gas composition according to the requirements in paragraph (d)(4) of this section or the higher heating value according to the requirements in paragraph (d)(7) of this section; and for fuel oil streams, determine the heating value according to the monitoring requirements in paragraph (d)(7) of this section.

(1) Except as provided in paragraph (d)(8) of this section, the owner or operator shall install, operate and maintain each NO_X monitor according to the requirements in paragraphs (c)(1) through (5) of this section. The monitor must include an O_2 monitor for correcting the data for excess air.

(2) Except as provided in paragraph (d)(3) of this section, the owner or operator shall sample and analyze each fuel stream fed to the process heater using the methods and equations in section 12.3.2 of EPA Method 19 of appendix A-7 to part 60 to determine the F factor on a dry basis. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

(3) As an alternative to the requirements in paragraph (d)(2) of this section, the owner or operator of a gas-fired process heater shall install, operate and maintain a gas composition analyzer and determine the average F factor of the fuel gas using the factors in Table 1 of this subpart and Equation 10 of this section. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

$$F_d = \frac{1{,}000{,}000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)} \qquad \text{(Eq. 10}$$

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Where:

F_d = F factor on dry basis at 0-percent excess air, dscf/MMBtu.

X_i = mole or volume fraction of each component in the fuel gas.

MEV_i = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).

MHC_i = molar heat content, Btu per mole (Btu/mol).

1,000,000 = unit conversion, Btu per MMBtu.

(4) The owner or operator shall conduct performance evaluations of each compositional monitor according to the requirements in Performance Specification 9 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 18 of appendix A-6 to part 60;

(ii) ASTM D1945-03 (Reapproved 2010)(incorporated by reference-see §60.17);

(iii) ASTM D1946-90 (Reapproved 2006)(incorporated by reference-see §60.17);

(iv) ASTM D6420-99 (Reapproved 2004)(incorporated by reference-see §60.17);

(v) GPA 2261-00 (incorporated by reference-see §60.17); or

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(vi) ASTM UOP539-97 (incorporated by reference-see §60.17).

(5) The owner or operator shall install, operate and maintain fuel gas flow monitors according to the manufacturer's recommendations. For volumetric flow meters, temperature and pressure monitors must be installed in conjunction with the flow meter or in a representative location to correct the measured flow to standard conditions (*i.e.*, 68 °F and 1 atmosphere). For mass flow meters, use gas compositions determined according to paragraph (d)(4) of this section to determine the average molecular weight of the fuel gas and convert the mass flow to a volumetric flow at standard conditions (*i.e.*, 68 °F and 1 atmosphere). The owner or operator shall conduct performance evaluations of each fuel gas flow monitor according to the requirements in §60.13 and Performance Specification 6 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 2, 2A, 2B, 2C or 2D of Appendix A-2 to part 60;

(ii) ASME MFC-3M-2004 (incorporated by reference-see §60.17);

(iii) ANSI/ASME MFC-4M-1986 (Reaffirmed 2008) (incorporated by reference-see §60.17);

(iv) ASME MFC-6M-1998 (Reaffirmed 2005) (incorporated by reference-see §60.17);

(v) ASME/ANSI MFC-7M-1987 (Reaffirmed 2006) (incorporated by reference-see §60.17);

(vi) ASME MFC-11M-2006 (incorporated by reference-see §60.17);

(vii) ASME MFC-14M-2003 (incorporated by reference-see §60.17);

(viii) ASME MFC-18M-2001 (incorporated by reference-see §60.17);

(ix) AGA Report No. 3, Part 1 (incorporated by reference-see §60.17);

(x) AGA Report No. 3, Part 2 (incorporated by reference-see §60.17);

(xi) AGA Report No. 11 (incorporated by reference-see §60.17);

(xii) AGA Report No. 7 (incorporated by reference-see §60.17); and

(xiii) API Manual of Petroleum Measurement Standards, Chapter 22, Section 2 (incorporated by reference-see §60.17).

(6) The owner or operator shall install, operate and maintain each fuel oil flow monitor according to the manufacturer's recommendations. The owner or operator shall conduct performance evaluations of each fuel oil flow monitor according to the requirements in §60.13 and Performance Specification 6 of Appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) Any one of the methods listed in paragraph (d)(5) of this section that are applicable to fuel oil (*i.e.*, "fluids");

(ii) ANSI/ASME-MFC-5M-1985 (Reaffirmed 2006) (incorporated by reference-see §60.17);

(iii) ASME/ANSI MFC-9M-1988 (Reaffirmed 2006) (incorporated by reference-see §60.17);

(iv) ASME MFC-16-2007 (incorporated by reference-see §60.17);

(v) ASME MFC-22-2007 (incorporated by reference-see §60.17); or

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(vi) ISO 8316 (incorporated by reference-see §60.17).

(7) The owner or operator shall determine the higher heating value of each fuel fed to the process heater using any of the applicable methods included in paragraphs (d)(7)(i) through (ix) of this section. If a common fuel supply system provides fuel gas or fuel oil to several process heaters, the higher heating value of the fuel in each fuel supply system may be determined at a single location in the fuel supply system provided it is representative of the fuel fed to the affected process heater(s). The higher heating value of each fuel fed to the process heater must be determined no less frequently than once per day except as provided in paragraph (d)(7)(x) of this section.

(i) ASTM D240-02 (Reapproved 2007) (incorporated by reference-see §60.17).

(ii) ASTM D1826-94 (Reapproved 2003) (incorporated by reference-see §60.17).

(iii) ASTM D1945-03 (Reapproved 2010) (incorporated by reference-see §60.17).

(iv) ASTM D1946-90 (Reapproved 2006) (incorporated by reference-see §60.17).

(v) ASTM D3588-98 (Reapproved 2003) (incorporated by reference-see §60.17).

(vi) ASTM D4809-06 (incorporated by reference-see §60.17).

(vii) ASTM D4891-89 (Reapproved 2006) (incorporated by reference-see §60.17).

(viii) GPA 2172-09 (incorporated by reference-see §60.17).

(ix) Any of the methods specified in section 2.2.7 of Appendix D to part 75.

(x) If the fuel oil supplied to the affected co-fired process heater originates from a single storage tank, the owner or operator may elect to use the storage tank sampling method in section 2.2.4.2 of Appendix D to part 75 instead of daily sampling, except that the most recent value for heating content must be used.

(8) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification based technology to reduce NO_X emissions (*i.e.*, low-NO_X burners or ultra-low NO_X burners) may elect to comply with the monitoring requirements in paragraphs (d)(1) through (7) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in §60.104a(i), establish a maximum excess O_2 operating limit or operating curve according to the requirements in §60.104a(i)(6) and comply with the O_2 monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O_2 operating curve is used (*i.e.*, if different O_2 operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(e) *Sulfur monitoring for assessing root cause analysis threshold for affected flares.* Except as described in paragraphs (e)(4) and (h) of this section, the owner or operator of an affected flare subject to §60.103a(c) through (e) shall determine the total reduced sulfur concentration for each gas line directed to the affected flare in accordance with either paragraph (e)(1), (e)(2) or (e)(3) of this section. Different options may be elected for different gas lines. If a monitoring system is in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section upon startup of the modified flare. If a monitoring system is not in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of

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a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) *Total reduced sulfur monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare.

(i) The owner or operator shall install, operate and maintain each total reduced sulfur monitor according to Performance Specification 5 of Appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (e.g., roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(ii) The owner or operator shall conduct performance evaluations of each total reduced sulfur monitor according to the requirements in §60.13(c) and Performance Specification 5 of Appendix B to part 60. For flares that routinely have flow, the owner or operator of each total reduced sulfur monitor shall use EPA Method 15A of Appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference-see §60.17) is an acceptable alternative to EPA Method 15A of Appendix A-5 to part 60. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations. For flares that do not receive routine flow, the alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each total reduced sulfur monitor.

(2) *H_2S monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of H_2S in gas discharged to the flare according to the requirements in paragraphs (e)(2)(i) through (iii) of this section and shall collect and analyze samples of the gas and calculate total sulfur concentrations as specified in paragraphs (e)(2)(iv) through (ix) of this section.

(i) The owner or operator shall install, operate and maintain each H_2S monitor according to Performance Specification 7 of Appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (e.g., roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range H_2S monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(ii) The owner or operator shall conduct performance evaluations of each H_2S monitor according to the requirements in §60.13(c) and Performance Specification 7 of Appendix B to part 60. For flares that routinely have flow, the owner or operator shall use EPA Method 11, 15 or 15A of Appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of Appendix A-5 to part 60. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations. For flares that do not receive routine flow, the alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each H_2S monitor.

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(iv) In the first 10 operating days after the date the flare must begin to comply with §60.103a(c)(1), the owner or operator shall collect representative daily samples of the gas discharged to the flare. The samples may be grab samples or integrated samples. The owner or operator shall take subsequent representative daily samples at least once per week or as required in paragraph (e)(2)(ix) of this section.

(v) The owner or operator shall analyze each daily sample for total sulfur using either EPA Method 15A of Appendix A-5 to part 60, EPA Method 16A of Appendix A-6 to part 60, ASTM Method D4468-85 (Reapproved 2006) (incorporated by reference—see §60.17) or ASTM Method D5504-08 (incorporated by reference—see §60.17).

(vi) The owner or operator shall develop a 10-day average total sulfur-to-H_2S ratio and 95-percent confidence interval as follows:

(A) Calculate the ratio of the total sulfur concentration to the H_2S concentration for each day during which samples are collected.

(B) Determine the 10-day average total sulfur-to-H_2S ratio as the arithmetic average of the daily ratios calculated in paragraph (e)(2)(vi)(A) of this section.

(C) Determine the acceptable range for subsequent weekly samples based on the 95-percent confidence interval for the distribution of daily ratios based on the 10 individual daily ratios using Equation 11 of this section.

$$AR = Ratio_{Avg} \pm 2.262 \times SDev \qquad \text{(Eq. 11)}$$

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Where:

AR = Acceptable range of subsequent ratio determinations, unitless.

$Ratio_{Avg}$ = 10-day average total sulfur-to-H_2S concentration ratio, unitless.

2.262 = t-distribution statistic for 95-percent 2-sided confidence interval for 10 samples (9 degrees of freedom).

SDev = Standard deviation of the 10 daily average total sulfur-to-H_2S concentration ratios used to develop the 10-day average total sulfur-to-H_2S concentration ratio, unitless.

(vii) For each day during the period when data are being collected to develop a 10-day average, the owner or operator shall estimate the total sulfur concentration using the measured total sulfur concentration measured for that day.

(viii) For all days other than those during which data are being collected to develop a 10-day average, the owner or operator shall multiply the most recent 10-day average total sulfur-to-H_2S ratio by the daily average H_2S concentrations obtained using the monitor as required by paragraph (e)(2)(i) through (iii) of this section to estimate total sulfur concentrations.

(ix) If the total sulfur-to-H_2S ratio for a subsequent weekly sample is outside the acceptable range for the most recent distribution of daily ratios, the owner or operator shall develop a new 10-day average ratio and acceptable range based on data for the outlying weekly sample plus data collected over the following 9 operating days.

(3) *SO_2 monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of SO_2 from a process heater or other fuel gas combustion device that is combusting gas representative of the fuel gas in the flare gas line according to the requirements in paragraph (a)(1) of this section, determine the F factor of the fuel gas at least daily according to the requirements in paragraphs (d)(2) through (4) of this section, determine the higher heating value of the fuel gas at least daily according to the requirements

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in paragraph (d)(7) of this section and calculate the total sulfur content (as SO_2) in the fuel gas using Equation 12 of this section.

$$TS_{FG} = C_{SO2} \times F_d \times HHV_{FG} \quad \text{(Eq. 12)}$$

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Where:

TS_{FG} = Total sulfur concentration, as SO_2, in the fuel gas, ppmv.

C_{SO2} = Concentration of SO_2 in the exhaust gas, ppmv (dry basis at 0-percent excess air).

F_d = F factor gas on dry basis at 0-percent excess air, dscf/MMBtu.

HHV_{FG} = Higher heating value of the fuel gas, MMBtu/scf.

(4) *Exemptions from sulfur monitoring requirements.* Flares identified in paragraphs (e)(4)(i) through (iv) of this section are exempt from the requirements in paragraphs (e)(1) through (3) of this section. For each such flare, except as provided in paragraph (e)(4)(iv), engineering calculations shall be used to calculate the SO_2 emissions in the event of a discharge that may trigger a root cause analysis under §60.103a(c)(1).

(i) Flares that can only receive:

(A) Fuel gas streams that are inherently low in sulfur content as described in paragraph (a)(3)(i) through (iv) of this section; and/or

(B) Fuel gas streams that are inherently low in sulfur content for which the owner or operator has applied for an exemption from the H_2S monitoring requirements as described in paragraph (b) of this section.

(ii) Emergency flares, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iii) Flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iv) Secondary flares that receive gas diverted from the primary flare. In the event of a discharge from the secondary flare, the sulfur content measured by the sulfur monitor on the primary flare should be used to calculate SO_2 emissions, regardless of whether or not the monitoring alternative in paragraph (g) of this section is selected for the secondary flare.

(f) *Flow monitoring for flares.* Except as provided in paragraphs (f)(2) and (h) of this section, the owner or operator of an affected flare subject to §60.103a(c) through (e) shall install, operate, calibrate and maintain, in accordance with the specifications in paragraph (f)(1) of this section, a CPMS to measure and record the flow rate of gas discharged to the flare. If a flow monitor is not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(i) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

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(ii) Use a flow sensor with a measurement sensitivity of no more than 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater.

(iii) Use a flow monitor that is maintainable online, is able to continuously correct for temperature and pressure and is able to record flow in standard conditions (as defined in §60.2) over one-minute averages.

(iv) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(v) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(2) Emergency flares, secondary flares and flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction are not required to install continuous flow monitors; provided, however, that for any such flare, the owner or operator shall comply with the monitoring alternative in paragraph (g) of this section.

(g) *Alternative monitoring for certain flares equipped with water seals.* The owner or operator of an affected flare subject to §60.103a(c) through (e) that can be classified as either an emergency flare, a secondary flare or a flare equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction may, as an alternative to the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section, install, operate, calibrate and maintain, in accordance with the requirements in paragraphs (g)(1) through (7) of this section, a CPMS to measure and record the pressure in the flare gas header between the knock-out pot and water seal and to measure and record the water seal liquid level. If the required monitoring systems are not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and locate the liquid seal level monitor in a position that provides a representative measurement of the water column height.

(2) Minimize or eliminate pulsating pressure, vibration and internal and external corrosion.

(3) Use a pressure sensor and level monitor with a minimum tolerance of 1.27 centimeters of water.

(4) Using a manometer, check pressure sensor calibration quarterly.

(5) Conduct calibration checks any time the pressure sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(6) In a cascaded flare system that employs multiple secondary flares, pressure and liquid level monitoring is required only on the first secondary flare in the system (*i.e.,* the secondary flare with the lowest pressure release set point).

(7) This alternative monitoring option may be elected only for flares with four or fewer pressure exceedances required to be reported under §60.108a(d)(5) ("reportable pressure exceedances") in any 365 consecutive calendar days. Following the fifth reportable pressure exceedance in a 365-day period, the owner or operator must comply with the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section as soon as practical, but no later than 180 days after the fifth reportable pressure exceedance in a 365-day period.

(h) *Alternative monitoring for flares located in the BAAQMD or SCAQMD.* An affected flare subject to this subpart located in the BAAQMD may elect to comply with the monitoring requirements in both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (e) and (f) of this

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section. An affected flare subject to this subpart located in the SCAQMD may elect to comply with the monitoring requirements in SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section.

(i) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in §60.102a(g) and flares subject to the concentration requirement in §60.103a(h) are defined as specified in paragraphs (i)(1) through (5) of this section. Determine a rolling 3-hour or a rolling daily average as the arithmetic average of the applicable 1-hour averages (e.g., a rolling 3-hour average is the arithmetic average of three contiguous 1-hour averages). Determine a rolling 30-day or a rolling 365-day average as the arithmetic average of the applicable daily averages (e.g., a rolling 30-day average is the arithmetic average of 30 contiguous daily averages).

(1) *SO_2 or H_2S limits for fuel gas combustion devices.* (i) If the owner or operator of a fuel gas combustion device elects to comply with the SO_2 emission limits in §60.102a(g)(1)(i), each rolling 3-hour period during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds 20 ppmv, and each rolling 365-day period during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds 8 ppmv.

(ii) If the owner or operator of a fuel gas combustion device elects to comply with the H_2S concentration limits in §60.102a(g)(1)(ii), each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H_2S continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.

(iii) If the owner or operator of a fuel gas combustion device becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H_2S exceeds 162 ppmv and each rolling 365-day period during which the average concentration of H_2S exceeds 60 ppmv.

(2) H_2S concentration limits for flares. (i) Each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv.

(ii) If the owner or operator of a flare becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H_2S exceeds 162 ppmv.

(3) *Rolling 30-day average NO_X limits for fuel gas combustion devices.* Each rolling 30-day period during which the average concentration of NO_X as measured by the NO_X continuous monitoring system required under paragraph (c) or (d) of this section exceeds:

(i) For a natural draft process heater, 40 ppmv and, if monitored according to §60.107a(d), 0.040 lb/MMBtu;

(ii) For a forced draft process heater, 60 ppmv and, if monitored according to §60.107a(d), 0.060 lb/MMBtu; and

(iii) For a co-fired process heater electing to comply with the NO_X limit in §60.102a(g)(2)(iii)(A) or (g)(2)(iv)(A), 150 ppmv.

(iv) The site-specific limit determined by the Administrator under §60.102a(i).

(4) *Daily NO_X limits for fuel gas combustion devices.* Each day during which the concentration of NO_X as measured by the NO_X continuous monitoring system required under paragraph (d) of this section exceeds the daily average emissions limit calculated using Equation 3 in §60.102a(g)(2)(iii)(B) or Equation 4 in §60.102a(g)(2)(iv)(B).

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(5) *Daily O_2 limits for fuel gas combustion devices.* Each day during which the concentration of O_2 as measured by the O_2 continuous monitoring system required under paragraph (c)(6) of this section exceeds the O_2 operating limit or operating curve determined during the most recent biennial performance test.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56473, Sep. 12, 2012]

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§60.108a Recordkeeping and reporting requirements.

(a) Each owner or operator subject to the emissions limitations in §60.102a shall comply with the notification, recordkeeping, and reporting requirements in §60.7 and other requirements as specified in this section.

(b) Each owner or operator subject to an emissions limitation in §60.102a shall notify the Administrator of the specific monitoring provisions of §§60.105a, 60.106a and 60.107a with which the owner or operator intends to comply. Each owner or operator of a co-fired process heater subject to an emissions limitation in §60.102a(g)(2)(iii) or (iv) shall submit to the Administrator documentation showing that the process heater meets the definition of a co-fired process heater in §60.101a. Notifications required by this paragraph shall be submitted with the notification of initial startup required by §60.7(a)(3).

(c) The owner or operator shall maintain the following records:

(1) A copy of the flare management plan.

(2) Records of information to document conformance with bag leak detection system operation and maintenance requirements in §60.105a(c).

(3) Records of bag leak detection system alarms and actions according to §60.105a(c).

(4) For each FCCU and fluid coking unit subject to the monitoring requirements in §60.105a(b)(1), records of the average coke burn-off rate and hours of operation.

(5) For each fuel gas stream to which one of the exemptions listed in §60.107a(a)(3) applies, records of the specific exemption determined to apply for each fuel stream. If the owner or operator applies for the exemption described in §60.107a(a)(3)(iv), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(6) Records of discharges greater than 500 lb SO_2 in any 24-hour period from any affected flare, discharges greater than 500 lb SO_2 in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant and discharges to an affected flare in excess of 500,000 scf above baseline in any 24-hour period as required by §60.103a(c). If the monitoring alternative provided in §60.107a(g) is selected, the owner or operator shall record any instance when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in §60.103a(a)(3)(vii)(C). The following information shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds:

(i) A description of the discharge.

(ii) The date and time the discharge was first identified and the duration of the discharge.

(iii) The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. For a flare, record the measured or calculated cumulative quantity of gas discharged to the flare over the discharge duration. If the discharge duration

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exceeds 24 hours, record the quantity of gas discharged to the flare for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices, but are not allowed for flares, except for those complying with the alternative monitoring requirements in §60.107a(g).

(iv) For each discharge greater than 500 lb SO_2 in any 24-hour period from a flare, the measured total sulfur concentration or both the measured H_2S concentration and the estimated total sulfur concentration in the fuel gas at a representative location in the flare inlet.

(v) For each discharge greater than 500 lb SO_2 in excess of the applicable short-term emissions limit in §60.102a(g)(1) from a fuel gas combustion device, either the measured concentration of H_2S in the fuel gas or the measured concentration of SO_2 in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices, but cannot be used to make these estimates for flares, except as provided in §60.107a(e)(4).

(vi) For each discharge greater than 500 lb SO_2 in excess of the allowable limits from a sulfur recovery plant, either the measured concentration of reduced sulfur or SO_2 discharged to the atmosphere.

(vii) For each discharge greater than 500 lb SO_2 in any 24-hour period from any affected flare or discharge greater than 500 lb SO_2 in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant, the cumulative quantity of H_2S and SO_2 released into the atmosphere. For releases controlled by flares, assume 99-percent conversion of reduced sulfur or total sulfur to SO_2. For fuel gas combustion devices, assume 99-percent conversion of H_2S to SO_2.

(viii) The steps that the owner or operator took to limit the emissions during the discharge.

(ix) The root cause analysis and corrective action analysis conducted as required in §60.103a(d), including an identification of the affected facility, the date and duration of the discharge, a statement noting whether the discharge resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under §60.103a(e).

(x) For any corrective action analysis for which corrective actions are required in §60.103a(e), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(xi) For each discharge from any affected flare that is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare, a statement that a root cause analysis and corrective action analysis are not necessary because the owner or operator followed the flare management plan.

(7) If the owner or operator elects to comply with §60.107a(e)(2) for a flare, records of the H_2S and total sulfur analyses of each grab or integrated sample, the calculated daily total sulfur-to-H_2S ratios, the calculated 10-day average total sulfur-to-H_2S ratios and the 95-percent confidence intervals for each 10-day average total sulfur-to-H_2S ratio.

(d) Each owner or operator subject to this subpart shall submit an excess emissions report for all periods of excess emissions according to the requirements of §60.7(c) except that the report shall contain the information specified in paragraphs (d)(1) through (7) of this section.

(1) The date that the exceedance occurred;

(2) An explanation of the exceedance;

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(3) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and

(4) A description of the action taken, if any.

(5) The information described in paragraph (c)(6) of this section for all discharges listed in paragraph (c)(6) of this section. For a flare complying with the monitoring alternative under §60.107a(g), following the fifth discharge required to be recorded under paragraph (c)(6) of this section and reported under this paragraph, the owner or operator shall include notification that monitoring systems will be installed according to §60.107a(e) and (f) within 180 days following the fifth discharge.

(6) For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(7) A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56479, Sep. 12, 2012]

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§60.109a Delegation of authority.

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a state, local or tribal agency, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the state, local or tribal agency.

(1) Approval of a major change to test methods under §60.8(b). A "major change to test method" is defined in 40 CFR 63.90.

(2) Approval of a major change to monitoring under §60.13(i). A "major change to monitoring" is defined in 40 CFR 63.90.

(3) Approval of a major change to recordkeeping/reporting under §60.7(b) through (f). A "major change to recordkeeping/reporting" is defined in 40 CFR 63.90.

(4) Approval of an application for an alternative means of emission limitation under §60.103a(j) of this subpart.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56480, Sep. 12, 2012]

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Table 1 to Subpart Ja of Part 60—Molar Exhaust Volumes and Molar Heat Content of Fuel Gas Constituents

Constituent	MEV[a] dscf/mol	MHC[b] Btu/mol
Methane (CH_4)	7.29	842

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Ethane (C_2H_6)	12.96	1,475
Hydrogen (H_2)	1.61	269
Ethene (C_2H_4)	11.34	1,335
Propane (C_3H_8)	18.62	2,100
Propene (C_3H_6)	17.02	1,947
Butane (C_4H_{10})	24.30	2,717
Butene (C_4H_8)	22.69	2,558
Inerts	0.85	0

[a]MEV = molar exhaust volume, dry standard cubic feet per gram-mole (dscf/g-mol) at standard conditions of 68 °F and 1 atmosphere.

[b]MHC = molar heat content (higher heating value basis), Btu per gram-mole (Btu/g-mol).

[77 FR 56480, Sep. 12, 2012]

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Comparison of 20.2.36 NMAC with Federal Rules

NMAC 36 Sections and Applicability	NMAC 36 Requirements	40 CFR Part 60 Subpart J and Ja Requirements
109 – Existing Petroleum Refineries	Total Sulfur emissions ≤ 5 tons in 24 hour period	No equivalent provision; however existing refineries, covered by NSPS, except for one exception* (see below)
110 – New Petroleum Refinery – more than 5 and less than 30 tons sulfur released in plant processes per day	No more than 10 lbs. sulfur emitted for every 100 lbs. of sulfur released in plant processes	Sulfur Recovery Unit SO2 ≤ 250 ppm; Fluid Catalytic Cracker SO2 ≤ 50 ppm
111 – New Petroleum Refinery - more than 30 tons sulfur released in plant processes per day	No more than 2 lbs. of sulfur emitted for every 100 lbs. of sulfur released in plant processes. (98% reduction)	
112 – New Petroleum Refinery – Sulfur Content of Fuel Gas	Amount of sulfur in the off-gas stream from fuel-gas burning equipment≤10 grains per 100 standard cubic feet of fuel gas	Equivalent requirement in Subpart J
114 – Stack Height	A stack height to prevent concentrations of sulfur compounds near ground level equal or greater than any state or federal ambient air standard	Required as part of ambient impact analysis for construction permit applications

*Subpart J and Ja apply to Claus Type Sulfur Recovery Units, Fluid Catalytic Crackers, and sulfur content of fuel gas. The Gallup refinery uses two small uncommon sulfur recovery units that are exempt from Subpart J and Ja requirements. The Gallup refinery sulfur recovery units do not have an incinerator stack and very minor or no H_2S emissions. An analysis was conducted, and overall allowable sulfur emissions for the Gallup refinery under Subpart J, Ja, and other NMED permit requirements are still much less than Part 36.

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New Mexico Environment Department
Air Quality Bureau
Compliance and Enforcement Section
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505
Phone (505) 476-4300 Fax (505) 476-4375

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NMAC 20.2.36 1Q 2014

SECTION I - GENERAL COMPANY AND FACILITY INFORMATION

A. ® Company Name: Navajo Refining Co. L.L.C.			D. ® Facility Name: Navajo Refining Co. L.L.C.		
B.1 ® Company Address: PO Box 159			E.1 ® Facility Address: 501 E. Main St.		
B.2 ® City: Artesia	B.3 ® State: NM	B.4 ® Zip: 88211-0159	E.2 ® City: Artesia	E.3 ® State: NM	E.4 ® Zip: 88210
C.1 ® Company Environmental Contact: Dan Crawford	C.2 ® Title: Environmental Manager		F.1 ® Facility Contact: Dan Crawford	F.2 ® Title: Environmental Manager	
C.3 ® Phone Number: 575-746-5487	C.4 ® Fax Number: 575-746-5451		F.3 ® Phone Number: 575-746-5487	F.4 ® Fax Number: 575-746-5451	
C.5 ® Email Address: dan.crawford@hollyfrontier.com			F.5 ® Email Address: dan.crawford@holyfrontier.com		
G. Responsible Official: (Title V only): Michael McKee	H. Title: Vice President & Refinery Manager, Navajo Refining Co. LLC		I. Phone Number: 575-748-3311	J. Fax Number: 575-746-5451	

K. ® AI Number:	L. Title V Permit Number:	M. Title V Permit Issue Date:	N. NSR Permit Number:	O. NSR Permit Issue Date:
198	P051-R1M1	02/02/2012	PSD-NM-0195-M35	05/06/2014

P. Reporting Period: From: 01/01/2014 To: 03/31/2014

SECTION II – TYPE OF SUBMITTAL (check one that applies)

A. ☐	Title V Annual Compliance Certification	Permit Condition(s):	Description:	
B. ☐	Title V Semi-annual Monitoring Report	Permit Condition(s):	Description:	
C. ☐	NSPS Requirement (40CFR60)	Regulation:	Section(s):	Description:
D. ☐	MACT Requirement (40CFR63)	Regulation:	Section(s):	Description:
E. ☒	NMAC Requirement (20.2.xx) or NESHAP Requirement (40CFR61)	Regulation: 20.2.36 NMAC	Section(s): 113	Description: Quarterly Sulfur Balance Report
F. ☐	Permit or Notice of Intent (NOI) Requirement	Permit No. ☐: or NOI No. ☐:	Condition(s):	Description:
G. ☐	Requirement of an Enforcement Action	NOV No. ☐: or SFO No. ☐: or CD No. ☐: or Other ☐:	Section(s):	Description:

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SECTION IV - CERTIFICATION

After reasonable inquiry, I Michael McKee (name of reporting official) certify that the information in this submittal is true, accurate and complete.

® Signature of Reporting Official:	® Title:	® Date	® Responsible Official for Title V?
Michael McKee	Vice President & Refinery Manager, Navajo Refining Co. LLC	05/14/2014	☒ Yes ☐ No

Reviewed By: _____ Date Reviewed: _____

NMED Exhibit 8

HOLLYFRONTIER.

May 14, 2014

Ms. Judy Fisher
Compliance & Enforcement Manager
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505-1816

Certified Mail/Return Receipt
7007 3020 0000 3028 8017

Re: 20.2.36.113 NMAC Reports for First Quarter 2014
Navajo Refining Company, L.L.C. - Artesia and Lovington Refineries

Pursuant to 20.2.36.113 NMAC, Navajo is submitting the attached reports corresponding to the period: January 1st to March 31st, 2014. The 20.2.36.113 NMAC reports were prepared using material balance methodology. This methodology uses sample data and chemical engineering material balance to account for the amount of sulfur present in our refineries. Sulfur concentrations may be adjusted from sample results as needed based on engineering judgment in order to close the material balance. Additionally, the overhead off-gas stream in the Lovington refinery is not routinely sampled due to both, sample quality problems and safety concerns. The attached reports indicate that during the reporting period:

- The Lovington refinery was in compliance with 20.2.36.109 NMAC.
- The Artesia refinery was in compliance with the applicable sulfur recovery requirements of 20.2.36.110 NMAC and 20.2.36.111 NMAC. Therefore, the Artesia refinery was also in compliance with AQB Permit 195-M34 Condition A111.

If you have any questions, please contact me at the above address or by telephone at (575) 746-5487.

Sincerely,

Dan L. Crawford, P.G.
Environmental Manager

Enclosure

Electronic cc (w/enc.) M. McKee, R. Boans, D. Drum, B. Romine, J. Hodges, E. Hita, J. Laurent, D. Crawford, G. Combs
Environmental File Sulfur Balance Reports RLF.ART.14 - 3.11.01
NMAC 20-2-36-113.2014.1 Qtr.2014-05-13 1qtr 2014-113.doc

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Navajo Refining Company, LLC 20.2.36.113 NMAC Quarterly Sulfur Balance

2014 1st Quarter Sulfur Balance 01/01/2014 to 04/01/2014						
Lovington	Raw Feed				Intermediate Products	
	Avg. Rate BPD	Avg. Density (lb/bbl)	Avg. Sulfur Wt%	Avg. Sulfur (Short Tons/Day)	Avg. Sulfur Wt%	Avg. Sulfur (Short Tons/Day)
Lovington Crude	65,630	290	0.9%	84.7		
Casinghead	24	272	0.8%	0.0		
Stab Gas						2.3
Naphtha					0.1%	3.7
Kerosene					0.4%	5.4
Diesel					0.9%	17.0
Sour Gas Oil					1.5%	25.9
Asphalt					2.7%	29.4
Totals				84.7		83.8
Purchased Fuel Gas	6.8	mscfd	0.0007%	0.0011		

Total Sulfur From Feed	84.7
Total Sulfur in Products	83.8
Percent Sulfur Recovery	98.9%

Notes:
* 1 short ton = 2,000 lbs.

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2014 1st Quarter Sulfur Balance 01/01/2014 to 04/01/2014				
Artesia	Raw Feed		Finished Products	
	Avg. Sulfur Wt%	Avg. Sulfur (Short Tons/Day)	Sulfur Wt%	Sulfur (Short Tons/Day)
Artesia Crude	1.6%	75.6		
W-58 Bottoms				
W-27 Naphtha				
W-16 Naphtha				
Kerosene				
Diesel				
AGO				
W-55 Diesel				
W-55 Gas Oil				
W-55 Bottoms				
W-62 Diesel				
W-62 Gas Oil				
Asphalt				
Casinghead feed to Units 06 or 13	0.8%	1.9		
Lovington Transfer				
Naphtha	0.1%	3.7		
Kerosene	0.4%	5.4		
Diesel	0.9%	17.1		
Gas Oil	1.5%	25.9		
Asphalt	2.7%	29.4	3.2%	17.6
Solvent Extraction				
Feed				
DAO				
Pitch			4.4%	28.5
Desulfurization				
Naphtha Splitter Bottoms			0.0%	0.0004
Diesel			0.06%	3.4
Gs Oil			0.3%	0.13
Hydrocracking (Unit 34)				
Feed				
Naphtha				
Light Diesel				
Heavy Diesel				
Gas Oil				
FCC (Unit 10)				
Feed				
LCN			0.00%	0.00
HCN				
LCO			0.0%	0.00
HCO			0.0%	0.000
Slurry			1.1%	0.70
FCC Scrubber Sulfur			--	1.37
Sulfur In Fuel Gas			0.0007%	0.001
Sulfur In Purchased/Natural Gas Feed, MMSCFD	0.0007%	0.003		
Sulfur from SRU Incinerators			0.002%	0.039
Liquid Sulfur			--	104.6
Totals		159.0		156.3

Sulfur in Sour Water Off Gas	16%			
Sulfur in feed to SRU	92%			

Total Sulfur From Feedstocks	159.0
Total Sulfur in Products	156.3
Percent Sulfur Recovery	98.3%

Notes:
* 1 short ton = 2,000 lbs.
* Any negative #'s are due to inventory delta exceeding production

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Table 1. Sulfur Emission totals for all units at facility

Source ID	Source Type	Permitted Allowable SO_2 emissions in Table 2-E[1] (lb/hr)	Permitted Allowable H_2S emissions in Table 2-E[1] (ton/year)	Total H_2S Emissions (lb/hr)	Permit Allowable Equivalent for Sulfur Emissions (lb/hr)	Permit Allowable Equivalent for Sulfur Emissions (ton/24 hr)
NSPS J Combustion Units						
Z-81-B102	Boiler	2.53			1.27	0.015
Z-81-B104	Steam Boiler (part of cogen unit)	0.82			0.41	0.005
Z-81-B105	Steam Boiler (part of cogen unit)	0.82			0.41	0.005
A-H2	Furnace	0.88			0.44	0.0053
C-H5	Furnace	1.20			0.60	0.0072
H-F1	Furnace	0.88			0.44	0.0053
H-F2	Furnace	0.58			0.29	0.0035
I-H1	Furnace	0.51			0.26	0.0031
I-H2	Furnace	0.28			0.14	0.0017
P-H1	Furnace	1.88	-	-	0.94	0.011
P-H2	Furnace	1.30			0.65	0.0078
C-H1	Furnace	2.95			1.48	0.018
C-H2	Furnace	1.17			0.59	0.0070
D-H1A	Furnace	0.28			0.14	0.0017
D-H2	Vertical/cylindrical ultra low sulfur DHT feed heater	0.26			0.13	0.0016
D-H3	Vertical/cylindrical trickle bed reactor feed heater with two Low NO_x burners	0.38			0.19	0.0023
					Total Sulfur Emissions for NSPS J Combustion Units	**0.10**
NSPS Ja Combustion Units						
FL-1	Smokeless Flare	2.10	-	-	1.1	0.01
Z-81-B106	Boiler	3.70		-	1.9	0.022
					Total Sulfur Emissions for NSPS Ja Combustion Units	**0.035**
NSPS GG Units						
Z-81-G104	Gas Turbine (part of cogen unit)	0.50	-	-	0.25	0.0030
Z-81-G105	Gas Turbine (part of cogen unit)	0.50			0.25	0.0030
					Total Sulfur Emissions for NSPS GG Units	**0.0060**
H_2S source units						
EG-1	Equipment Group 1 Tanks	-	1.8	0.41	0.39	0.0046
F	Facility Wide Fugitives		-	-	-	-
Process Vessel Blowdowns	Process Vessel Blowdown SSM Events		-	-	-	-
					Total Sulfur Emissions for H_2S source Units	**0.0046**
Remaining Sources						
G-C1A	Gas Compressor Engine	0.11			0.055	0.00066
G-C1B	Gas Compressor Engine	0.11			0.055	0.00066
G-C1C	Gas Compressor Engine	0.11			0.055	0.00066
P-C1A	Gas Compressor Engine	0.16			0.08	0.00096
P-C1B	Gas Compressor Engine	0.16			0.08	0.00096
ESP	Electrostatic Precipitator	62.3	-	-	31.15	0.37
TV-1	Sour Water Amine Ammonium Thiosulfate Solution Gas Processing Unit	0.77			0.385	0.005
AC-11	Air Compressor CI-RICE	0.98			0.49	0.0059
Diesel pump	CI-RICE	0.00072			0.00036	4.32E-06
					Total Sulfur Emissions for Remaining Sources	**0.39**
					Total Facility Sulfur Emissions	**44.5**	**0.53**
					Total Facility Sulfur Emission Requirement per 20.2.36 NMAC	**5.0**

[1] All emissions from the 2014 Title V Renewal Application

NMED Exhibit 9

Part 36 and Part 37 Feedback
12-May-14

Last name	First name	Category	Date	Comments
Aaron	Daily	City of Farmington	2-Apr	For parts 36 and 37 of 20.2 NMAC, I would vote that they be repealed, using the logic that is included in Regulatory option 1 of the attached letters requesting written responses. The federal regulations cover down on this already with their own set of recordkeeping and reporting requirements that would be incorporated into an applicable facility's air quality permit. Repealing the state regulations would potentially eliminate some additional paperwork and checklists for NMED inspectors while conducting their compliance evaluations, yet the inspectors would achieve the same result while going through the federal regulation.
Ted	Schooley	NMED-AQB	13-Apr	Question #1: Yes, Part 36 should be repealed (Option 1) because it is less stringent than NSPS Subparts J and Ja. There is no point in revising it (Option 2), because our stationary limitations on stringency will not allow us to be more stringent than J and Ja. This being the case, what is the point of updating Part 36 with a set of requirements that are a subset of the requirements in J and Ja? Part 36 has outlived its usefulness and needlessly causes confusion and added effort on both industry and regulators. Against these negatives, it offers no benefits to justify keeping it. Question #2: Yes, I am interested in participating in a work group for further analysis of this rule.
Shirley	McNall	public	21-Apr	Question 1: In both cases, Rule 20.2.36 NMAC Petroleum Refinery Sulfur Part 36 and Rule 20.2.37 Petroleum Processing Facilities Part 37, I prefer regulatory option #2 - Revise. For the health and safety of the people of New Mexico, these rules need to be revised to allow enforcement by requireing stringent monitoring and recordkeeping!
Wendy	Alexander	TRC	22-Apr	<she called asking for more info and extent of comments requested. She asked for a word version of part 36, 37, 38>

NMED Exhibit 10

John	Bartlit	New Mexico Citizens for Clean Air & Water	27-Apr-14	Thank you for your emails of April 1 regarding petroleum rules, parts 36 and 37. The information that was provided implies that the existing legal constraints on rule changes offer little room for significant improvement from anyone's perspective. Your emails explain that rules are constrained by federal law to be at least as stringent as federal regulations and constrained by state law to be no more stringent than the fed's. These legal bounds say that changes made must leave the state's rules no more and no less stringent than the fed's, which makes the possibilities for change very narrow. In view of these tight restrictions, our environmental organization, New Mexico Citizens for Clean Air & Water, cannot give significant time and energy to this project. We remain interested in receiving updates on the work's progress. Thank you for keeping us informed.
Don	Shepard	National Park Service	30-Apr	see attached
Brian	Stone	Navajo Refining Company (Artesia & Lovington)	30-Apr	see attached
Ed	Ridge	Western Refining (Gallup)	30-Apr	see attached

NMED Exhibit 10

NEW MEXICO
ENVIRONMENT DEPARTMENT

Air Quality Bureau

525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico, 87505
Phone (505) 476-4300 Fax (505) 476-4375
www.nmenv.state.nm.us

SUSANA MARTINEZ
Governor
JOHN A. SANCHEZ
Lieutenant Governor

RYAN FLYNN
Cabinet Secretary
BUTCH TONGATE
Deputy Secretary

April 1, 2014

Dear Air Quality Stakeholder,

The New Mexico Environment Department, Air Quality Bureau is currently reviewing and evaluating state rule 20.2.36 NMAC – Petroleum Refinery - Sulfur (Part 36). This regulation can be found on the New Mexico website here:
http://www.nmcpr.state.nm.us/nmac/_title20/T20C002.htm.
Part 36 establishes sulfur limits (sulfur recovery standards) and other requirements for existing (constructed prior to July 1, 1974) and new petroleum refineries. The rule was identified in the November 2012 Improving Environmental Permitting Report as a rule for potential revision or repeal. The Improving Environmental Permitting Report is on our website at http://www.nmenv.state.nm.us/aqb/permit/index.html.

This letter briefly discusses the regulatory options and includes a list of questions for the regulated industry, environmental groups, and other stakeholders. Please provide written responses to the questions by April 30, 2014. We would also like to invite you to participate in a work group to further analyze the rule.

Regulatory Option 1: Repeal 20.2.36 NMAC
The U.S. Environmental Protection Agency's (EPA) New Source Performance Standards (NSPS) for Petroleum Refineries contained in 40 CFR Part 60 Subparts J and Ja require sulfur oxides emissions reductions from several types of refinery processes equipment. Part 36 has enforceability issues due to a lack of monitoring and recordkeeping requirements. In comparison, Subparts J and Ja require continuous monitoring which makes enforcement more effective. With respect to reporting requirements, Part 36 quarterly reporting can be redundant as subject facilities are required to submit semi-annual reports required by Subparts J and Ja, and semi-annual and annual compliance reports required by Title V permits. Prior to recommending repeal of this rule, NMED must also evaluate whether the repeal of this rule would negatively affect air quality.

Regulatory Option 2: Revise 20.2.36 NMAC
Revisions would have to take into consideration statutory limitations on stringency. Standards of performance adopted by the State for petroleum refineries must be as stringent, but no more stringent, than the federal regulations at Subparts J and Ja. See NMSA 1978, § 74-2-5 (C)(2).

Regulatory Option 3: No Action
The result of no action would be that an outdated and confusing rule remains in the New Mexico Administrative Code. The issues identified in Option 1 would persist.

Questions to Stakeholders about the Rule

1. Do you have preferences on whether the rule is revised, repealed or no action is taken? Please explain.
2. Would you be interested in participating in a work group for further analysis of the rule?

After consideration of stakeholder input, we plan to recommend one of the three options.
If you would like to make comments, or be added to (or removed from) the list of persons who will be notified of activities related to this regulatory action, please contact Mark Jones at (505) 566-9746 or mark.jones@state.nm.us.

For information sharing purposes, we are also soliciting input from industry, various environmental groups and the general public.

Thank you for your interest in New Mexico's air quality.

Regards,

Mark Jones

Mark Jones
Environmental Analyst
505-566-9746
Mark.jones@state.nm.us

NEW MEXICO
ENVIRONMENT DEPARTMENT

Air Quality Bureau

525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico, 87505
Phone (505) 476-4300 Fax (505) 476-4375
www.nmenv.state.nm.us

SUSANA MARTINEZ
Governor
JOHN A. SANCHEZ
Lieutenant Governor

RYAN FLYNN
Cabinet Secretary
BUTCH TONGATE
Deputy Secretary

April 1, 2014

Dear Air Quality Stakeholder,

The New Mexico Environment Department, Air Quality Bureau is currently reviewing and evaluating state rule 20.2.36 NMAC – Petroleum Refineries (Part 36). This regulation can be found on the New Mexico website here: http://www.nmcpr.state.nm.us/nmac/_title20/T20C002.htm. Part 36 establishes sulfur limits (sulfur recovery standards) and other requirements for existing (constructed prior to July 1, 1974) and new petroleum refineries. The rule was identified in the November 2012 Improving Environmental Permitting Report as a rule for potential revision or repeal. The Improving Environmental Permitting Report is on our website at http://www.nmenv.state.nm.us/aqb/permit/index.html.

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Questions to Stakeholders about the Rule

1. Is your facility subject to Part 36? If so, are you subject to the section for existing sources (20.2.36.109 NMAC) or new refinery standards (20.2.36.110 NMAC)?
2. Are there any federal regulations or other requirements limiting sulfur emissions with which you are also required to comply? Are these requirements more, equally, or less stringent than Part 36? Please explain.
3. In general, what are your recordkeeping and reporting practices for Part 36 and for other federal sulfur emissions requirements?
4. Do you have preferences on whether the rule is revised, repealed or no action is taken? Please explain.
5. Would you be interested in participating in a work group for further analysis of the rule?

After consideration of stakeholder input, we plan to recommend one of the three options. If you would like to make comments, or be added to (or removed from) the list of persons who will be notified of activities related to this regulatory action, please contact Mark Jones at (505) 566-9746 or mark.jones@state.nm.us

For information sharing purposes, we are also soliciting input from industry, various environmental groups and the general public.

Thank you for your interest in New Mexico's air quality.

Regards,

Mark Jones

Mark Jones
Environmental Analyst
505-566-9746
Mark.jones@state.nm.us

Part 36 and Part 37 Feedback
12-May-14

Last name	First name	Category	Date	Comments
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Brian	Stone	Navajo Refining Company (Artesia & Lovington)	30-Apr	see attached
Ed	Ridge	Western Refining (Gallup)	30-Apr	see attached

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April 30, 2014

Mark Jones
Air Quality Bureau, NMED
525 Camino de Los Marquez, Suite 1
Santa Fe, NM 87505

Re: Stakeholder Comments on NMAC Part 36 and Part 37 Proposed Revisions

Dear Mr. Jones,

In response to your letters requesting stakeholder comments on proposed revisions to 20.2.36 NMAC Part 36 and 20.2.37 NMAC Part 37, I am submitting the following comments on behalf of Navajo Refining Company L. L. C. Navajo operates petroleum refineries in Artesia, NM, and Lovington, NM.

Part 36

1. Is your facility subject to Part 36? Yes.
If so, are you subject to the section for existing sources (20.2.36.109) or new refinery standards (20.2.36.110 NMAC)? Existing sources.

2. Are there any federal regulations or other requirements limiting sulfur emissions with which you are also required to comply? Yes, NSPS subparts J and Ja.
Are these requirements more, equally, or less stringent than Part 36? Please explain. The sulfur content determination and quarterly reporting requirements in 20.2.36.113 are more burdensome than those in NSPS subparts J and Ja, while being less restrictive.

3. In general, what are your recordkeeping and reporting practices for Part 36 and for other federal sulfur emissions requirements? NSPS subparts J and Ja require semi-annual reports. 20.2.36.113 requires quarterly reports. Additionally, 20.2.36.113 requires sulfur determinations on feedstocks, fuels, products, inlets and outlets to SRUs, and weights of recovered sulfur to be determined on weekly and monthly frequencies. Navajo complies with this requirement by laboratory testing, and in the cases testing is not feasible or sampling creates unacceptable safety risk, by mass balance. Proposed revision options would, assumedly, relieve Navajo of this burden.

4. Do you have preferences on whether the rule is revised, repealed or no action is taken? Please explain. Either revising the rule to incorporate NSPS J and Ja or repealing the rule is preferred by Navajo.

Navajo Refining Company, L.L.C.
501 East Main • Artesia, NM 88210
(575) 748-3311 • http://www.hollyfrontier.com

5. Would you be interested in participating in a work group for further analysis of the rule? Yes. Please contact me at the address listed below.

Part 37

1. Is your facility subject to Part 37? Yes.
If so, are you an existing or new facility under Part 37? Existing sources.

2. Are there any federal regulations or other requirements limiting mercaptan, hydrogen sulfide, carbon monoxide, particulate matter, or ammonia emissions with which you are also required to comply? Federal regulations cover hydrogen sulfide, carbon monoxide, and particulate matter.
Are these requirements more, equally, or less stringent than Part 37 (20.37.200-205 NMAC)? Please explain. Federal regulations do not cover mercaptan or ammonia. In general, Part 37 requirements are more stringent than federal regulations since Part 37 limits cover the entire facility.

3. Is your facility subject to any federal regulations or other requirements for hydrocarbon separation or blowdown systems? No.

4. In general, what are your recordkeeping and reporting practices for Part 37? Semiannual reporting and annual certification.

5. Do you have preferences on whether the rule is revised, repealed or no action taken? Please explain. Part 37 rules cover pollutants and facilities that are not covered by federal rules. Repealing Part 37, or revising Part 37 to be no more stringent than NSPS J and Ja would result in fewer petroleum processing facilities and fewer pollutant being regulated. Navajo favors retaining Part 37 as written.

6. Would you be interested in participating in a work group for further analysis of the rule? Yes. Please contact at the address listed below.

If you have any questions or concerns, please contact me by email brian.stone@hollyfrontier.com or by telephone at (575) 308-1511.

Sincerely,

BM Stone

Brian Stone, P.E
Environmental Specialist

NMED Exhibit 10

Enclosure

Electronic cc (w/enc): NMED: Mark Jones
Navajo: M. Holder, D. Crawford, B. Stone, G. Combs, R. Smalls, C. Hernandez

Environmental File: NMAC Parts 36 and 37\2014-4-30 Comments on Parts 36 and 37 rule changes

May 23, 2014

Via email: Mark.jones@state.nm.us

Mr. Mark Jones
Environmental Analyst
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

Mr. Jones,

On April 1, 2014, the New Mexico Environment Department (NMED) sent a letter to stakeholders regarding review of 20.2.36 NMAC for sulfur emissions from petroleum refineries in New Mexico. In the letter, NMED requests comments from potentially affected facilities regarding the stringency and necessity of the regulation. The Gallup Refinery, owned and operated by Western Refining Southwest, Inc. (Western), appreciates the opportunity to participate in the rule review process. This letter provides Western's initial response to NMED's request for comments.

Questions to Stakeholders about the Rule:

1. ***Do you have preferences on whether the rule is revised, repealed or no action is taken?***

   Western prefers that Part 36 **be repealed in its entirety** for the following reasons.

   - As stated in the NMED letter dated April 1, 2014, the established federal New Source Performance Standards (NSPS), 40 CFR 60, Subparts J and Ja include detailed emission limits, continuous monitoring, recordkeeping, and reporting requirements for sulfur emissions from petroleum refinery units. In comparison to Part 36, NSPS Subparts J and Ja are more robust and comprehensive in enforcement of the same standards.

   - The rule definition for existing and new facilities is ambiguous and confusing. The Gallup Refinery was constructed prior to July 1, 1974 as an "Existing Facility" per the Part 36 definition. Therefore, the Gallup Refinery is not subject to the "New Facility" requirements under Part 36. However, Gallup is complying with the new facility requirements due to NSPS applicability.

   - With respect to reporting requirements, Gallup agrees with the statement in the NMED letter, *"Part 36 quarterly reporting can be redundant as subject facilities are required to submit semi-annual reports required by Subparts J and Ja, and semi-annual and annual compliance reports required by Title V permits."*

   - The Gallup Refinery has been in compliance with the reporting requirements specified under 20.2.36.113A NMAC. The quarterly report focus on the facility-wide

sulfur balance that does not provide needed information for air quality impact evaluations. The sulfur dioxide (SO_2) emissions are reported in the annual emissions inventory, which can be used to demonstrate compliance with emissions limits. The annual emissions inventory data is also used by Federal and State agencies for ambient air quality analysis in the rulemaking process. The Part 36 reporting requirement does not add value for compliance demonstrations nor for air quality improvement.

2. ***Would you be interested in participating in a work group for further analysis of the rule?***

   Western is interested in participating in this work group.

Thank you for the opportunity to provide the comments in this letter. Western would be happy to participate in the upcoming work group for the rule. In the meantime, feel free to call me at to further discuss the contents of this letter.

Sincerely,

Ed Riege
Environmental Manager, Gallup Refinery
Western Refining Southwest, Inc.

United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225-0287

TRANSMITTED VIA ELECTRONIC MAIL - NO HARDCOPY TO FOLLOW

N3615 (2350)

April 30, 2014

Mark Jones
Environmental Analyst
Air Quality Bureau
New Mexico Environment Department
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico, 87505

Dear ~~Mr. Jones~~ Mark:

The New Mexico Environment Department (NMED), Air Quality Bureau is currently reviewing and evaluating two existing state rules:

- 20.2.36 NMAC – Petroleum Refinery - Sulfur (Part 36), which establishes sulfur limits (sulfur recovery standards) and other requirements for existing (constructed prior to July 1, 1974) and new petroleum refineries. According to NMED, "Part 36 has enforceability issues due to a lack of monitoring and recordkeeping requirements."
- 20.2.37 NMAC – Petroleum Processing Facilities (Part 37), which establishes emissions limits and other operating requirements for existing (constructed prior to July 1, 1974) and new petroleum refineries and natural gas processing facilities. According to NMED, "Enforcement of Part 37 may be problematic due to an absence of monitoring and recordkeeping requirements."

These rules were identified in New Mexico's November 2012 Improving Environmental Permitting Report as rules for potential revision or repeal.

We have the following concerns about NMED's potential actions to repeal these rules:

- While the November 2012 Improving Environmental Permitting Report identifies both parts 36 and 37 as "Potential Air Quality Rules to Repeal or Revise," it provides no explanation or justification for these recommendations.
- Part 36 contains absolute limits on sulfur emissions that are not provided by the New Source Performance Standards (NSPS) Subparts J and Ja. Part 37 appears to be more comprehensive (covering more/different emission units and pollutants) than the NSPS.

NMED should discuss the rationale behind the original adoption of parts 36 and 37, as well as revisions that could be adopted to resolve the "enforceability issues" cited in your letter.

We are pleased that NMED has committed to ". . . evaluat(ing) whether the repeal of this rule would negatively affect air quality." In the absence of such an evaluation, our initial preference is that NMED revise these rules to address the issues noted by NMED. We would also like to accept your invitation to participate in a work group to further analyze the rule. If you have questions, please contact Don Shepherd at (303) 969-2075.

Sincerely,

Susan Johnson
Chief, Policy, Planning, and Permit Review Branch

NOTICE OF RULEMAKING HEARING

The New Mexico Environmental Improvement Board ("Board") will hold a public hearing on December 18, 2015 at 9:00 a.m. in room 307 of the New Mexico State Capitol Building, 490 Old Santa Fe Trail, Santa Fe, New Mexico. The purpose of the hearing is to consider the matter of EIB 15-03 (R), a proposed repeal of 20.2.36 NMAC, *Petroleum Refinery - Sulfur.*

The proponent of this regulatory amendment is the New Mexico Environment Department ("NMED").

The purpose of the public hearing is to consider and take possible action on a petition from the NMED to repeal 20.2.36 NMAC. The purpose of the proposed repeal of 20.2.36 NMAC is to remove outdated, redundant requirements. The federal New Source Performance Standards (NSPS) regulations, 40 CFR Part 60, Subparts J and Ja and other permit requirements require sulfur emission limits that are more directly related to air emissions of sulfur than 20.2.36 NMAC, and require continuous monitoring, which provides for more effective enforcement of the emission limits. Since these federal regulations are in place for sulfur limits for existing and future refineries, a repeal of 20.2.36 NMAC would not negatively affect air quality.

The NMED will host informational open houses on the proposed repeal of 20.2.36 NMAC at the NMED Roswell Office training room, 1914 W. Second, Roswell, NM 88201 from 2:30 p.m. to 4:30 p.m. on Thursday, October 29, 2015 and at the NMED Albuquerque District Office, 121 Tijeras Ave. NE, STE 1000, Albuquerque, NM 87102 in the Alameda conference room from 3:30 p.m. to 5:30 p.m. on Tuesday November 3, 2015. For questions regarding the open house, please contact Mark Jones at 505-566-9746 or mark.jones@state.nm.us.

Full text of NMED's proposed repealed regulation is available on NMED's web site at www.env.nm.gov/aqb or by contacting Mark Jones at 505-566-9746 or mark.jones@state.nm.us. The proposed repealed regulation may also be examined during office hours at the Air Quality Bureau office, 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico.

The hearing will be conducted in accordance with 20.1.1 NMAC (*Rulemaking Procedures – Environmental Improvement Board*), the *Environmental Improvement Act*, NMSA 1978, Section 74-1-9, the *Air Quality Control Act*, NMSA 1978, Section 74-2-6, and other applicable procedures.

All interested persons will be given reasonable opportunity at the hearing to submit relevant evidence, data, views and arguments, orally or in writing, to introduce exhibits, and to examine witnesses. Persons wishing to present technical testimony must file with the Board a written notice of intent to do so. The notice of intent shall:

(1) identify the person for whom the witness(es) will testify;
(2) identify each technical witness that the person intends to present and state the qualifications of the witness, including a description of their education and work background;
(3) include a copy of the direct testimony of each technical witness in narrative form;
(4) include the text of any recommended modifications to the proposed regulatory change; and
(5) list and attach all exhibits anticipated to be offered by that person at the hearing, including any proposed statement of reasons for adoption of rules.

Notices of intent for the hearing must be received in the Office of the Board not later than 5:00 pm on November 25, 2015, and should reference the docket number, EIB 15-03 (R), and the date of the hearing. Notices of Intent to present technical testimony should be submitted to:

Pam Castañeda, Board Administrator
Environmental Improvement Board
1190 S. St. Francis Drive, Room S-2102
Santa Fe, NM 87502
Phone: (505) 827-2425, Fax (505) 827-0310

NMED Exhibit 11a

Any member of the general public may testify at the hearing. No prior notification is required to present non-technical testimony at the hearing. Any such member may also offer exhibits in connection with his testimony, so long as the exhibit is not unduly repetitious of the testimony.

A member of the general public who wishes to submit a written statement for the record, in lieu of providing oral testimony at the hearing, shall file the written statement prior to the hearing, or submit it at the hearing.

Persons having a disability and needing help in being a part of this hearing process should contact J.C. Borrego of the NMED Human Resources Bureau by December 1, 2015 at P.O. Box 5469, 1190 St. Francis Drive, Santa Fe, New Mexico, 87502, telephone 505-827-0424 or email juancarlos.borrego@state.nm.us. TDY users please access his number via the New Mexico Relay Network at 1-800-659-8331.

The Board may make a decision on the proposed revised regulation at the conclusion of the hearing, or the Board may convene a meeting after the hearing to consider action on the proposal.

NOTIFICACIÓN DE REUNIÓN PÚBLICA Y AUDIENCIA DE REGLAMENTACIÓN

La Junta de Mejora Ambiental de Nuevo México ("Junta") celebrará una audiencia pública el 18 de Diciembre, 2015 a las 9:00 a.m. en el edificio del Capitolio del Nuevo México, Sala 307, Santa Fe, Nuevo México. El propósito de la audiencia es considerar el asunto de EIB 15-03 (R), una propuesta de derogación de 20.2.36 NMAC , Refinería – Azufre.

El proponente de esta revocación y reemplazo reguladora es el Departamento del Medio Ambiente de Nuevo México ("NMED").

El propósito de la audiencia pública es considerar y tomar una posible acción en una petición del NMED derogar 02/20/36 NMAC. El propósito de la propuesta de derogación de 20.2.36 NMAC es eliminar requisitos anticuados, redundantes. Las Normas de Desempeño de Nuevas Fuentes (NSPS) las regulaciones federales, 40 CFR Parte 60, otros requisitos del permiso subpartes J y Ja y requieren límites de emisión de azufre que están más directamente relacionados con las emisiones atmosféricas de azufre que el 20.2.36 NMAC, y requieren un seguimiento continuo, que prevé una aplicación más efectiva de los límites de emisión. Dado que estas regulaciones federales están en su lugar para los límites de azufre de las refinerías existentes y futuras, la derogación de 20.2.36 NMAC no afectaría negativamente a la calidad del aire.

El NMED acogerá jornadas de puertas abiertas de información sobre la propuesta de derogación de 20.2.36 NMAC a la sala de entrenamiento NMED Oficina Roswell, 1914 W. En segundo lugar, Roswell, NM 88 201 14:30-16:30 en Jueves, 29 de octubre 2015 y en la Oficina del Distrito NMED Albuquerque, 121 Tijeras Ave. NE, STE 1000, Albuquerque, NM 87102, en la sala de conferencias Alameda 15:30-17:30 el martes 3 de noviembre de 2015. Si tienes preguntas sobre la jornada de puertas abiertas, por favor póngase en contacto con Mark Jones al 505-566-9746 mark.jones@state.nm.us.

Texto completo de la regulación derogada propuesto por NMED está disponible en el sitio Web de NMED en www.env.nm.gov/aqb o poniéndose en contacto con Mark Jones al 505-566-9746 or mark.jones@state.nm.us. La regulación revisada propuesta podrá ser examinada en horario de oficina en la Oficina de la Agencia de Calidad del Aire del NMED, en 525 Camino de los Marquez, Suite 1, Santa Fe, Nuevo México.

La audiencia se realizará de conformidad con 20.1.1 NMAC (Procedimientos de Reglamentación – Consejo para la Mejora del Medio Ambiente), la Ley de Mejora del Medio Ambiente, Sección 74-1-9 NMSA 1978, la Ley de Control de Calidad del Aire, Sección, 74-2-6 NMSA 1978, y otros procedimientos aplicables.

Todas las personas interesadas tendrán oportunidad razonable en la audiencia de presentar pruebas, datos, opiniones y argumentos importantes, ya sea en forma verbal o por escrito, así como de presentar anexos e interrogar testigos. Las personas que deseen entregar testimonios técnicos deben presentar ante el Consejo una notificación por escrito de su intención. La notificación de intención deberá:

(1) identificar a la persona para quien testificará(n) el(los) testigo(s);
(2) identificar a cada uno de los testigos técnicos que las personas desean presentar y declarar las cualificaciones de los mismos, incluyendo una descripción de sus antecedentes de educación y trabajo;
(3) resumir o incluir una copia del testimonio directo de cada testigo técnico y declarar la duración prevista del testimonio de ese testigo;
(4) enumerar y describir, o adjuntar, cada uno de los anexos que dicha persona prevé ofrecer en la audiencia; y
(5) adjuntar el texto de cualquier modificación recomendada a las regulaciones propuestas nuevas y revisadas.

Las notificaciones de intención para la audiencia deben ser recibidas en la Oficina del Consejo a más tardar a las 5:00 p.m., el 25 de Noviembre de 2015, y hacer referencia al número de expediente, EIB 15-03(R), y la fecha de la audiencia. Las notificaciones de intención para presentar testimonios técnicos se deben entregar a:

Pam Castañeda, Administradora de la Junta
Oficina de la Junta de Mejoramiento Ambiental
1190 S. St. Francis Drive, Room S-2102
Santa Fe, NM 87502

NMED Exhibit 11a

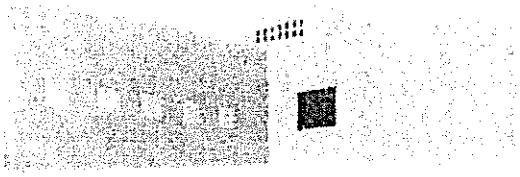
Teléfono: (505) 827-2425, Fax (505) 827-0310

Cualquier miembro del público en general puede testificar en la audiencia. No se requiere notificación previa para presentar testimonios no técnicos en la audiencia. Los miembros del público también pueden ofrecer anexos en relación con su testimonio, en tanto no sean repeticiones excesivas de su testimonio.

Los miembros del público en general que deseen presentar una declaración por escrito para el registro, en vez de ofrecer testimonio verbal en la audiencia, presentarán la declaración por escrito antes de la audiencia, o la presentarán en la misma.

Las personas con discapacidad y que necesiten ayuda para ser parte de este proceso de la audiencia deberán contactar a Juan Carlos Borrego de la oficina de recurso humanos NMED por 01 de julio, 2014, P.O. Box 26110, 1190 St. Francis Drive, Santa Fe, Nuevo México, 87502, teléfono 505-827-0424 o correo electrónico juancarlos.borrego@state.nm.us. Los usuarios de TDY deben acceder a su número a través de la Red de Difusión de Nuevo México, al 1-800-659-8331.

La Junta puede tomar la decisión sobre las regulaciones propuestas revisadas a la conclusión de la audiencia, o bien acordar una reunión para una fecha posterior a fin de considerar las acciones sobre la propuesta.



NM Commission of Public Records
1205 Camino Carlos Rey
Santa Fe 87507 US
(505) 476-7913

Invoice

BILL TO
NM Environment Department
Air Quality Bureau
525 Camino de los Marquez
Suite 1
Santa Fe, NM 87505

INVOICE #	DATE	TOTAL DUE	DUE DATE	ENCLOSED
1225	09/30/2015	$122.50	09/30/2015	

ISSUE	PUBLICATION	P.O. NUMBER
18	9/29/2015	66700-0000024960

DATE	ACTIVITY	QTY	RATE	AMOUNT
09/30/2015	Columnar Inch - N.M. Register, Vol. XXVI, Notice Notice of Rulemaking Hearing	23	2.50	57.50
09/30/2015	Columnar Inch - N.M. Register, Vol. XXVI, Notice Notificacion de Reunion Publica y Audiencia de Reglamentacion	26	2.50	65.00

I, Matt Ortiz, certify that the agency noted above has published legal notices or rules in the NEW MEXICO REGISTER, VOL. XXVI, and that payment has been assessed for said legal notice or publication, which appears on the publication date and issue number noted above.

BALANCE DUE $122.50

Affiant: _____, Publisher New Mexico Register

Subscribed, sworn and acknowledged before me this 6 day of October, 2015.

Notary Public

OFFICIAL SEAL
Amanda N. Lopez
NOTARY PUBLIC-STATE OF NEW MEXICO
My commission expires: 5/5/2019

My Commission Expires: May 5, 2019

RECEIVED
OCT 9 2015
Air Quality Bureau

NMED Exhibit 11b

AFFIDAVIT OF PUBLICATION

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OCT 9 2015
Air Quality Bureau

STATE OF NEW MEXICO
County of Bernalillo SS

Linda MacEachen, being duly sworn, declares and says that she is Classified Advertising Manager of The Albuquerque Journal, and that this newspaper is duly qualified to publish legal notices or advertisements within the meaning of Section 3, Chapter 167, Session Laws of 1937, and that payment therefore has been made of assessed as court cost; that the notice, copy of which is hereto attached, was published in said paper in the regular daily edition, for 1 times on the following dates:

September 16, 2015

Linda MacEachen

Sworn and subscribed before me, a Notary Public, in and for the County of Bernalillo and State of New Mexico this 16 day of September of 2015.

OFFICIAL SEAL
Sandra B. Gutierrez
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires: 2-18-17

Sandra B. Gutierrez

#

PRICE 132.36

Statement to come at end of month.

ACCOUNT NUMBER 1002594

NEW MEXICO ENVIRONMENTAL IMPROVEMENT BOARD
NOTICE OF RULEMAKING HEARING

The New Mexico Environmental Improvement Board ("Board") will hold a public hearing on December 18, 2015 at 9:00 a.m. in room 307 of the New Mexico State Capitol Building, 490 Old Santa Fe Trail, Santa Fe, New Mexico. The purpose of the hearing is to consider the matter of EIB 15-03 (R), a proposed repeal of 20.2.36 NMAC, Petroleum Refinery - Sulfur.

The proponent of this regulatory amendment is the New Mexico Environment Department ("NMED").

The purpose of the public hearing is to consider and take possible action on a petition from the NMED to repeal 20.2.36 NMAC. The purpose of the proposed repeal of 20.2.36 NMAC is to remove outdated, redundant requirements. The federal New Source Performance Standards (NSPS) regulations, 40 CFR Part 60, Subparts J and Ja and other permit requirements require sulfur emission limits that are more directly related to air emissions of sulfur than 20.2.36 NMAC, and require continuous monitoring, which provides for more effective enforcement of the emission limits. Since these federal regulations are in place for sulfur limits for existing and future refineries, a repeal of 20.2.36 NMAC would not negatively affect air quality.

The NMED will host informational open houses on the proposed repeal of 20.2.36 NMAC at the NMED Roswell Office training room, 1914 W. Second, Roswell, NM 88201 from 2:30 p.m. to 4:30 p.m. on Thursday, October 29, 2015 and at the NMED Albuquerque District Office, 121 Tijeras Ave. NE, STE 1000, Albuquerque, NM 87102 in the Alameda conference room from 3:30 p.m. to 5:30 p.m. on Tuesday, November 3, 2015. For questions regarding the open house, please contact Mark Jones at 505-566-9746 or mark.jones@state.nm.us.

Full text of NMED's proposed repealed regulation is available on NMED's web site at www.env.nm.gov/aqb or by contacting Mark Jones at 505-566-9746 or mark.jones@state.nm.us. The proposed repealed regulation may also be examined during office hours at the Air Quality Bureau office, 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico.

The hearing will be conducted in accordance with 20.1.1 NMAC (Rulemaking Procedures - Environmental Improvement Board), the Environmental Improvement Act, NMSA 1978, Section 74-1-9, the Air Quality Control Act, NMSA 1978, Section 74-2-6, and other applicable procedures.

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(3) include a copy of the direct testimony of each technical witness in narrative form;

(4) include the text of any recommended modifications to the proposed regulatory change; and

(5) list and attach all exhibits anticipated to be offered by that person at the hearing, including any proposed statement of reasons for adoption of rules.

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Pam Castañeda, Board Administrator
Environmental Improvement Board
1190 S. St. Francis Drive, Room S-2102
Santa Fe, NM 87502
Phone: (505) 827-2425, Fax (505) 827-0310

Any member of the general public may testify at the hearing. No prior notification is required to present non-technical testimony at the hearing. Any such member may also offer exhibits in connection with his testimony, so long as the exhibit is not unduly repetitious of the testimony.

A member of the general public who wishes to submit a written statement for the record, in lieu of providing oral testimony at the hearing, shall file the written statement prior to the hearing, or submit it at the hearing.

Persons having a disability and needing help in being a part of this hearing process should contact J.C. Borrego of the NMED Human Resources Bureau by December, 1, 2015 at P.O. Box 5469, 1190 St. Francis Drive, Santa Fe, New Mexico, 87502, telephone 505-827-0424 or email juancarlos.borrego@state.nm.us. TDY users please access his number via the New Mexico Relay Network at 1-800-659-8331.

The Board may make a decision on the proposed revised regulation at the conclusion of the hearing, or the Board may convene a meeting after the hearing to consider action on the proposal.

Journal: September 16, 2015

NMED Exhibit 11c

AFFIDAVIT OF PUBLICATION

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OCT 9 2015

Air Quality Bureau

STATE OF NEW MEXICO
County of Bernalillo SS

Linda MacEachen, being duly sworn, declares and says that she is Classified Advertising Manager of The Albuquerque Journal, and that this newspaper is duly qualified to publish legal notices or advertisements within the meaning of Section 3, Chapter 167, Session Laws of 1937, and that payment therefore has been made of assessed as court cost; that the notice, copy of which is hereto attached, was published in said paper in the regular daily edition, for 1 times on the following dates:

September 16, 2015

Linda MacEachen

Sworn and subscribed before me, a Notary Public, in and for the County of Bernalillo and State of New Mexico this 16 day of September of 2015

OFFICIAL SEAL
Sandra B. Gutierrez
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires: 2-28-17

Sandra B. Gutierrez

PRICE #149-91

Statement to come at end of month.

ACCOUNT NUMBER 1007574

CONSEJO PARA LA MEJORA DEL MEDIO AMBIENTE DE NUEVO MÉXICO
NOTIFICACIÓN DE REUNIÓN PÚBLICA Y AUDIENCIA DE REGLAMENTACIÓN

La Junta de Mejora Ambiental de Nuevo México ("Junta") celebrará una audiencia pública el 18 de Diciembre, 2015 a las 9:00 a.m. en el edificio del Capitolio del Nuevo México, Sala 307, Santa Fe, Nuevo México. El propósito de la audiencia es considerar el asunto de EIB 15-03 (R), una propuesta de derogación de 20.2.36 NMAC , Refinería - Azufre.

El proponente de esta revocación y reemplazo reguladora es el Departamento del Medio Ambiente de Nuevo México ("NMED").

El propósito de la audiencia pública es considerar y tomar una posible acción en una petición del NMED derogar 02/20/36 NMAC. El propósito de la propuesta de derogación de 20.2.36 NMAC es eliminar requisitos anticuados, redundantes. Las Normas de Desempeño de Nuevas Fuentes (NSPS) las regulaciones federales, 40 CFR Parte 60, otros requisitos del permiso subpartes J y Ja y requieren límites de emisión de azufre que están más directamente relacionados con las emisiones atmosféricas de azufre que el 20.2.36 NMAC, y requieren un seguimiento continuo, que prevé una aplicación más efectiva de los límites de emisión. Dado que estas regulaciones federales están en su lugar para los límites de azufre de las refinerías existentes y futuras, la derogación de 20.2.36 NMAC no afectaría negativamente a la calidad del aire.

El NMED acogerá jornadas de puertas abiertas de información sobre la propuesta de derogación de 20.2.36 NMAC a la sala de entrenamiento NMED Oficina Roswell, 1914 W. En segundo lugar, Roswell, NM 88 201 14:30-16:30 en Jueves, 29 de octubre 2015 y en la Oficina del Distrito NMED Albuquerque, 121 Tijeras Ave NE, STE 1000, Albuquerque, NM 87102, en la sala de conferencias Alameda 15:30-17:30 el martes 3 de noviembre de 2015. Si tienes preguntas sobre la jornada de puertas abiertas, por favor póngase en contacto con Mark Jones al 505-566-9746 o mark.jones@state.nm.us

Texto completo de la regulación derogada propuesto por NMED está disponible en el sitio Web de NMED en www.env.nm.gov/aqb o poniéndose en contacto con Mark Jones al 505-566-9746 or mark.jones@state.nm.us. La regulación revisada propuesta podrá ser examinada en horario de oficina en la Oficina de la Agencia de Calidad del Aire del NMED, en 525 Camino de los Marquez, Suite 1, Santa Fe, Nuevo México.

La audiencia se realizará de conformidad con 20.1.1 NMAC (Procedimientos de Reglamentación - Consejo para la Mejora del Medio Ambiente), la Ley de Mejora del Medio Ambiente, Sección 74-1-9 NMSA 1978, la Ley de Control de Calidad del Aire, Sección, 74-2-6 NMSA 1978, y otros procedimientos aplicables.

Todas las personas interesadas tendrán oportunidad razonable en la audiencia de presentar pruebas, datos, opiniones y argumentos importantes, ya sea en forma verbal o por escrito, así como de presentar anexos e interrogar testigos. Las personas que deseen entregar testimonios técnicos deben presentar ante el Consejo una notificación por escrito de su intención. La notificación de intención deberá:

(1) identificar a la persona para quien testificará(n) el(los) testigo(s);

(2) identificar a cada uno de los testigos técnicos que las personas desean presentar y declarar las cualificaciones de los mismos, incluyendo una descripción de sus antecedentes de educación y trabajo;

(3) resumir o incluir una copia del testimonio directo de cada testigo técnico y declarar la duración prevista del testimonio de ese testigo;

(4) enumerar y describir, o adjuntar, cada uno de los anexos que dicha persona prevé ofrecer en la audiencia; y

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Las notificaciones de intención para la audiencia deben ser recibidas en la Oficina del Consejo a más tardar a las 5:00 p.m., el 25 de Noviembre de 2015, y hacer referencia al número de expediente, EIB 15-03(R), y la fecha de la audiencia. Las notificaciones de intención para presentar testimonios técnicos se deben entregar a:

Pam Castañeda,
Administradora de la Junta
Oficina de la Junta
de Mejoramiento Ambiental
1190 S. St. Francis Drive,
Room S-2102
Santa Fe, NM 87502
Teléfono: (505) 827-2425,
Fax (505) 827-0310

Cualquier miembro del público en general puede testificar en la audiencia. No se requiere notificación previa para presentar testimonios no técnicos en la audiencia. Los miembros del público también pueden ofrecer anexos en relación con su testimonio, en tanto no sean repeticiones excesivas de su testimonio.

Los miembros del público en general que deseen presentar una declaración por escrito para el registro, en vez de ofrecer testimonio verbal en la audiencia, presentarán la declaración por escrito antes de la audiencia, o la presentarán en la misma.

Las personas con discapacidad y que necesiten ayuda para ser parte de este proceso de la audiencia deberán contactar a Juan Carlos Borrego de la oficina de recurso humanos NMED por 01 de julio, 2014, P.O. Box 26110, 1190 St. Francis Drive, Santa Fe, Nuevo México, 87502, teléfono 505-827-0424 o correo electrónico juancarlos.borrego@state.nm.us. Los usuarios de TDY deben acceder a su número a través de la Red de Difusión de Nuevo México, al 1-800-659-8331.

La Junta puede tomar la decisión sobre las regulaciones propuestas revisadas a la conclusión de la audiencia, o bien acordar una reunión para una fecha posterior a fin de considerar las acciones sobre la propuesta.
Journal: September 16, 2015

NMED Exhibit 11d

COPY

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REPEAL OF: **No. EIB 15-03**
20.2.36 NMAC – *Petroleum Refinery - Sulfur*

NEW MEXICO ENVIRONMENT DEPARTMENT'S
NOTICE OF COMPLIANCE WITH
SMALL BUSINESS REGULATORY RELIEF ACT

The New Mexico Environment Department gives notice that it has filed in the record of this proceeding a letter dated August 7, 2015, to the Small Business Regulatory Advisory Commission, a copy of which is attached hereto, as required by NMSA 1978, Section 14-4A-4 of the Small Business Regulatory Relief Act.

Respectfully submitted,

John B. Verheul
Assistant General Counsel
1190 St. Francis Drive
Santa Fe, New Mexico 87505
(505) 383-2063
John.Verheul@state.nm.us

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Notice of Compliance* was served on the following parties on this the 11th day of August, 2015 via the stated delivery methods below:

Hand delivery:
Ms. Pam Castaneda, Administrator
Environmental Improvement Board
Room S-2102, Runnels Building
1190 St. Francis Dr.
Santa Fe, New Mexico 87505

Email:
Joseph M. Dworak
Assistant Attorney General
Office of the New Mexico Attorney General
P.O. Drawer 1508
Santa Fe, New Mexico 87504
Counsel for Environmental Improvement Board
jdworak@nmag.gov

Billy Jimenez

NMED Exhibit 12

NEW MEXICO
ENVIRONMENT DEPARTMENT

Office of General Counsel

SUSANA MARTINEZ
Governor
JOHN A SANCHEZ
Lieutenant Governor

RYAN FLYNN
Cabinet Secretary
BUTCH TONGATE
Deputy Secretary

Harold Runnels Building
1190 Saint Francis Drive (87505)
PO Box 5469, Santa Fe, NM 87502-5469
Phone (505) 827-2990 Fax (505) 827-1628
www.nmenv.state.nm.us

Via Electronic Mail: Leslie.A.Porter@state.nm.us

August 7, 2015

Small Business Regulatory Advisory Commission
c/o Ms. Leslie Porter
New Mexico Economic Development Department
1100 St. Francis Drive
Santa Fe, New Mexico 87501

Re: Proposed Repeal of 20.2.36 NMAC – *Petroleum Refinery – Sulfur*

Dear Ms. Porter,

The New Mexico Environment Department ("Department") hereby provides notice to the Small Business Regulatory Advisory Commission, pursuant to the Small Business Regulatory Relief Act ("Act"), NMSA 1978, Sections 14-4A-1 to -5 (2005), that the Environmental Protection Division, Air Quality Bureau ("Bureau") has submitted a petition to the Environmental Improvement Board (EIB) for the repeal of 20.2.36 New Mexico Administrative Code (NMAC).

The purpose of the proposed repeal is to remove outdated, redundant requirements. The federal New Source Performance Standards (NSPS) regulations 40 CFR Part 60, Subparts J and Ja also require sulfur emission limits that are more directly related to air emissions of sulfur than 20.2.36 NMAC, and require continuous monitoring which provides for more effective enforcement of the emission limits. Since these federal regulations more effectively control sulfur emissions from existing and future refineries, a repeal of 20.2.36 NMAC would not negatively affect air quality.

At present, there are three petroleum refineries in New Mexico: Navajo Refining – Artesia, Navajo Refining – Lovington, and Western Refining in Gallup, NM. These are the only businesses which will be affected by the proposed repeal of 20.2.36 NMAC, and none of them are small businesses as defined in the Act.

The EIB will hold a hearing on the proposed regulatory amendments (Docket No. EIB 15-03 (R)) currently scheduled for Friday, December 18, 2015. For details regarding the time and location of the hearing please check the EIB website at: http://www.env.nm.gov eib/.

Pursuant to Section 14-4A-4 of the Act, the Department does not anticipate that the proposed regulatory amendments will have any adverse effect on small businesses. If you require further information about these proposed regulatory amendments, please call me at (505) 383-2063 or email me at john.verheul@state.nm.us.

Sincerely,

John B. Verheul
Assistant General Counsel
New Mexico Environment Department

cc: Kerwin Singleton, Air Quality Bureau, via email
Mark Jones, Air Quality Bureau, via email

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REPEAL OF: **No. EIB 15-03 (R)**
20.2.36 NMAC – *Petroleum Refinery - Sulfur*

ORDER AND STATEMENT OF REASONS
FOR REPEAL OF 20.2.36 NMAC

This matter comes before the New Mexico Environmental Improvement Board ("Board") upon a petition filed by the New Mexico Environment Department ("NMED" or "Department"), proposing amendments to New Mexico's Air Quality Regulations, in order to repeal 20.2.36 NMAC – *Petroleum Refinery – Sulfur*. A public hearing was held in Santa Fe, New Mexico on December 18, 2015, with a quorum of the Board present during the hearing. The Board heard technical testimony from the Department and admitted exhibits into the record. On December 18, 2015, the Board deliberated and voted to adopt the proposed repeal for the reasons that follow:

I. STATEMENT OF REASONS

1. 20.2.36 NMAC, *Petroleum Refinery – Sulfur* ("Part 36") establishes sulfur limits (sulfur recovery standards) and other requirements for existing (constructed prior to July 1, 1974) and new petroleum refineries.
2. The U.S. Environmental Protection Agency ("EPA") New Source Performance Standards (NSPS) regulations, 40 CFR Part 60, Subparts J and Ja ("NSPS J and Ja") require concentration-based sulfur emission limits that are more directly related to sulfur air emissions than Part 36.

NMED Exhibit 13

3. Part 36 bases the reductions of sulfur recovered on a mass balance (weight in pounds) that occur during some refining processes; in comparison, NSPS J and Ja require concentration-based emission limits (parts per million by volume, or ppmv) from specific emission release points.

4. Existing information contained in sulfur reporting forms submitted by permitted refineries in New Mexico and regulatory comparisons between Part 36 and NSPS J and Ja submitted by Western Refining Company and Navajo Refining Company show that NSPS J and Ja result in control requirements that are more directly related to sulfur air emissions and their impact on air quality.

5. Part 36 was adopted in 1974 at a time when Continuous Emissions Monitoring Systems (CEMS) were not widely in use. This leads to enforceability issues due to a lack of monitoring requirements. Also, the regulation is not part of the State Implementation Plan (SIP) under the federal Clean Air Act, and therefore is not federally enforceable by the EPA. In comparison, Subparts J and Ja require continuous monitoring, which provides for more effective enforcement of the emission limits. Subparts J and Ja have been adopted by reference in 20.2.77 NMAC and are both state and federally enforceable.

6. With respect to reporting requirements, Part 36 quarterly reporting can be redundant, as subject facilities are also required to submit semi-annual reports required by NSPS J and Ja, and semi-annual reports and annual compliance certifications required by Clean Air Act Title V permits. Calculating mass balance reports required by Part 36 requires the use of engineering resources at refineries, as well as Department resources to review and process the submittals.

7. Pursuant to 20.1.1.300.A NMAC, any person may petition the Board for amendment of regulations within the jurisdiction of the Board.

8. On June 19, 2015 NMED filed a petition with the Board for a public hearing in this matter. The petition proposed that Part 36 be repealed.

9. On July 17, 2015, at a meeting conducted in compliance with the Open Meetings Act and other applicable requirements, the Board granted the Department's request for a hearing and scheduled the hearing for October 16, 2015.

10. On September 18, 2015, at a special meeting, the Board rescheduled the hearing for December 18, 2015.

11. Public notice of the hearing was published on the NMED AQB website on September 15, 2015, on the NMED AQB electronic mail list on October 16, 2015, in the Albuquerque Journal (in English and Spanish) on September 16, 2015 and in the New Mexico Register on October 15, 2015. The notice stated that the Board may make a decision on the proposed amendments at the conclusion of the hearing, or may convene at a later date to consider action on the proposal.

12. NMED filed a Notice of Intent to Present Technical Testimony (NOI) on November 25, 2015, in accordance with 20.1.1.302 NMAC.

13. No other parties filed NOIs.

14. A hearing in this matter was held in Santa Fe, New Mexico on December 18, 2015, at which a reasonable opportunity for all persons to be heard was provided.

15. The Board has the authority to adopt the proposed amendments pursuant to NMSA 1978, §§ 74-2-5.B & C.

16. In considering the proposed amendments, the Board is required by the Air Quality Control Act, NMSA 1978, Section 74-2-5.E, to give weight it deems appropriate to all facts and circumstances, including but not limited to (1) character and degree of injury to or interference with health, welfare, visibility and property; (2) the public interest, including the social and economic value of the sources and subjects of air contaminants; and (3) technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved and previous experience with equipment and methods available to control the air contaminants involved.

17. The proposed amendments do not cause injury or interfere with health, welfare, visibility and property, in accordance with NMSA, Section 74-2-5.E(1); nor do they relate to the technical practicability and economic reasonableness of reducing or eliminating air contaminants, in accordance with NMSA, Section 74-2-5.E(3).

18. In addition, in accordance with NMSA, Section 74-2-5.E(2), the Board concludes that the public interest will be served by the repeal of Part 36. Specifically, repeal of Part 36 would benefit the state by removing outdated, redundant requirements. Since federal regulations are in place for sulfur limits for existing and future refineries, a repeal of Part 36 would not negatively affect air quality.

19. The Board concludes that the factors specified by NMSA 1978, Section 74-2-5.E all weigh in favor of adopting the proposed amendments.

20. The notice and hearing requirements of NMSA 1978 Section 74-2-6 and 20.1.1 NMAC were satisfied in this rulemaking process.

21. The proposed amendments are adopted for any or all of the reasons stated above.

II. ORDER

By majority vote of a quorum of the Board members, the proposed revisions to New Mexico's Air Quality Regulations, to repeal 20.2.36 NMAC– *Petroleum Refinery – Sulfur*, as contained in NMED's June 19, 2015 petition and request for hearing, were approved by the Board on December 18, 2015.

_____ Dated: _____

On Behalf of the Board