IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

CLEAN AIR COUNCIL, EARTHWORKS, ENVIRONMENTAL DEFENSE FUND, ENVIRONMENTAL INTEGRITY PROJECT, NATURAL RESOURCES DEFENSE COUNCIL and SIERRA CLUB,	
Petitioners	No. 17-1145
v.	
SCOTT PRUITT, Administrator, United States Environmental Protection Agency, and UNITED STATES ENVIRONMENTAL PROTECTION, AGENCY,	
Respondents.	

ATTACHMENTS TO EMERGENCY MOTION FOR A STAY OR, IN THE ALTERNATIVE, SUMMARY VACATUR

Volume 1 – Attachments 1 to 16

SUSANNAH L. WEAVER
SEAN H. DONAHUE
Donahue & Goldberg, LLP
1111 14th Street, NW
Suite 510A
Washington, DC 20005
Telephone: (202) 569-3818
Facsimile: (202) 289-8009
susannah@donahuegoldberg.com
Counsel for Petitioner Environmental Defense Fund

June 5, 2017

PETER ZALZAL
ALICE HENDERSON
VICKIE PATTON
Environmental Defense Fund
2060 Broadway, Ste. 300
Boulder, CO 80302
Telephone: (303) 447-7214
pzalzal@edf.org
TOMÁS CARBONELL
Environmental Defense Fund
1875 Connecticut Ave., 6th Floor
Washington, D.C., 20009
Telephone: (202) 572-3610
tcarbonell@edf.org
Counsel for Petitioner Environmental Defense Fund

ANDRES RESTREPO
Sierra Club
50 F St., NW, Eighth Floor
Washington, DC 20001
Telephone: (202) 650-6073
Andres.Restrepo@sierraclub.org
JOANNE MARIE SPALDING
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
Telephone: (415) 997-5725
Joanne.Spalding@sierraclub.org
Counsel for Petitioner Sierra Club

ANN BREWSTER WEEKS
DARIN SCHROEDER
Clean Air Task Force
18 Tremont, Suite 530
Boston, MA 02108
Telephone: (617) 624-0234
aweeks@catf.us
dschroeder@catf.us
Counsel for Petitioner Earthworks

DAVID DONIGER
Natural Resources Defense Council
1152 15th St. NW, Suite 300
Washington, DC 20005
(202) 513-6256
ddoniger@nrdc.org
MELEAH GEERTSMA
Natural Resources Defense Council
2 N. Wacker Drive, Suite 1600
Chicago, IL 60606
Telephone: (312) 651-7904
mgeertsma@nrdc.org
Counsel for Petitioner Natural Resources Defense Council

TIM BALLO
Earthjustice
1625 Massachusetts Ave., NW
Suite 702
Washington, DC 20036
Telephone: (202) 667-4500
tballo@earthjustice.org
JOEL MINOR
Earthjustice
633 17th Street, Suite 1600
Denver, CO 80202
Telephone: (303) 996-9628
jminor@earthjustice.org
Counsel for Petitioners Sierra Club and Clean Air Council

ADAM KRON
Environmental Integrity Project
1000 Vermont Ave. NW, Suite 1100
Washington, DC 20005
Telephone: (202) 263-4451
akron@environmentalintegrity.org
Counsel for Petitioner Environmental Integrity Project

TABLE OF CONTENTS

Attachment 1

U.S. EPA, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; **Grant of Reconsideration and Partial Stay**, 82 Fed. Reg. 25,730 (June 5, 2017)

Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

D. Federalism and Indian Tribal Governments

A rule has implications for Federalism under Executive Order 13132 if it has a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. We have analyzed this rule under that Order and have determined that it is consistent with the fundamental federalism principles and preemption requirements described in Executive Order 13132.

Also, this rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it would not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes. If you believe this rule has implications for Federalism or Indian tribes, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

E. Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 (adjusted for inflation) or more in any one year. Though this rule would not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

F. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (42 U.S.C. 4321–4370f), and have made a preliminary determination that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves the establishment of a permanent safety zone on the navigable waters of Port Valdez, in the vicinity of the Valdez Spit. It is categorically excluded from further review in accordance with paragraph 34(g) of Figure 2–1 of Commandant Instruction M16475.lD. A Record of Environmental Consideration (REC) supporting this determination is available in the docket where indicated in the **ADDRESSES** section of this preamble.

G. Protest Activities

The Coast Guard respects the First Amendment rights of protesters. Protesters are asked to contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to coordinate protest activities so that your message can be received without jeopardizing the safety or security of people, places, or vessels.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C 1231; 50 U.S.C. 191; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add § 165.1713 to read as follows:

§ 165.1713 Safety Zone; City of Valdez July 4th Fireworks, Port Valdez; Valdez, AK.

(a) *Regulated area.* The following area is a permanent safety zone: All navigable waters of Port Valdez within a 200-yard radius from a position of 61°07′22″ N. and 146°21′13″ W. This includes the entrance to the Valdez small boat harbor.

(b) *Effective date.* This rule will be effective from 9:30 p.m. until 11:30 p.m. on July 4th of each year, or during the same time frame on specified rain dates of July 5th through July 8th of each year.

(c) *Definitions.* The following definitions apply to this section:

(1) The term ''designated representative'' means any Coast Guard commissioned, warrant or petty officer of the U. S. Coast Guard who has been designated by the COTP, Prince William Sound, to act on his or her behalf.

(2) The term ''official patrol vessel'' may consist of any Coast Guard, Coast Guard Auxiliary, state, or local law enforcement vessels assigned or approved by the COTP, Prince William Sound.

(d) *Regulations.* (1) The general regulations contained in 33 CFR 165.23, as well as the following regulations, apply.

(2) The safety zone is closed to all vessel traffic, except as may be permitted by the COTP or the designated representative during periods of enforcement.

(3) All persons and vessels shall comply with the instructions of the COTP or the designated representative. Upon being hailed by a U.S. Coast Guard vessel or other official patrol vessel by siren, radio, flashing light or other means, the operator of the vessel shall proceed as directed.

(4) Vessel operators desiring to enter or operate within the regulated area may request permission from the COTP via VHF Channel 16 or (907) 835–7205 (Prince William Sound Vessel Traffic Center) to request permission to do so.

(5) The Coast Guard will issue a Broadcast Notice to Mariners to advise mariners of the safety zone before and during the event.

(6) The COTP may be aided by other Federal, state, borough and local law enforcement officials in the enforcement of this regulation.

Dated: May 16, 2017.

J.T. Lally,

Commander, U.S. Coast Guard, Captain of the Port, Prince William Sound, Alaska.

[FR Doc. 2017–11572 Filed 6–2–17; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9963–40–OAR]

RIN 2060–AT63

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of reconsideration and partial stay.

SUMMARY: By a letter dated April 18, 2017, the Administrator announced the convening of a proceeding for reconsideration of the fugitive emission requirements at well sites and compressor station sites in the final rule, ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources,'' published in the **Federal Register** on June 3, 2016. In this action, the Environmental Protection Agency (EPA) is granting reconsideration of additional

requirements in that rule, specifically the well site pneumatic pumps standards and the requirements for certification by professional engineer. In addition, the EPA is staying for three months these rule requirements pending reconsideration.

DATES: This final rule is effective June 2, 2017. The action granting reconsideration is effective June 2, 2017. The stay of §§ 60.5393a(b) through (c), 60.5397a, 60.5410a(e)(2) through (5) and (j), 60.5411a(d), 60.5415a(h), 60.5420a(b)(7), (8), and (12), and (c)(15) through (17) is effective from June 2, 2017, until August 31, 2017.

FOR FURTHER INFORMATION CONTACT: Mr. Peter Tsirigotis, Sector Policies and Programs Division (D205–01), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (888) 627–7764; email address: *airaction@epa.gov.*

Electronic copies of this document are available on EPA's Web site at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.* Copies of this document are also available at *https://www.regulations.gov,* at Docket ID No. EPA–HQ–OAR–2010–0505.

SUPPLEMENTARY INFORMATION:

I. Background

On June 3, 2016, the EPA published a final rule titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule,'' 81 FR 35824 (June 3, 2016) (''2016 Rule''). The 2016 Rule establishes new source performance standards (NSPS) for greenhouse gas emissions and volatile organic compound (VOC) emissions from the oil and natural gas sector. This rule addresses, among other things, fugitive emissions at well sites and compressor station sites (''fugitive emissions requirements''), and emissions from pneumatic pumps. In addition, for a number of affected facilities (*i.e.,* centrifugal compressors, reciprocating compressors, pneumatic pumps, and storage vessels), the rule requires certification by a professional engineer of the closed vent system design and capacity, as well as any technical infeasibility determination relative to controlling pneumatic pumps at well sites. For further information on the 2016 Rule, see 81 FR 35824 (June 3, 2016).

On August 2, 2016, a number of interested parties submitted administrative petitions to the EPA seeking reconsideration of various aspects of the 2016 Rule pursuant to section 307(d)(7)(B) of the Clean Air Act (CAA) (42 U.S.C. 7607(d)(7)(B)).[1] Those petitions include numerous objections relative to the fugitive emissions requirements, well site pneumatic pump standards, and the requirements for certification by professional engineer. Under section 307(d)(7)(B) of the CAA, the Administrator shall convene a reconsideration proceeding if, in the Administrator's judgment, the petitioner raises an objection to a rule that was impracticable to raise during the comment period or if the grounds for the objection arose after the comment period but within the period for judicial review. In either case, the Administrator must also conclude that the objection is of central relevance to the outcome of the rule. The Administrator may stay the effectiveness of the rule for up to three months during such reconsideration.

In a letter dated April 18, 2017, based on the criteria in CAA section 307(d)(7)(B), the Administrator convened a proceeding for reconsideration of the following objections relative to the fugitive emissions requirements: (1) The applicability of the fugitive emissions requirements to low production well sites, and (2) the process and criteria for requesting and receiving approval for the use of an alternative means of emission limitations (AMEL) for purposes of compliance with the fugitive emissions requirements in the 2016 Rule.

The EPA had proposed to exempt low production well sites from the fugitive emissions requirements, believing the lower production associated with these wells would generally result in lower fugitive emissions. 80 FR 56639. However, the final rule differs significantly from what was proposed in that it requires these well sites to comply with the fugitive emissions requirements based on information and rationale not presented for public comment during the proposal stage. See 81 FR 35856 (''. . . well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components''). It was therefore impracticable to object to this new rationale during the public comment period.

The AMEL process and criteria were included in the 2016 Rule without having been proposed for notice and comment. The EPA added the AMEL provisions in the final rule with the intent of, among other goals, reducing compliance burdens for those sources that may already be reducing fugitive emissions in accordance with a state requirement or other program that is achieving reductions equivalent to those required by the 2016 Rule. These AMEL provisions were also added to encourage the development and use of innovative technology, in particular for fugitive emissions monitoring. 81 FR 35861. However, issues and questions raised in the administrative petitions for reconsideration (*e.g.,* who can apply for and who can use an approved AMEL) suggest that sources may have difficulty understanding and applying for AMEL.

Both issues described above, which relate directly to whether certain sources must implement the fugitive emissions requirements, are of central relevance to the outcome of the 2016 Rule for the reasons stated below. Fugitive emissions are a significant source of emissions for many industries, and the EPA has promulgated numerous NSPS specifically for reducing fugitive emissions, including 40 CFR part 60, subpart KKK (addressing VOC leaks from on-shore natural gas processing plants), as standalone rules. The fact that the EPA chose here to promulgate the well site and compressor station fugitive emissions requirements along with other standards in the 2016 Rule does not make these requirements any less important than the other fugitive emissions standards; rather, because of their importance, they are a significant component of the 2016 Rule. The issues described above are important as they determine the universe of affected facilities that must implement the fugitive emission requirements; as such, they are of central relevance to the outcome of the 2016 Rule. As stated in the April 18, 2017, letter, the EPA has convened an administrative proceeding for the reconsideration of the fugitive emissions requirements in response to these two objections.

II. Grant of Reconsideration of Additional Issues

Since issuing the April 18, 2017, letter, the EPA has identified objections to two other aspects of the 2016 Rule that meet the criteria for reconsideration under section 307(d)(7)(B) of the CAA. These objections relate to (1) the requirements for certification of closed vent system by professional engineer, and (2) the well site pneumatic pump standards.

A. Requirements for Certification of Closed Vent System by Professional Engineer

For closed vent systems used to comply with the emission standards for

[1] Copies of these petitions are included in the docket for the 2016 Rule, Docket ID No. EPA–HQ–OAR–2010–0505.

various equipment used in the oil and natural gas sector, the 2016 Rule requires certification by a professional engineer (PE) that a closed vent system design and capacity assessment was conducted under his or her direction or supervision and that the assessment and resulting report were conducted pursuant to the requirements of the 2016 Rule (''PE certification requirement''). Several petitioners for administrative reconsideration assert that the PE certification requirement was not proposed for notice and comment.[2] One petitioner notes that no costs associated with obtaining such certification were considered or provided for review during the proposal process.[3] The petitioner claims that there is no quantifiable benefit to the environment from this additional compliance demonstration requirement, while there is significant expense involved.[4]

Section 111 of the CAA requires that the EPA consider, among other factors, the cost associated with establishing a new source performance standard. See 111(a)(1) of the CAA. The statute is thus clear that cost is an important consideration in determining whether to impose a requirement. In finalizing the 2016 Rule, the EPA made clear that it viewed the PE certification requirement to be an important aspect of a number of performance standards in the that rule. The EPA acknowledges that it had not analyzed the costs associated with the PE certification requirement; therefore, it was impracticable for petitioners to provide meaningful comments during the comment period on whether the improved environmental performance this requirement may achieve justifies the associated costs and other compliance burden. This issue is of central relevance to the outcome of the 2016 Rule because the rule requires this PE certification for demonstrating compliance for a number of different standards, including the standards for centrifugal compressors, reciprocating compressors, pneumatic pumps, and storage vessels. For the reasons stated above, the EPA is granting reconsideration of the PE certification requirement.

B. Technical Infeasibility Determination (Well Site Pneumatic Pump Standards)

In the 2016 Rule, the EPA exempts a pneumatic pump at a well site from the emission reduction requirement if it is technically infeasible to route the pneumatic pump to a control device or a process. 81 FR 35850. However, the rule requires that such technical infeasibility be determined and certified by a ''qualified professional engineer'' as that term is defined in the final rule. During the proposal stage, the EPA did not propose or otherwise suggest exempting well site pneumatic pumps from emission control based on such certification. In fact, the technical infeasibility exemption itself was added during the final rule stage. Further, this certification requirement differs significantly from how the EPA has previously addressed another ''technical infeasibility'' issue encountered by this industry. Specifically, the oil and gas NSPS subpart OOOO, which was promulgated in 2012, exempts hydraulically fractured gas well completions from performing a reduced emission completion (REC) if it is not technically feasible to do so, and requires documentation and recordkeeping of the technical infeasibility. See 40 CFR 60.5375. The 2016 Rule extends the REC requirement and associated technical infeasibility exemption to hydraulically fractured oil well completions and requires more detailed documentation of technical infeasibility. Neither subpart OOOO nor the 2016 Rule require that REC technical infeasibility be certified by a qualified professional engineer, nor was such requirement proposed or otherwise raised during the public comment period for these rules. In light of the fact that the EPA had not proposed such certification requirement for pneumatic pumps, and how this requirement differs from the EPA's previous treatment of a similar issue as described above, one could not have anticipated that the 2016 Rule would finalize such certification requirement for pneumatic pumps in the 2016 Rule. Further, believing that ''circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location can be addressed in the site's design and construction,'' the EPA does not allow such exemption for new developments in the 2016 Rule. 40 CFR 60.5393a(b)(5); see also, 81 FR 35849. The 2016 Rule refers to such new developments as ''greenfield,'' which is defined as an ''entirely new construction.'' 40 CFR 60.5430a.

The provisions described above were included in the 2016 Rule without having been proposed for notice and comment, and numerous related objections and issues were raised in the reconsideration petitions. With respect to the requirement that technical infeasibility be certified by a professional engineer, petitioners raised the same issues as those for closed vent system certification discussed in section II.A. In addition, several petitions find the definition of greenfield unclear. For example, one petitioner questions whether the term ''new'' as used in this definition is synonymous to how that term is defined in section 111 of the CAA. Additional questions include whether a greenfield remains forever a greenfield, considering that site designs may change by the time that a new control or pump is installed (which may be years later). Petitioners also object to EPA's assumption that the technical infeasibility encountered at existing well sites can be addressed when ''new'' sites are developed. The issues described above dictate whether one must achieve the emission reduction required under the well site pneumatic pump standards, which were a major addition to the existing oil and gas NSPS regulations through promulgation of the 2016 Rule. Therefore, these issues are of central relevance to the outcome of the 2016 Rule.

As announced in the April 18, 2017, letter, and as further announced in this document, the Administrator has convened an administrative reconsideration proceeding. As part of the proceeding, the EPA will prepare a notice of proposed rulemaking that will provide the petitioners and the public an opportunity to comment on the rule requirements and associated issues identified above, as well as those for which reconsideration was granted in the April 18, 2017, letter. During the reconsideration proceeding, the EPA intends to look broadly at the entire 2016 Rule. For a copy of this letter and the administrative reconsideration petitions, please see Docket ID No. EPA–HQ–OAR–2010–0505.

III. Stay of Certain Provisions

By this document, in addition to the grant of reconsideration discussed in section II above, the EPA is staying the effectiveness of certain aspects of the 2016 Rule for three months pursuant to section 307(d)(7)(B) of the CAA pending reconsideration of the requirements and associated issues described above and in the April 18, 2017, letter. Specifically, the EPA is staying the effectiveness of the fugitive emissions requirements, the standards for pneumatic pumps at well sites, and the certification by a professional engineer requirements. As explained above, the low production well sites and AMEL issues under reconsideration determine the universe of sources that must implement the fugitive emissions requirements. The

[2] See Docket ID No. EPA–HQ–OAR–2010–0505–7682 and Docket ID No. EPA–HQ–OAR–2010–0505–7686.

[3] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[4] Id.

2016 Rule requires compliance with the closed vent system requirements, including certification by a professional engineer, in order to meet the emissions standards for a wide range of equipment (centrifugal compressors, reciprocating compressors, pneumatic pumps, and storage vessels); therefore, the issues relative to closed vent certification affect the ability of these equipment to comply with the 2016 Rule. The technical infeasibility exemption and the associated certification by professional engineer requirement, as well as the ''greenfield'' issues described above, dictate whether a source must comply with the emission reduction requirement for well site pneumatic pumps. In light of the uncertainties these issues generate regarding the application and/or implementation of the fugitive emissions requirements, the well site pneumatic pumps standards and the certification by professional engineers requirements, the EPA believes it is reasonable to stay the effectiveness of these requirements in the 2016 Rule, pending reconsideration. Therefore, pursuant to section 307(d)(7)(B) of the CAA, the EPA hereby stays the effectiveness of these requirements for three months.

This stay will remain in place until August 31, 2017.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping.

Dated: May 26, 2017.

E. Scott Pruitt,

Administrator.

■ For the reasons cited in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

Subpart OOOOa—[Amended]

■ 2. Section 60.5393a is amended by:
■ a. Staying paragraphs (b) and (c) from June 2, 2017, until August 31, 2017; and
■ b. Adding paragraph (f).

The addition reads as follows:

§ 60.5393a What GHG and VOC standards apply to pneumatic pump affected facilities?

* * * * *

(f) Pneumatic pumps at a well site are not subject to the requirements of paragraph (d) and (e) of this section from June 2, 2017, until August 31, 2017.

§ 60.5397a [Amended]

■ 3. Section 60.5397a is stayed from June 2, 2017, until August 31, 2017.
■ 4. Section 60.5410a is amended by:
■ a. Staying paragraphs (e)(2) through (5) from June 2, 2017, until August 31, 2017;
■ b. Adding paragraph (e)(8); and
■ c. Staying paragraph (j) from June 2, 2017, until August 31, 2017.

The addition reads as follows:

§ 60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

* * * * *

(e) * * *

(8) Pneumatic pump affected facilities at a well are not subject to the requirements of (e)(6) and (7) of this section from June 2, 2017, until August 31, 2017.

* * * * *

■ 5. Section 60.5411a is amended by:
■ a. Revising the introductory text;
■ b. Staying paragraph (d) from June 2, 2017, until August 31, 2017; and
■ c. Adding paragraph (e).

The revision and addition read as follows:

§ 60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps and storage vessels except as provided in paragraph (e) of this section.

* * * * *

(e) Pneumatic pump affected facilities at a well site are not subject to the requirements of paragraph (a) of this section from June 2, 2017, until August 31, 2017.

■ 6. Section 60.5415a is amended by:
■ a. Revising paragraph (b) introductory text and adding paragraph (b)(4); and
■ b. Staying paragraph (h) from June 2, 2017, until August 31, 2017.

The revision and addition read as follows:

§ 60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, and affected facilities at onshore natural gas processing plants?

* * * * *

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility, you must demonstrate continuous compliance according to paragraph (b)(3) of this section except as provided in paragraph (b)(4) of this section. For each centrifugal compressor affected facility, you also must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

* * * * *

(4) Pneumatic pump affected facilities at a well site are not subject to the requirements of paragraphs (b)(3) of this section from June 2, 2017, until August 31, 2017.

* * * * *

■ 7. Section 60.5416a is amended by revising the introductory text and adding paragraph (d) to read as follows:

§ 60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor, reciprocating compressor and pneumatic pump affected facilities, you must comply with the applicable requirements of paragraphs (a) through (c) of this section, except as provided in paragraph (d) of this section.

* * * * *

(d) Pneumatic pump affected facilities at a well site are not subject to the requirements of paragraphs (a) and (b) of this section from June 2, 2017, until August 31, 2017.

■ 8. Section 60.5420a is amended by:
■ a. Revising paragraph (b) introductory text;
■ b. Staying paragraphs (b)(7), (8), and (12) from June 2, 2017, until August 31, 2017;
■ c. Adding paragraph (b)(13); and
■ d. Staying paragraphs (c)(15) through (17) from June 2, 2017, until August 31, 2017.

The revision and addition read as follows:

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

* * * * *

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) and (12) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section, if applicable, except as provided in paragraph (b)(13) of this section. You must submit annual reports following the procedure specified in paragraph (b)(11) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) of this section, except as provided in paragraph (b)(13) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

* * * * *

(13) The collection of fugitive emissions components at a well site (as defined in § 60.5430a), the collection of fugitive emissions components at a compressor station (as defined in § 60.5430a), and pneumatic pump affected facilities at a well site (as defined in § 60.5365a(h)(2)) are not subject to the requirements of paragraph (b)(1) of this section from June 2, 2017, until August 31, 2017.

* * * * *

[FR Doc. 2017–11457 Filed 6–2–17; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 62

[EPA–R08–OAR–2017–0171; FRL–9963–21–Region 8]

Approval and Promulgation of State Plans for Designated Facilities and Pollutants: Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming; Negative Declarations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: With this direct final rule, the Environmental Protection Agency (EPA) is taking action to approve the negative declarations for several designated facility classes in various states of Region 8. First, the EPA is taking direct final action in approving the negative declarations for small municipal waste combustor (MWC) units submitted by the states of Colorado, Montana, North Dakota, South Dakota, and Wyoming. Second, the EPA is taking direct final action in approving the negative declarations for large MWC units submitted by the states of Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming. Third, the EPA is taking direct final action in approving the negative declarations for commercial industrial solid waste incineration (CISWI) units submitted by the states of Montana, South Dakota, Utah, and Wyoming. Fourth, the EPA is taking direct final action in approving the negative declarations for other solid waste incineration (OSWI) units submitted by the states of Montana, North Dakota, South Dakota, Utah, and Wyoming. Each state included in this action has notified the EPA in a letter of negative declaration that there are no existing designated facilities, of the source category specified in each particular letter of negative declaration, subject to the requirements of sections 111(d) and 129 of the Clean Air Act (CAA or the ''Act'') currently operating within the jurisdictional boundaries of their state. The EPA is accepting the negative declarations in accordance with sections 111(d) and 129(b) of the Act. This is a direct final action without prior notice and comment because the action is deemed noncontroversial.

DATES: This direct final rule is effective on August 4, 2017 without further notice, unless the EPA receives adverse written comments on or before July 5, 2017. If adverse comments are received, the EPA will publish a timely withdrawal of the direct final rule in the **Federal Register** informing the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R08–OAR–2017–0171 at *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov.* The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT: Gregory Lohrke, Air Program, U.S. Environmental Protection Agency (EPA), Region 8, Mail Code 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129, (303) 312–6396, *lohrke.gregory@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Why is EPA using a direct final rule?

The EPA is publishing this rule without prior proposal because the agency views this as a noncontroversial action and anticipates no adverse comments. However, in the Proposed Rules section of today's **Federal Register** publication, the EPA is publishing a separate document that will serve as the proposal to publish the negative declarations should relevant adverse comments be filed. This rule will be effective August 4, 2017 without further notice unless the agency receives relevant adverse comments by July 5, 2017.

If the EPA receives adverse comments, the EPA will publish a timely withdrawal in the **Federal Register** informing the public that this direct final rule will not take effect. The EPA will address all public comments in a subsequent final rule based on the proposed rule. The EPA will not institute a second comment period on this action. Any parties interested in commenting must do so at this time. Please note that if the EPA receives adverse comment on an amendment, paragraph, or section of this rule and if that provision may be severed from the remainder of the rule, the EPA may adopt as final those provisions of the rule that are not the subject of an adverse comment.

II. Background

The EPA's statutory authority for regulating new and existing solid waste incineration units is outlined in CAA sections 111 and 129. Section 129 of the

Attachment 2

U.S. EPA, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, **Final Rule**, 81 Fed. Reg. 35,824 (June 3, 2016) (excerpts)

FEDERAL REGISTER

Vol. 81 Friday,
No. 107 June 3, 2016

Part II

Environmental Protection Agency

40 CFR Part 60
Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9944–75–OAR]

RIN 2060–AS30

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the current new source performance standards (NSPS) and establishes new standards. Amendments to the current standards will improve implementation of the current NSPS. The new standards for the oil and natural gas source category set standards for both greenhouse gases (GHGs) and volatile organic compounds (VOC). Except for the implementation improvements, and the new standards for GHGs, these requirements do not change the requirements for operations covered by the current standards.

DATES: This final rule is effective on August 2, 2016.

The incorporation by reference (IBR) of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 2, 2016.

ADDRESSES: The Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2010–0505. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: For further information concerning this action, contact Ms. Amy Hambrick, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–0964; facsimile number: (919) 541–3470; email address: *hambrick.amy@epa.gov* or Ms. Lisa Thompson, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–9775; facsimile number: (919) 541–3470; email address: *thompson.lisa@epa.gov.* For other information concerning the EPA's Oil and Natural Gas Sector regulatory program, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 541–3470; email address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION: *Outline.* The information presented in this preamble is presented as follows:

I. Preamble Acronyms and Abbreviations

Several acronyms and terms are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

API American Petroleum Institute
bbl Barrel
boe Barrels of Oil Equivalent
BSER Best System of Emissions Reduction
BTEX Benzene, Toluene, Ethylbenzene and Xylenes
CAA Clean Air Act
CBI Confidential Business Information
CFR Code of Federal Regulations
CO_2 Eq. Carbon dioxide equivalent
DCO Document Control Officer
EIA Energy Information Administration
EPA Environmental Protection Agency
GHG Greenhouse Gases
GHGRP Greenhouse Gas Reporting Program
GOR Gas to Oil Ratio
HAP Hazardous Air Pollutants
LDAR Leak Detection and Repair
Mcf Thousand Cubic Feet
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act of 1995
OAQPS Office of Air Quality Planning and Standards
OGI Optical Gas Imaging
OMB Office of Management and Budget
PRA Paperwork Reduction Act
PTE Potential to Emit
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
scf Standard Cubic Feet
scfh Standard Cubic Feet per Hour
scfm Standard Cubic Feet per Minute
SO_2 Sulfur Dioxide
tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. General Information

A. Executive Summary

1. Purpose of This Regulatory Action

The Environmental Protection Agency (EPA) proposed amendments to the New Source Performance Standards (NSPS) at subpart OOOO and proposed new standards at subpart OOOOa on September 18, 2015 (80 FR 56593). The purpose of this action is to finalize both the amendments and the new standards with appropriate adjustments after full consideration of the comments received on the proposal. Prior to proposal, we pursued a structured engagement process with states and stakeholders. Prior to that process, we issued draft white papers addressing a range of technical issues and then solicited comments on the white papers from expert reviewers and the public.

These rules are designed to complement other federal actions as well as state regulations. In particular, the EPA worked closely with the Department of Interior's Bureau of Land Management (BLM) during development of this rulemaking in order to avoid conflicts in requirements between the NSPS and BLM's proposed rulemaking.[1] Additionally, we evaluated existing state and local programs when developing these federal standards and attempted, where possible, to limit potential conflicts with existing state and local requirements.

As discussed at proposal, prior to this final rule, the EPA had established standards for emissions of VOC and sulfur dioxide (SO_2) for several sources in the source category. In this action, the EPA finalizes standards at subpart OOOOa, based on our determination of the best system of emissions reduction (BSER) for reducing emissions of greenhouse gases (GHGs), specifically methane, as well as VOC across a variety of additional emission sources in the oil and natural gas source category (*i.e.,* production, processing, transmission, and storage). The EPA includes requirements for methane emissions in this action because methane is one of the six well-mixed gases in the definition of GHGs and the oil and natural gas source category is one of the country's largest industrial emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.

[1] 81 FR 6616, February 8, 2016, *Waste Prevention, Production Subject to Royalties, and Resource Conservation, Proposed Rule.*

In addition to finalizing standards for VOC and GHGs, the EPA is finalizing amendments to improve several aspects of the existing standards at 40 CFR part 60, subpart OOOO related to implementation. These improvements and the setting of standards for GHGs in the form of limitations on methane result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, NSPS (77 FR 49490) and on the September 13, 2013, amendments (78 FR 58416). These implementation improvements do not change the requirements for operations and equipment covered by the current standards at subpart OOOO.

2. Summary of 40 CFR Part 60, Subpart OOOOa Major Provisions

The final requirements include standards for GHG emissions (in the form of methane emission limitations) and standards for VOC emissions. The NSPS includes both VOC and GHG emission standards for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas source category. These emission sources include the following:

- Sources that are unregulated under the current NSPS at subpart OOOO (hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations);
- Sources that are currently regulated at subpart OOOO for VOC, but not for GHGs (hydraulically fractured gas well completions and equipment leaks at natural gas processing plants);
- Certain equipment that is used across the source category, for which the current NSPS at subpart OOOO regulates emissions of VOC from only a subset (pneumatic controllers, centrifugal compressors, and reciprocating compressors), with the exception of compressors located at well sites.

Table 1 below summarizes these sources and the final standards for GHGs (in the form of methane limitations) and VOC emissions. See sections V and VI of this preamble for further discussion.

TABLE 1—SUMMARY OF BSER AND FINAL SUBPART OOOOa STANDARDS FOR EMISSION SOURCES

Source	BSER	Final standards of performance for GHGs and VOC
Wet seal centrifugal compressors (except for those located at well sites)[2].	Capture and route to a control device	95 percent reduction.
Reciprocating compressors (except for those located at well sites)[2].	Regular replacement of rod packing (*i.e.*, approximately every 3 years).	Replace the rod packing on or before 26,000 hours of operation or 36 calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure.
Pneumatic controllers at natural gas processing plants.	Instrument air systems	Zero natural gas bleed rate.
Pneumatic controllers at locations other than natural gas processing plants.	Installation of low-bleed pneumatic controllers	Natural gas bleed rate no greater than 6 standard cubic feet per hour (scfh).
Pneumatic pumps at natural gas processing plants.	Instrument air systems in place of natural gas driven pumps.	Zero natural gas emissions.
Pneumatic pumps at well sites	Route to existing control device or process	95 percent control if there is an existing control or process on site. 95 percent control not required if (1) routed to an existing control that achieves less than 95 percent or (2) it is technically infeasible to route to the existing control device or process (non-greenfield sites only).
Well completions (subcategory 1: Non-wildcat and non-delineation wells).	Combination of Reduced Emission Completion (REC) and the use of a completion combustion device.	REC in combination with a completion combustion device; venting in lieu of combustion where combustion would present safety hazards. Initial flowback stage: Route to a storage vessel or completion vessel (frac tank, lined pit, or other vessel) and separator. Separation flowback stage: Route all salable gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an onsite fuel source or use for another useful purpose that a purchased fuel or raw material would serve. If technically infeasible to route recovered gas as specified above, recovered gas must be combusted. All liquids must be routed to a storage vessel or well completion vessel, collection system, or be re-injected into the well or another well. The operator is required to have a separator onsite during the entire flowback period.
Well completions (subcategory 2: Exploratory and delineation wells and low pressure wells).	Use of a completion combustion device	The operator is not required to have a separator onsite. Either: (1) Route all flowback to a completion combustion device with a continuous pilot flame; or (2) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device with a continuous pilot flame. For both options (1) and (2), combustion is not required in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways.
Fugitive emissions from well sites and compressor stations.	For well sites: Monitoring and repair based on semiannual monitoring using optical gas imaging (OGI)[3].	Monitoring and repair of fugitive emission components using OGI with Method 21 as an alternative at 500 parts per million (ppm).
	For compressor stations: Monitoring and repair based on quarterly monitoring using OGI.	A monitoring plan must be developed and implemented and repair of the sources of fugitive emissions must be completed within 30 days of finding fugitive emissions.

TABLE 1—SUMMARY OF BSER AND FINAL SUBPART OOOOa STANDARDS FOR EMISSION SOURCES—Continued

Source	BSER	Final standards of performance for GHGs and VOC
Equipment leaks at natural gas processing plants.	Leak detection and repair at 40 CFR part 60, subpart VVa level of control.	Follow requirements at NSPS part 60, subpart VVa level of control as in the 2012 NSPS.

Reconsiderationissues being addressed. As fully detailed in sections V and VI of this preamble and the Response to Comment (RTC) document, the EPA granted reconsideration of several issues raised in the administrative reconsideration petitions submitted on the 2012 NSPS and subsequent amendments (subpart OOOO). In this final rule, in addition to the new standards described above, the EPA includes certain amendments to the 2012 NSPS at subpart OOOO based on reconsideration of those issues. The amendments to the subpart OOOO requirements are effective on August 2, 2016 and, therefore, do not affect compliance activities completed prior to that date.

These provisions are: Requirements for storage vessel control device monitoring and testing; initial compliance requirements for a bypass device that could divert an emission stream away from a control device; recordkeeping requirements for repair logs for control devices failing a visible emissions test; clarification of the due date for the initial annual report; flare design and operation standards; leak detection and repair (LDAR) for open-ended valves or lines; the compliance period for LDAR for newly affected units; exemption to the notification requirement for reconstruction; disposal of carbon from control devices; the definition of capital expenditure; and continuous control device monitoring requirements for storage vessels and centrifugal compressor affected facilities. We are finalizing changes to address these issues to clarify the current NSPS requirements, improve implementation, and update procedures.

3. Costs and Benefits

The EPA has carefully reviewed the comments and additional data submitted on the costs and benefits associated with this rule. Our conclusion and responses are summarized in section IX of the preamble and addressed in greater detail in the Regulatory Impact Analysis (RIA) and RTC. The measures finalized in this action achieve reductions of GHG and VOC emissions through direct regulation and reduction of hazardous air pollutant (HAP) emissions as a co-benefit of reducing VOC emissions. The data show that these are cost-effective measures to reduce emissions and the rule's benefits outweigh these costs.

The EPA has estimated emissions reductions, benefits, and costs for 2 years of analysis: 2020 and 2025. Therefore, the emissions reductions, benefits, and costs by 2020 and 2025 (*i.e.,* including all emissions reductions, costs, and benefits in all years from 2016 to 2025) would be potentially significantly greater than the estimated emissions reductions, benefits, and costs provided within this rule. Actions taken to comply with the final NSPS are anticipated to prevent significant new emissions in 2020, including 300,000 tons of methane; 150,000 tons of VOC; and 1,900 tons of HAP. The emission reductions anticipated in 2025 are 510,000 tons of methane; 210,000 tons of VOC; and 3,900 tons of HAP. Using a 100-year global warming potential (GWP) of 25, the carbon dioxide-equivalent (CO_2 Eq.) methane emission reductions are estimated to be 6.9 million metric tons CO_2 Eq. in 2020 and 11 million metric tons CO_2 Eq. in 2025. The methane-related monetized climate benefits are estimated to be $360 million in 2020 and $690 million in 2025 using a 3-percent discount rate (model average).[4]

While the only benefits monetized for this rule are GHG-related climate benefits from methane reductions, the rule will also yield benefits from reductions in VOC and HAP emissions and from reductions in methane as a precursor to global background concentrations of tropospheric ozone. The EPA was unable to monetize the benefits of VOC reductions due to the difficulties in modeling the impacts with the current data available. A detailed discussion of these unquantified benefits appears in section IX of this preamble, as well as in the RIA available in the docket.

Several VOC that are commonly emitted in the oil and natural gas source category are HAP listed under Clean Air Act (CAA) section 112(b), including benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ''BTEX'') and n-hexane. These pollutants and any other HAP included in the VOC emissions controlled under the NSPS, including requirements for additional sources being finalized in this action, are controlled to the same degree. The co-benefit HAP reductions for the final measures are discussed in the RIA and in the technical support document (TSD), which are included in the public docket for this action.

The HAP reductions from these standards will be meaningful in local communities, as members of these communities and other stakeholders across the country have reported significant concerns to the EPA regarding potential adverse health effects resulting from exposure to HAP emitted from oil and natural gas operations. Importantly, these communities include disadvantaged populations.

The EPA estimates the total capital cost of the final NSPS will be $250 million in 2020 and $360 million in 2025. The estimate of total annualized engineering costs of the final NSPS is $390 million in 2020 and $640 million in 2025 when using a 7-percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the final NSPS are estimated to be $320 million in 2020 and $530 million in 2025, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf). These compliance cost estimates include revenues from recovered natural gas, as the EPA estimates that about 16 billion cubic feet in 2020 and 27 billion cubic feet in 2025 of natural gas will be recovered by implementing the NSPS.

Considering all the costs and benefits of this rule, including the revenues from

[2] See sections VI and VIII of this preamble for detailed discussion on emission sources.

[3] The final fugitive standards apply to low production wells. For the reasons discussed in section VI of the preamble, we are not finalizing the proposed exemption of low production wells from these requirements.

[4] We estimate methane benefits associated with four different values of a 1 ton methane reduction (model average at 2.5-percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this summary, we present the benefits associated with the model average at a 3-percent discount rate. However, we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section IX and in the RIA.

recovered natural gas that would otherwise be vented, this rule results in a net benefit. The quantified net benefits (the difference between monetized benefits and compliance costs) are estimated to be $35 million in 2020 and $170 million in 2025 using a 3-percent discount rate (model average) for climate benefits in both years.[5] All dollar amounts are in 2012 dollars.

B. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that the EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria found in the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section, your air permitting authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

C. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of the final action is available on the Internet through the Technology Transfer Network (TTN) Web site. Following signature by the Administrator, the EPA will post a copy of this final action at http://www3.epa.gov/airquality/oilandgas/actions.html. The TTN provides information and technology exchange in various areas of air pollution control. Additional information is also available at the same Web site.

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by August 2, 2016. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA further provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, EPA WJC, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

III. Background

A. Statutory Background

The EPA's authority for this rule is CAA section 111, which requires the EPA to first establish a list of source categories to be regulated under that section and then establish emission standards for new sources in that source category. Specifically, CAA section 111(b)(1)(A) requires that a source category be included on the list if, ''in [the EPA Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' This determination is commonly referred to as an ''endangerment finding'' and that phrase encompasses both of the ''causes or contributes significantly to'' component and the ''endanger public health or welfare'' component of the determination. Once a source category is listed, CAA section 111(b)(1)(B) requires that the EPA propose and then promulgate ''standards of performance'' for new sources in such source category. Other than the endangerment finding for listing the source category, CAA section 111(b) gives no direction or enumerated criteria concerning what constitutes a source category or what emission sources or pollutants from a given source category should be the subject of standards. Therefore, as long as the EPA makes the requisite endangerment finding for the source category to be listed, CAA section 111 leaves the EPA with the authority and discretion to define the source category, determine the pollutants for which standards should be developed, and identify the emission sources within the source category for which standards of performance should be established.

CAA section 111(a)(1) defines ''a standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' This definition makes

[5] Figures may not sum due to rounding.

storm surges.'' [36] Also, because of the inertia of the oceans, sea level rise will continue for centuries after GHG concentrations have stabilized (though reducing GHG emissions will slow the rate of sea level rise and, therefore, reduce the associated risks and impacts). Additionally, there is a threshold temperature above which the Greenland ice sheet will be committed to inevitable melting: According to the NCA3, some recent research has suggested that even present day CO_2 levels could be sufficient to exceed that threshold.

In general, climate change impacts are expected to be unevenly distributed across different regions of the United States and have a greater impact on certain populations, such as indigenous peoples and the poor. The NCA3 finds climate change impacts such as the rapid pace of temperature rise, coastal erosion, and inundation related to sea level rise and storms, ice and snow melt, and permafrost thaw are affecting indigenous people in the United States. Particularly in Alaska, critical infrastructure and traditional livelihoods are threatened by climate change and, ''[i]n parts of Alaska, Louisiana, the Pacific Islands, and other coastal locations, climate change impacts (through erosion and inundation) are so severe that some communities are already relocating from historical homelands to which their traditions and cultural identities are tied.'' [37] The IPCC AR5 notes, ''Climate-related hazards exacerbate other stressors, often with negative outcomes for livelihoods, especially for people living in poverty (high confidence). Climate-related hazards affect poor people's lives directly through impacts on livelihoods, reductions in crop yields, or destruction of homes and indirectly through, for example, increased food prices and food insecurity.'' [38]

The impacts of climate change outside the United States, as also pointed out in the 2009 Endangerment Finding, will also have relevant consequences on the United States and our citizens. The NRC Climate and Social Stress assessment concluded that it is prudent to expect that some climate events ''will produce consequences that exceed the capacity of the affected societies or global systems to manage and that have global security implications serious enough to compel international response.'' The NRC National Security Implications assessment recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats.

In addition to future impacts, the NCA3 emphasizes that climate change driven by manmade emissions of GHGs is already happening now and that it is currently having effects in the United States. According to the IPCC AR5 and the NCA3, there are a number of climate-related changes that have been observed recently, and these changes are projected to accelerate in the future. The planet warmed about 0.85 °Celsius (1.5 °Fahrenheit) from 1880 to 2012. It is extremely likely (greater than 95-percent probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (greater than 66-percent probability) that human influence has more than doubled the probability of occurrence of heat waves in some locations. In the Northern Hemisphere, the last 30 years were likely the warmest 30 year period of the last 1,400 years. United States average temperatures have similarly increased by 1.3° to 1.9 °F since 1895, with most of that increase occurring since 1970. Global sea levels rose 0.19 meters (7.5 inches) from 1901 to 2010. Contributing to this rise was the warming of the oceans and melting of land ice. It is likely that 275 gigatons per year of ice melted from land glaciers (not including ice sheets) since 1993, and that the rate of loss of ice from the Greenland and Antarctic ice sheets increased substantially in recent years, to 215 gigatons per year and 147 gigatons per year, respectively, since 2002. For context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 millimeter (mm). Annual mean Arctic sea ice has been declining at 3.5 to 4.1 percent per decade, and Northern Hemisphere snow cover extent has decreased at about 1.6 percent per decade for March and 11.7 percent per decade for June. Permafrost temperatures have increased in most regions since the 1980s by up to 3 °Celsius (5.4 °Fahrenheit) in parts of northern Alaska. Winter storm frequency and intensity have both increased in the Northern Hemisphere. The NCA3 states that the increases in the severity or frequency of some types of extreme weather and climate events in recent decades can affect energy production and delivery, causing supply disruptions, and compromise other essential infrastructure such as water and transportation systems.

In addition to the changes documented in the assessment literature, there have been other climate milestones of note. According to the National Oceanic and Atmospheric Administration (NOAA), atmospheric methane concentrations in 2014 were about 1,823 parts per billion, 150 percent higher than methane concentrations were in the year 1750. After a few years of nearly stable concentrations from 1999 to 2006, methane concentrations have resumed increasing at about 5 parts per billion per year. Concentrations today are likely higher than they have been for at least the past 800,000 years. Arctic sea ice has continued to decline, with September of 2012 marking a new record low in terms of Arctic sea ice extent, 40 percent below the 1979 to 2000 median. Sea level has continued to rise at a rate of 3.2 mm per year (1.3 inches/decade) since satellite observations started in 1993, more than twice the average rate of rise in the 20th century prior to 1993.[39] Also, 2015 was the warmest year globally in the modern global surface temperature record, going back to 1880, breaking the record previously held by 2014; this now means that the last 15 years have been 15 of the 16 warmest years on record.[40]

These assessments and observed changes make it clear that reducing emissions of GHGs across the globe is necessary in order to avoid the worst impacts of climate change and underscore the urgency of reducing emissions now. The NRC Committee on America's Climate Choices listed a number of reasons ''why it is imprudent to delay actions that at least begin the process of substantially reducing emissions.'' [41] For example:

- The faster emissions are reduced, the lower the risks posed by climate change. Delays in reducing emissions could commit the planet to a wide range

[36] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* United States Global Change Research Program, p. 9.

[37] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* United States Global Change Research Program, p. 17.

[38] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, p. 796.

[39] Blunden, J., and D.S. Arndt, Eds., 2015: State of the Climate in 2014. Bull. Amer. Meteor. Soc., 96 (7), S1–S267.

[40] *http://www.ncdc.noaa.gov/sotc/global/201513.*

[41] NRC, 2011: *America's Climate Choices,* The National Academies Press.

of adverse impacts, especially if the sensitivity of the climate to GHGs is on the higher end of the estimated range.

• Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of GHG emissions do not fully manifest themselves for decades and, once manifested, many of these changes will persist for hundreds or even thousands of years.

• In the committee's judgment, the risks associated with doing business as usual are a much greater concern than the risks associated with engaging in strong response efforts.

Methane is also a precursor to ground-level ozone, which can cause a number of harmful effects on health and the environment (see section IV.B.2 of this preamble). Additionally, ozone is a short-lived climate forcer that contributes to global warming. In remote areas, methane is a dominant precursor to tropospheric ozone formation.[42] Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane.[43] Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future.[44] Unlike NO_X and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime compared to these other ozone precursors.[45] Reducing methane emissions, therefore, will contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects.[46 47 48] The benefits of such reductions are global and occur in both urban and rural areas.

2. VOC

Many VOC can be classified as HAP (*e.g.,* benzene[49]) which can lead to a variety of health concerns such as cancer and noncancer illnesses (*e.g.,* respiratory, neurological). Further, VOC are one of the key precursors in the formation of ozone. Tropospheric, or ground-level, ozone is formed through reactions of VOC and NO_X in the presence of sunlight. Ozone formation can be controlled to some extent through reductions in emissions of ozone precursors VOC and NO_X. A significantly expanded body of scientific evidence shows that ozone can cause a number of harmful effects on health and the environment. Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation. For people with lung diseases such as asthma and chronic obstructive pulmonary disease (COPD), these effects can lead to emergency room visits and hospital admissions. Studies have also found that ozone exposure is likely to cause premature death from lung or heart diseases. In addition, evidence indicates that long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma. People most at risk from breathing air containing ozone include: Children; people with asthma and other respiratory diseases; older adults; and people who are active outdoors, especially outdoor workers. An estimated 25.9 million people have asthma in the United States, including almost 7.1 million children. Asthma disproportionately affects children, families with lower incomes, and minorities, including Puerto Ricans, Native Americans/Alaska Natives, and African-Americans.[50]

Scientific evidence also shows that repeated exposure to ozone can reduce growth and have other harmful effects on sensitive plants and trees. These types of effects have the potential to impact ecosystems and the benefits they provide.

3. SO_2

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for asthmatics at elevated ventilation rates (*e.g.,* while exercising or playing).

Studies also show an association between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

SO_2 in the air can also damage the leaves of plants, decrease their ability to produce food—photosynthesis—and decrease their growth. In addition to directly affecting plants, SO_2, when deposited on land and in estuaries, lakes, and streams, can acidify sensitive ecosystems resulting in a range of harmful indirect effects on plants, soils, water quality, and fish and wildlife (*e.g.,* changes in biodiversity and loss of habitat, reduced tree growth, loss of fish species). Sulfur deposition to waterways also plays a causal role in the methylation of mercury.[51]

C. GHGs, VOC and SO_2 Emissions From the Oil and Natural Gas Source Category

The previous section explains how GHGs, VOCs, and SO_2 emissions are ''air pollution'' that may reasonably be anticipated to endanger public health and welfare. This section provides estimated emissions of these substances from the oil and natural gas source category.

1. Methane Emissions in the United States and From the Oil and Natural Gas Industry

The GHGs addressed by the 2009 Endangerment Finding consist of six well-mixed gases, including methane. For the analysis supporting this regulation, we used the methane 100-year GWP of 25 to be consistent with and comparable to key Agency emission quantification programs such as the Inventory of United States Greenhouse Gas Emissions and Sinks (GHG Inventory), and the GHGRP.[52] The use of the 100-year GWP of 25 for methane value is currently required by the United Nations Framework Convention on Climate Change (UNFCCC) for reporting of national inventories, such as the United States GHG Inventory.

[42] U.S. EPA. 2013. ''Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final Report).'' EPA–600–R–10–076F. National Center for Environmental Assessment—RTP Division. Available at *http://www.epa.gov/ncea/isa/*.

[43] Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Pg. 680.

[44] *Ibid.*

[45] *Ibid.*

[46] West, J.J., Fiore, A.M. 2005. ''Management of tropospheric ozone by reducing methane emissions.'' *Environ. Sci. Technol.* 39:4685–4691.

[47] Anenberg, S.C., et al. 2009. ''Intercontinental impacts of ozone pollution on human mortality,'' *Environ. Sci. & Technol.* 43: 6482–6487.

[48] Sarofim, M.C., Waldhoff, S.T., Anenberg, S.C. 2015. ''Valuing the Ozone-Related Health Benefits of Methane Emission Controls,'' *Environ. Resource Econ.* DOI 10.1007/s10640–015–9937–6.

[49] Benzene IRIS Assessment: *https://cfpub.epa.gov/ncea/iris2/chemicalLanding.cfm?substance_nmbr=276.*

[50] National Health Interview Survey (NHIS) Data, 2011. *http://www.cdc.gov/asthma/nhis/2011/data.htm.*

[51] U.S. EPA. Intergrated Science Assessment (ISA) for Oxides of Nitrogen and Sulfur Ecological Criteria (2008 Final Report). U.S. Envieronmental Protection Agency, Washington, DC, EPA/600/R–08/082F, 2008.

[52] See, for example, Table A–1 to subpart A of 40 CFR part 98.

that we have on the low emission rates of piston pumps, we are not establishing requirements for them in this final rule.

We note that our best available emissions data for diaphragm pumps, as discussed in the TSD, indicates that the emission rate ranges from about 20 to 22 scf/hr during operation of a diaphragm pump. Based on our analysis of this data, we do not believe exclusion of diaphragm pumps from the definition of a pneumatic pump affected facility is warranted. As a result, we are retaining requirements for diaphragm pumps in the final rule.

2. Pneumatic Pumps Located in the Gathering and Boosting and Transmission and Storage Segments

We received comment that pneumatic pumps located in the transmission and storage segment generally have very low emissions. Similar to the arguments presented above for piston pumps, commenters contend that these low emission rate pumps should not be subjected to the final rule. In response to these comments, we reviewed our available information used in the proposed rule TSD to estimate the number of pneumatic pumps and the emission rates of these pumps in all segments of the oil and natural gas sector. In the TSD for the final rule, we noted that neither the GHGRP nor the GHG Inventory include data about pneumatic pumps or their emission rates in the natural gas transmission and storage segment. Because we currently have no reliable source of information indicating the prevalence of use of pneumatic pumps in this segment, nor what their emission rates would be if they are used, we are not finalizing pneumatic pump requirements for the transmission and storage segment at this time.

We also reviewed the available GHGRP and GHG Inventory data for pneumatic pumps, which was limited to the production segment. We consider the production segment to include both well sites and the gathering and boosting segment. Our available data indicate that pneumatic pumps are used at well sites as well as emission data for those pumps, but are silent on the prevalence of use of pneumatic pumps in the gathering and boosting segment, and what their emission rates would be if they are used. As with pneumatic pumps in the transmission and storage segment, we are not finalizing pneumatic pump requirements for the gathering and boosting segments at this time because of the lack of information in the record to support finalizing requirements for these pumps.

We note that the EPA is currently conducting a formal process to gather additional data on existing sources in the oil and natural gas sector. We believe that this data collection effort will provide additional information on the use and emissions of pneumatic pumps in the transmission and storage segment and gathering and boosting segment. Once we have obtained and analyzed these data, we will be better equipped to determine whether regulation of pneumatic pumps in the transmission and storage segment and gathering and boosting segment is warranted. See section III.E for more detail regarding the EPA's information collection request for existing sources.

3. Technical Infeasibility

We agree with comments that there may be circumstances, such as insufficient pressure or control device capacity, where it is technically infeasible to capture and route pneumatic pump emissions to a control device or process, and we have made changes in the final rule to include an exemption for these instances. The owner or operator must maintain records of an engineering evaluation and certification providing the basis for the determination that it is technically infeasible to meet the rule requirements. The rule does not allow the operator to claim the technical infeasibility exemption for a pneumatic pump affected facility at a greenfield site (defined as a site, other than a natural gas processing plant, which is entirely new construction), where circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location can be addressed in the site's design and construction.

4. Efficiency of Existing Control Devices

As noted above, we are finalizing emission standards for new, modified, and reconstructed natural gas-driven diaphragm pumps located at well sites requiring emissions be reduced by 95 percent if either a control device or the ability to route to a process is already available onsite. In setting this requirement, the EPA recognizes that there may not be a control device or process available onsite. Our analysis shows that it is not cost-effective to require the owner or operator of a pneumatic pump affected facility to install a new control device or process onsite to capture emissions. In those instances, the pneumatic pump affected facility is not subject to the emission reduction provisions of the final rule.

Commenters have also raised concerns, and we agree, that the control device available onsite may not be able to achieve a 95 percent emission reduction. We evaluated whether this requirement should only be triggered when a NSPS subpart OOOO or OOOOa compliant control device was onsite, which would alleviate the control efficiency concern raised by commenters. However, the EPA is concerned that significant emissions reductions would be lost as a result of limiting the required type of equipment that must be used to control pneumatic pump emissions to only those that are designed to achieve 95 percent emission reductions. We are not requiring the owner or operator to install a new control device on site that is capable of meeting a 95 percent reduction nor are we requiring that the existing control device be retrofitted to enable it to meet the 95 percent reduction requirement. However, we are requiring that the owner or operator of a pneumatic pump affected facility at well sites to route the emissions to an existing control device even if it achieves a level of emissions reduction less than 95 percent. In those instances, the owner or operator must maintain records demonstrating the percentage reduction that the control device is designed to achieve. In this way, the final rule will achieve emission reductions with regard to pneumatic pump affected facilities even if the only available control device on site cannot achieve a 95 percent reduction.

5. Compliance Requirements

In response to concerns about applicability of subpart OOOO or OOOOa compliance requirements, the EPA has clarified our intent in the final rule that existing control devices that are not already subject to subparts OOOO or OOOOa compliance requirements (*i.e.,* control devices that are subject to other federal or state compliance requirements) are not subject to the performance specifications, performance testing, and monitoring requirements in this rule solely because they are controlling pneumatic pump emissions. We believe that control devices covered by other federal, state, or other regulations would be subject to compliance requirements under those provisions and, therefore, we have reasonable assurance that the devices will perform adequately, and we do not need to include existing controls that are not already covered by subparts OOOO and OOOOa under the compliance requirements for these subparts.

6. Cost Analysis

In response to commenters' concerns that the costs were underestimated for compliance with the pneumatic pump performing a REC is technically infeasible for these wells.

To meet the definition of low pressure well, the well must satisfy any of the criteria above. We have revised the definition in the regulatory text to reflect this change. Section VIII, the RTC document, the TSD, and other materials available in the docket provide more discussion of these topics.

5. Timing of Initial Compliance

The EPA proposed the well completion requirements that, if finalized, would apply to both oil and gas well completions using hydraulic fracturing. In the 2012 NSPS, we provided a phase-in approach in the gas well completion requirements due to the concern with insufficient REC and trained personnel if REC were required immediately for all gas well completions. However, we did not provide the same in this proposal on the assumption that the supplies of REC equipment and trained personnel have caught up with the demand and, therefore, are no longer an issue. While some commenters agreed, other commenters indicated that the proposed rule, which would dramatically increase the number of well completions subject to the NSPS, would lead to REC equipment shortages. One commenter estimated that it would take at least 6 months to obtain the necessary equipment, while another commenter estimated that it would take 24 months. One commenter noted that owners and operators have been drilling wells, but delaying completion, due to the current economic conditions affecting the industry, causing a suppressed equipment demand. Finally, one state regulatory agency recommended extending the compliance period to 120 days to allow sufficient time to contract for the necessary completion equipment.

After reviewing the comments, we agree that some owners and operators may have difficulty complying with the REC requirements in the final rule in the near term due to the unavailability of REC equipment. Although REC equipment suppliers have increased production to meet the demand for gas well completions under subpart OOOO, the affected facility under subpart OOOOa includes both gas and oil wells and will more than double the number of wells requiring REC equipment over subpart OOOO. We believe this demand will likely lead to a short-term shortage of REC equipment. However, based on the prior experience, we believe that suppliers have both the capability and incentive to catch up with the demand quickly, as opposed to the longer terms suggested by the commenters; they likely already stepped up production since this rule was proposed last year in anticipation of the impending increase in demand. In light of the above, the final rule provides a phase-in approach that would allow a quick build-up of the REC supplies in the near term. Specifically, for subcategory 1 oil wells, the final rule requires combustion for well completions conducted before November 30, 2016 and REC if technically feasible for well completions conducted thereafter. For subcategory 2 and low pressure oil wells, the final rule requires combustion during well completion, which is the same as that required for completion of subcategory 2 and low pressure gas well in the 2012 NSPS. For gas well completions, which are already subject to well completion requirements in the 2012 NSPS, the requirements remain the same.

F. Fugitive Emissions From Well Sites and Compressor Stations

For fugitive emissions requirements for the source category, three principles or aims directed our efforts. The first aim was to produce a consistent and accountable program for a source to use to identify and repair fugitive emissions at well sites and compressor stations. A second aim was to provide an opportunity for companies to design and implement their own fugitive emissions monitoring and repair programs. The third aim was to focus the fugitive emissions monitoring and repair program on components from which we expected the greatest emissions, with consideration of appropriate exemptions. The fourth aim was to establish a program that would complement other programs currently in place. With these principles in mind, we proposed a detailed monitoring plan; semiannual requirements using OGI technology for monitoring to find and repair sources of fugitive emissions, which we had identified as the BSER; a shifting monitoring schedule based on performance; a 15-day timeframe for repairing and resurveying leaks; and an exemption for low production wells.

The public comment process helped us to identify additional information to consider and provided an opportunity to refine the standards proposed. Commenters specifically identified concerns with the definition of modification for well sites and compressor stations, the monitoring plan, the fluctuating survey frequency, the overlap with state and federal requirements, use of emerging monitoring technologies, the initial compliance timeframe, and the relationship between production level and fugitive emissions.

In this final rule, based on our consideration of the comments received and other relevant information, we have made changes to the proposed standards for fugitive emissions from well sites and compressor stations. The final rule refines the monitoring program requirements while still achieving the main goals. Below we describe the significant changes since proposal for specific topics related to fugitive emissions and our rationale for these changes. For additional details, please refer to section VIII, the TSD, and the RTC supporting documentation in the public docket.

1. Fugitive Emissions From Well Sites

a. Monitoring Frequency

In conjunction with semiannual monitoring, the EPA co-proposed annual monitoring and solicited comment on the availability of trained OGI contractors and OGI instrumentation. 80 FR 56637, September 18, 2015. Commenters provided numerous comments and data regarding annual, semiannual and quarterly monitoring surveys. These comments largely focused on the cost, effectiveness, and feasibility of the different program frequencies. The EPA evaluated these comments and information, as well as certain production segment equipment counts from the 2016 public review draft GHG Inventory, which were developed from the data reported to the GHGRP. Based on the above information, the EPA updated its proposal assumptions on equipment counts per well site to use data from the 2016 public review draft update. This resulted in changes to the well site model plant. Specifically, the equipment count for meters/piping at a gas well site increased from 1 to 3, which tripled the component counts from meters/piping at these sites. In addition, the EPA developed a third model plant to represent associated gas well sites. This category includes wells with GOR between 300 and 100,000 standard cubic feet per barrel (scf/bbl), and the model plant is assumed to have the same component counts as the model oil well site, as well as components associated with meters/piping. The EPA used this information to re-evaluate the control options for annual, semiannual and quarterly monitoring. As shown in the TSD, the control cost, using OGI, based on quarterly monitoring is not cost-effective, while both semiannual and annual monitoring remain cost-effective for reducing GHG (in the form of methane) and VOC emissions. Because control costs for both semiannual and annual monitoring are cost-effective, we evaluated the difference in emissions reductions between the two monitoring frequencies and concluded that semiannual monitoring would achieve greater emissions reductions. Therefore, the EPA is finalizing the proposed semiannual monitoring frequency. Please see the RTC document in the public docket for further discussion.[86] Even though the EPA has determined that semi-annual surveys for well sites is the BSER under this NSPS, this does not preclude the EPA from taking a different approach in the future, including requiring more frequent monitoring (*e.g.,* quarterly).

b. Low Production Well Sites

The EPA proposed to exclude low production well sites (*i.e.,* well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the fugitive emissions monitoring and repair requirements for well sites. As we explained in the preamble to the proposed rule, we believed that these wells are mostly owned by small businesses and that fugitive emissions associated with these wells are generally low. 80 FR 56639, September 18, 2015. We were concerned about the burden on small businesses, in particular, where there may be little emission reduction to be achieved. Id. We specifically requested comment on the proposed exclusion and the appropriateness of the 15 boe per day threshold. We also requested data that would confirm that low production sites have low GHG and VOC fugitive emissions.

Several commenters indicated that low production well sites should be exempt from fugitive emissions monitoring and that the 15 boe per day threshold averaged over the first 30 days of production is appropriate for the exemption, however, commenters did not provide data. Other commenters indicated that the low production well sites exemption would not benefit small businesses since these types of wells would not be economical to operate and few operators, if any, would operate new well sites that average 15 boe per day.

Several commenters stated that the EPA should not exempt low production well sites because they are still a part of the cumulative emissions that would impact the environment. One commenter indicated that low production well sites have the potential to emit high fugitive emissions. Another commenter stated that low production well sites should be required to perform fugitive emissions monitoring at a quarterly or monthly frequency. One commenter provided an estimate of low producing gas and oil wells that indicated that a significant number of wells would be excluded from fugitive emissions monitoring.

Based on the data from DrillingInfo, 30 percent of natural gas wells are low production wells, and 43 percent of all oil wells are low production wells. The EPA believes that low production well sites have the same type of equipment (*e.g.,* separators, storage vessels) and components (*e.g.,* valves, flanges) as production well sites with production greater than 15 boe per day. Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site. This would indicate that the emissions from low production well sites could be similar to that of non-low production well sites. We also believe that this type of well may be developed for leasing purposes but is typically unmanned and not visited as often as other well sites that would allow fugitive emissions to go undetected. We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions other than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites because the type of equipment and the well pressures are more than likely the same. In discussions with us, stakeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

Based on these considerations and, in particular, the large number of low production wells and the similarities between well sites with production greater than 15 boe per day and low production well sites in terms of the components that could leak and the associated emissions, we are not exempting low production well sites from the fugitive emissions monitoring program. Therefore, the collection of fugitive emissions components at all new, modified or reconstructed well sites is an affected facility and must meet the requirements of the fugitive emissions monitoring program.

c. Monitoring Using Method 21

The EPA's analysis for the proposed rule found OGI to be more cost-effective at detecting fugitive emissions than the traditional protocol for that purpose, Method 21, and the EPA, therefore, identified OGI as the BSER for monitoring fugitive emissions at well sites. See 80 FR 56636, September 18, 2015. The EPA solicited comment on whether to allow Method 21 as an alternative fugitive emissions monitoring method to OGI. 80 FR 56638, September 18, 2015. We also solicited comment on the repair threshold for components that are found to have fugitive emissions using Method 21. *Id.*

Numerous industry, state, and environmental commenters indicated that Method 21 is preferred or should be allowed as an alternative to OGI, citing availability, costs, and training associated with OGI.

Several commenters indicated that the EPA should set the Method 21 fugitive emissions repair threshold at 10,000 ppm, the level at which our recent work indicates that fugitive emissions are generally detectable using OGI instrumentation provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. 80 FR 56635, September 18, 2015. Some commenters stated that the repair threshold should be 500 ppm to achieve a high level of fugitive emission reductions while other commenters state that a 500 ppm repair threshold would target fugitive emissions that would not provide meaningful reductions.

The issue of the repair threshold when Method 21 is used is a critical decision. As discussed in the preamble to the proposed rule, Method 21, at an appropriate repair threshold, is capable of achieving the same or better emission reductions as OGI. However, at proposal, we determined that Method 21 was not cost-effective at a semiannual monitoring frequency with a repair threshold of 500 ppm.

While we agree with the importance of allowing the use of Method 21 as an alternative, we need to ensure that its use does not result in fewer emissions reductions than what would otherwise be achieved using OGI, which is the BSER based on our analysis. Available data show that OGI can detect fugitive emissions at a concentration of at least 10,000 ppm when restricting its use during certain environmental conditions

[86] See EPA docket ID No. EPA–HQ–OAR–2010–0505.

3. Certification of Technical Infeasibility of Connecting a Pneumatic Pump to an Existing Control Device

In response to comment, the final rule requires that a new, modified, or reconstructed pneumatic pump be routed to an existing control device or process onsite, unless the owner or operator obtains a certification that it is technically infeasible to do so. The EPA understands that some factors such as capacity of the existing control device and back pressure on the exhaust of the pneumatic pump imposed by the closed vent system and control device can contribute to infeasibility of routing a pneumatic pump to an existing control device onsite. Due to the various scenarios that could make routing a pneumatic pump to an onsite control device or process technically infeasible, we do not think we could prescribe a specific set of criteria or factors that must be considered for making such determination that could capture all such circumstances. However, we want to ensure that the owner or operator has effectively assessed these factors before making a claim of infeasibility. To that end, we have included provisions in the final rule to require certification by a qualified professional engineer of such technical infeasibility. In addition, we are requiring that the owner or operator maintain records of that certification for a period of five years.

4. Professional Engineer Design of Closed Vent Systems

It is the EPA's experience, through site inspections and interaction with the states, that closed vent systems and control devices for storage vessels and other emission sources often suffer from improper design or inadequate capacity that results in emissions not reaching the control device and/or the control device being overwhelmed by the volume of emissions. Either of these conditions can seriously compromise emissions control and can render the system ineffective. We also discussed the issue in the September 2015 Compliance Alert ''EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities'' (See *https://www.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf*).

We believe it is important that owners and operators make real efforts to provide for proper design of these systems to ensure that all the emissions routed to the control device reach the control device and that the control device is sized and operated to result in proper control. As a result, we have included in the final rule provisions for certification by a qualified professional engineer that the closed vent system is properly designed to ensure that all emissions from the unit being controlled in fact reach the control device and allow for proper control.

Although the final rule does not include requirements for specific criteria for proper design, the EPA believes there are certain minimum design criteria that should be considered to ensure that the closed vent and control device system are designed to meet the requirements of the rule; *i.e.,* the closed vent system must be capable of routing all gases, vapors, and fumes emitted from the affected facility to a control device or to a process that meets the requirements of the rule.

Furthermore, because other emissions may be collected into the closed vent system and routed to the control device, these design criteria include consideration of the contribution of these additional emissions to ensure proper sizing and operation. The minimum design elements include, but are not limited to, based on site-specific considerations:

1. Review of the Control Technologies to be Used to Comply with §§ 60.5380a and 60.5395a.

2. Closed Vent System Considerations:

a. Piping—

i. Size (include all emissions, not just affected facility);

ii. Back pressure, including low points which collect liquids;

iii. Pressure losses; and

iv. Bypasses and pressure release points.

3. Affected Facility Considerations:

a. Peak Flow from affected facility, including flash emissions, if applicable; and

b. Bypasses, pressure release points.

4. Control Device Considerations:

a. Maximum volumetric flow rate based on peak flow, and

b. Ability to handle future gas flow.

K. Provision for Equivalency Determinations

In recent years, certain states have developed programs to control various oil and gas emission sources in their own states. Due to the differences in the sources covered and the requirements, determining equivalency through direct comparison of the various state programs with the NSPS has proven to be difficult. We also did not find that any state program as a whole would reflect what we have identified as the BSERs for all emissions sources covered by the NSPS. In any event, federal standards are necessary to ensure that emissions from the oil and natural gas industry are controlled nationwide.

However, depending on the applicable state requirements, certain owners and operators may achieve equivalent or more emission reduction from their affected source(s) than the required reduction under the NSPS by complying with their state requirements. States may adopt and enforce standards or limitations that are more stringent than the NSPS. See CAA section 116 and the EPA's regulations at 40 CFR 60.10(a). For states that are being proactive in addressing emissions from the oil and natural gas industry, it is important that the NSPS complement such effort. Therefore, in the final rule, through the process described in section VI.F.1.i for emerging technology, owners and operators may also submit an application requesting that the EPA approve certain state requirement as ''alternative means of emission limitations'' under the NSPS for their affected facilities. The application would include a demonstration that emission reduction achieved under the state requirement(s) is at least equivalent to the emission reduction achieved under the NSPS standards for a given affected facility. Consistent with section 111(h)(3), any application will be publicly noticed, which the EPA intends to provide within six months after receiving a complete application, including all required information for evaluation. The EPA will provide an opportunity for public hearing on the application and on intended action the EPA might take. The EPA intends to make a final determination within six months after the close of the public comment period. The EPA will also publish its determination in the **Federal Register**.

VII. Prevention of Significant Deterioration and Title V Permitting

A. Overview

This final rule will regulate GHGs under CAA section 111. In this section, the EPA is addressing how regulation of GHGs under CAA section 111 could have implications for other EPA rules and for permits written under the CAA Prevention of Significant Deterioration (PSD) preconstruction permit program and the CAA Title V operating permit program. The EPA is adopting provisions in the regulations that explicitly address some of these potential implications based on our review of the proposed regulatory text and comments received on the proposal.

For purposes of the PSD program, the EPA is finalizing provisions in part 60 controls expected to be used for compliance with the final NSPS.

The final NSPS encourages the use of emission controls that recover hydrocarbon products, such as methane, that can be used onsite as fuel or reprocessed within the production process for sale. We estimate that the standards will result in a total cost of about $320 million in 2020 and $530 million in 2025 (in 2012 dollars).

C. What are the compliance costs?

The EPA estimates the total capital cost of the final NSPS will be $250 million in 2020 and $360 million in 2025. The estimate of total annualized engineering costs of the final NSPS is $390 million in 2020 and $640 million in 2025. This annual cost estimate includes capital, operating, maintenance, monitoring, reporting, and recordkeeping costs. This estimated annual cost does not take into account any producer revenues associated with the recovery of salable natural gas. The EPA estimates that about 16 billion cubic feet in 2020 and 27 billion cubic feet of natural gas in 2025 will be recovered by implementing the NSPS. In the engineering cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. After accounting for these revenues, the estimate of total annualized engineering costs of the final NSPS are estimated to be $320 million in 2020 and $530 million in 2025.[108] The price assumption is influential on estimated annualized engineering costs. A simple sensitivity analysis indicates $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $16 million in 2020 and $27 million in 2025.

D. What are the economic and employment impacts?

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the final rule on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the EIA and is used to produce the AEO, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA estimate that natural gas and crude oil drilling levels decline slightly over the 2020 to 2025 period relative to the baseline (by about 0.17 percent for natural gas wells and about 0.02 percent for crude oil wells). Natural gas production decreases slightly over the 2020 to 2025 period relative to the baseline (by about 0.03 percent), while crude oil production does not vary appreciably. Crude oil wellhead prices for onshore lower 48 production are not estimated to change appreciably over the 2020 to 2025 period relative to the baseline. However, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly over the 2020 to 2025 period relative to the baseline (about 0.20 percent). Net imports of natural gas are estimated to increase slightly over the 2020 to 2025 period relative to the baseline (by about 0.11 percent). Crude oil net imports are not estimated to change appreciably over the 2020 to 2025 period relative to the baseline.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, ''our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.'' (Executive Order 13563, 2011) While a standalone analysis of employment impacts is not included in a standard benefit-cost analysis, such an analysis is of particular concern in the current economic climate given continued interest in the employment impact of regulations such as this final rule.

The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, control activities, and labor associated with new reporting and recordkeeping requirements. We estimated up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at about 270 FTEs in both 2020 and 2025. The annual labor requirement to comply with final NSPS is estimated at about 1,100 FTEs in 2020 and 1,800 FTEs in 2025.

We note that this type of FTE estimate cannot be used to identify the specific number of employees involved or whether new jobs are created for new employees versus displacing jobs from other sectors of the economy.

E. What are the benefits of the final standards?

The final rule is expected to result in significant reductions in emissions. In 2020, the final rule is anticipated to reduce 300,000 short tons, or 280,000 metric tons, of methane (a GHG and a precursor to tropospheric ozone formation), 150,000 tons of VOC (a precursor to both PM (2.5 microns and less) ($PM_{2.5}$) and ozone formation), and 1,900 tons of HAP. In 2025, the final rule is anticipated to reduce 510,000 short tons (460,000 metric tons) of methane, 210,000 tons of VOC, and 3,900 tons of HAP. These pollutants are associated with substantial health effects, climate effects, and other welfare effects.

The final standards are expected to reduce methane emissions annually by about 6.9 million metric tons CO_2 Eq. in 2020 and by about 11 million metric tons CO_2 Eq. in 2025. It is important to note that the emission reductions are based upon predicted activities in 2020 and 2025; however, the EPA did not forecast sector-level emissions in 2020 and 2025 for this rulemaking. To give a sense of the magnitude of the reductions, the methane reductions expected in 2020 are equivalent to about 2.8 percent of the methane emissions for this sector reported in the United States GHG Inventory for 2014 (about 232 million metric tons CO Eq. from petroleum and natural gas production and gas processing, transmission, and storage). Expected reductions in 2025 are equivalent to around 4.7 percent of 2014 emissions. As it is expected that emissions from this sector would increase over time, the estimates compared against the 2014 emissions would likely overestimate the percent of reductions from total emissions in 2020 and 2025.

Methane is a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation that contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form tropospheric ozone and stratospheric water vapor, both of which also contribute to global warming. When accounting for the impacts of changing methane, tropospheric ozone, and stratospheric water vapor concentrations, the Intergovernmental Panel on Climate Change (IPCC) 5th Assessment Report (2013) found that historical emissions of methane accounted for about 30 percent of the total current warming influence (radiative forcing) due to historical emissions of GHGs. Methane is therefore a major contributor to the climate

[108] To the extent that NSPS affected facilities would have controlled emissions voluntarily through the Methane Challenge or other initiatives, the estimated costs and benefits of the NSPS would be lower than those included in the RIA analysis.

change impacts described previously. In 2013, total methane emissions from the oil and natural gas industry represented nearly 29 percent of the total methane emissions from all sources and account for about 3 percent of all CO_2-equivalent emissions in the United States, with the combined petroleum and natural gas systems being the largest contributor to United States anthropogenic methane emissions.

We calculated the global social benefits of methane emission reductions expected from the final NSPS standards for oil and natural gas sites using estimates of the social cost of methane (SC–CH_4), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. The SC–CH_4 estimates applied in this analysis were developed by Marten et al. (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO_2 (SC–CO_2), provides important context for understanding the Marten et al. SC–CH_4 estimates.[109] The SC–CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. Similar to the SC–CH_4, it includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. Estimates of the SC–CO_2 have been used by the EPA and other federal agencies to value the impacts of CO_2 emissions changes in benefit cost analysis for GHG-related rulemakings since 2008.

The SC–CO_2 estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC–CO_2 estimates and recommended four global values for use in regulatory analyses. The SC–CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2010 SC–CO_2 Technical Support Document (2010 TSD) provides a complete discussion of the methods used to develop these estimates and the current SC–CO_2 TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).[110]

The SC–CO_2 TSDs discuss a number of limitations to the SC–CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently, IAMs do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 reductions to inform benefit-cost analysis. The EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates and continue to consider feedback on the SC–CO_2 estimates from stakeholders through a range of channels, including public comments on Agency rulemakings, a separate Office of Management and Budget (OMB) public comment solicitation, and through regular interactions with stakeholders and research analysts implementing the SC–CO_2 methodology. See the RIA of this rule for additional details.

A challenge particularly relevant to this rule is that the IWG did not estimate the social costs of non-CO_2 GHG emissions at the time the SC–CO_2 estimates were developed. In addition, the directly modeled estimates of the social costs of non-CO_2 GHG emissions previously found in the published literature were few in number and varied considerably in terms of the models and input assumptions they employed [111] (EPA 2012). In the past, EPA has sought to understand the potential importance of monetizing non-CO_2 GHG emissions changes through sensitivity analysis using an estimate of the GWP of methane to convert emission impacts to CO_2 equivalents, which can then be valued using the SC–CO_2 estimates. This approach approximates the social cost of methane (SC–CH_4) using estimates of the SC–CO_2 and the GWP of methane.[112]

The published literature documents a variety of reasons that directly modeled estimates of SC–CH_4 are an analytical improvement over the estimates from the GWP approximation approach. Specifically, several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases.[113] The GWP reflects only the relative integrated radiative forcing of a gas over 100 years in comparison to CO_2. The directly modeled social cost estimates differ from the GWP-scaled SC–CO_2 because the relative differences in timing and magnitude of the warming between gases are explicitly modeled, the non-linear effects of temperature change on economic damages are included, and rather than treating all impacts over a hundred years equally, the modeled damages over the time horizon considered (300 years in this case) are discounted to present value terms. A detailed discussion of the limitations of the GWP approach can be found in the RIA.

In general, the commenters on previous rulemakings strongly encouraged the EPA to incorporate the monetized value of non-CO_2 GHG impacts into the benefit cost analysis. However, they noted the challenges associated with the GWP approach, as discussed above, and encouraged the use of directly modeled estimates of the SC–CH_4 to overcome those challenges.

Since then, a paper by Marten et al. (2014) has provided the first set of published SC–CH_4 estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the SC–CO_2 estimates.[114] [115]

[109] Previous analyses have commonly referred to the social cost of carbon dioxide emissions as the social cost of carbon or SCC. To more easily facilitate the inclusion of non-CO_2 GHGs in the discussion and analysis the more specific SC–CO_2 nomenclature is used to refer to the social cost of CO_2 emissions.

[110] Both the 2010 SC–CO_2 TSD and the current TSD are available at: *https://www.whitehouse.gov/omb/oira/social-cost-of-carbon*.

[111] U.S. EPA. 2012. Regulatory Impact Analysis Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. April. *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf*. Accessed March 30, 2015.

[112] For example, see (1) U.S. EPA. (2012). ''Regulatory impact analysis supporting the 2012 U.S. Environmental Protection Agency final new source performance standards and amendments to the national emission standards for hazardous air pollutants for the oil and natural gas industry.'' Retrieved from *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf* and (2) U.S. EPA. (2012). ''Regulatory impact analysis: Final rulemaking for 2017–2025 light-duty vehicle greenhouse gas emission standards and corporate average fuel economy standards.'' Retrieved from *http://www.epa.gov/otaq/climate/documents/420r12016.pdf*.

[113] See Waldhoff et al. (2011); Marten and Newbold (2012); and Marten et al. (2014).

[114] Marten et al. (2014) also provided the first set of SC–N_2O estimates that are consistent with the assumptions underlying the IWG SC–CO_2 estimates.

Continued

Specifically, the estimation approach of Marten et al. used the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach used by the IWG to develop the SC–CO_2 estimates.

The SC–CH_4 estimates from Marten et al. (2014) are presented below in Table 8. More detailed discussion of the SC–CH_4 estimation methodology, results and a comparison to other published estimates can be found in the RIA and in Marten et al.

TABLE 8—SOCIAL COST OF CH_4, 2012–2050 [a]

[In 2012$ per metric ton] (Source: Marten et al., 2014 [b])

Year	SC–CH_4			
	5% Average	3% Average	2.5% Average	3% 95th percentile
2012	$430	$1000	$1400	$2800
2015	490	1100	1500	3000
2020	580	1300	1700	3500
2025	700	1500	1900	4000
2030	820	1700	2200	4500
2035	970	1900	2500	5300
2040	1100	2200	2800	5900
2045	1300	2500	3000	6600
2050	1400	2700	3300	7200

Notes:

[a] There are four different estimates of the SC–CH_4, each one emissions-year specific. The first three shown in the table are based on the average SC–CH_4 from three integrated assessment models at discount rates of 5, 3, and 2.5 percent. The fourth estimate is the 95th percentile of the SC–CH_4 across all three models at a 3 percent discount rate. See RIA for details.

[b] The estimates in this table have been adjusted to reflect the minor technical corrections to the SC–CO_2 estimates described above. See the Corrigendum to Marten et al. (2014), *http://www.tandfonline.com/doi/abs/10.1080/14693062.2015.1070550.*

The application of these directly modeled SC–CH_4 estimates from Marten et al. (2014) in a benefit-cost analysis of a regulatory action is analogous to the use of the SC–CO_2 estimates. In addition, the limitations for the SC-CO_2 estimates discussed above likewise apply to the SC–CH_4 estimates, given the consistency in the methodology.

In early 2015, the EPA conducted a peer review of the application of the Marten et al. (2014) non-CO_2 social cost estimates in regulatory analysis and received responses that supported this application. See the RIA for a detailed discussion.

The EPA also carefully considered the full range of public comments and associated technical issues on the Marten et al. SC–CH_4 estimates received through this rulemaking. The comments addressed the technical details of the SC–CO_2 estimates and the Marten et al. SC–CH_4 estimates as well as their application to this rulemaking analysis. The commenters also provided constructive recommendations to improve the SC–CO_2 and SC–CH_4 estimates in the future. Based on the evaluation of the public comments on this rulemaking, the favorable peer review of the Marten et al. application, and past comments urging the EPA to value non-CO_2 GHG impacts in its rulemakings, the EPA concluded that the estimates represent the best scientific information on the impacts of climate change available in a form appropriate for incorporating the damages from incremental methane emissions changes into regulatory analysis. The EPA has included those benefits in the main benefits analysis. See the RTC document for the complete response to comments received on the SC-CH_4 as part of this rulemaking.

The methane benefits calculated using Marten et al. (2014) are presented in Table 9 for years 2020 and 2025. Applying this approach to the methane reductions estimated for the NSPS, the 2020 methane benefits vary by discount rate and range from about $160 million to approximately $960 million; the mean SC–CH_4 at the 3-percent discount rate results in an estimate of about $360 million in 2020. The methane benefits increase in the 2025, ranging from $320 million to $1.8 billion, depending on discount rate used; the mean SC–CH_4 at the 3-percent discount rate results in an estimate of about $690 million in 2025.

TABLE 9—ESTIMATED GLOBAL BENEFITS OF METHANE REDUCTIONS

[In millions, 2012$]

Discount rate and statistic	Year	
	2020	2025
Million metric tonnes of methane reduced	0.28	0.46
Million metric tonnes of CO_2 Eq.	6.9	11
5% (average)	$160	$320
3% (average)	$360	$690
2.5% (average)	$480	$890
3% (95th percentile)	$960	$1,800

[115] Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold & A. Wolverton (2014, online publication; 2015, print publication). Incremental CH_4 and N_2O mitigation benefits consistent with the United States Government's SC–CO_2 estimates, Climate Policy, DOI: 10.1080/14693062.2014.912981.

In addition to the limitation discussed above, and the referenced documents, there are additional impacts of individual GHGs that are not currently captured in the IAMs used in the directly modeled approach of Marten et al. (2014) and, therefore, not quantified for the rule. For example, in addition to being a GHG, methane is a precursor to ozone. The ozone generated by methane has important non-climate impacts on agriculture, ecosystems, and human health. The RIA describes the specific impacts of methane as an ozone precursor in more detail and discusses studies that have estimated monetized benefits of these methane generated ozone effects. The EPA continues to monitor developments in this area of research.

With the data available, we are not able to provide credible health benefit estimates for the reduction in exposure to HAP, ozone and $PM_{2.5}$ for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.[116] In addition to health improvements, there will be improvements in visibility effects, ecosystem effects and climate effects, as well as additional product recovery.

Although we do not have sufficient information or modeling available to provide quantitative estimates for this rulemaking, we include a qualitative assessment of the health effects associated with exposure to HAP, ozone and $PM_{2.5}$ in the RIA for this rule. These qualitative effects are briefly summarized below, but for more detailed information, please refer to the RIA, which is available in the docket. One of the HAP of concern from the oil and natural gas sector is benzene, which is a known human carcinogen. VOC emissions are precursors to both $PM_{2.5}$ and ozone formation. As documented in previous analyses (U.S. EPA, 2006[117], U.S. EPA, 2010[118], and U.S. EPA, 2014[119]), exposure to $PM_{2.5}$ and ozone is associated with significant public health effects. $PM_{2.5}$ is associated with health effects, including premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, and respiratory morbidity such as asthma attacks, acute bronchitis, hospital admissions and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment.[120] Ozone is associated with health effects, including hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.[121]

Finally, the control techniques to meet the standards are anticipated to have minor secondary emissions impacts, which may partially offset the direct benefits of this rule. The magnitude of these secondary air pollutant impacts is small relative to the direct emission reductions anticipated from this rule.

In particular, the EPA has estimated that an increase in flaring of natural gas in response to this rule will produce a variety of emissions, including about 1.0 million short tons of CO_2 in 2020 and about 1.2 million short tons of CO_2 in 2025. The EPA has not estimated the monetized value of the secondary emissions of CO_2 because much of the VOCs and methane that would have been released in the absence of the flare would have eventually oxidized into CO_2 in the atmosphere. Note that the CO_2 produced from the methane oxidizing in the atmosphere is not included in the calculation of the SC–CH_4.

For VOC emissions, the oxidization period is relatively short, on the order of a couple of weeks. However, for methane, the oxidization period is longer, on the order of a decade, and the EPA recognizes that because the growth rate of the SC-CO_2 estimates are lower than their associated discount rates, the estimated impact of CO_2 produced in the future via oxidized methane from fossil-based emissions may be less than the estimated impact of CO_2 released immediately from combustion. This would imply a small disbenefit associated with the earlier release of CO_2 during combustion of the methane emissions.

In the proposal, the EPA solicited comment on the appropriateness of monetizing the impact of the earlier release of CO_2 due to combusting methane emissions from oil and gas sites and an illustrative analysis that described a potential approach to approximate this value using the SC-CO_2. The EPA did not receive any comments regarding the appropriate methodology for conducting such an analysis, but did receive one comment letter that voiced general support for monetizing the secondary impacts. In consideration of this comment and recognizing the challenges and uncertainties related to estimation of these secondary emissions impacts for this rulemaking, EPA has continued to examine this issue in the context of this regulatory analysis (*i.e.,* the combusting of fossil-based methane at oil and gas sites) and explored ways to improve the illustrative analysis. See RIA for details.

X. Statutory and Executive Order Reviews

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

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

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential

[116] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates can provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with HAP and VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

[117] U.S. EPA. *RIA. National Ambient Air Quality Standards for Particulate Matter,* Chapter 5. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October 2006. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205—Benefits.pdf*.

[118] U.S. EPA. *RIA. National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2010. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf*.

[119] U.S. EPA. *RIA. National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. December 2014. Available on the Internet at *http://www.epa.gov/ttnecas1/regdata/RIAs/20141125ria.pdf*.

[120] U.S. EPA. *Integrated Science Assessment for Particulate Matter (Final Report)*. EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December 2009. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546*.

[121] U.S. EPA. *Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final)*. EPA/600/R–05/004aF–cF. Washington, DC: U.S. EPA. February 2006. Available on the Internet at *http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923*.

Attachment 3

U.S. EPA, **Regulatory Impact Analysis** of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources (May 2016) (excerpts)

Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

estimate of the turnover rates or rates of modification of relevant sources, as well as the number of wells on wellsites. While the EPA received comments on the projection methods used in the proposal RIA, we did not receive comments with sufficient information to further incorporate modification and turnover in the projection methodologies. The EPA has modified its methodology for using historical inventory information to estimate new sources reflecting comments received, resulting in lower estimates of the number of new compressor stations, pumps, compressors, and pneumatic controllers constructed each year. Newly constructed affected facilities are estimated based on averaging the year-to-year changes in the past 10 years of activity data in the Greenhouse Gas Inventory for compressor stations, pneumatic pumps, compressors, and pneumatic controllers. At proposal, this was done by averaging the increasing years only. The approach was modified to average the number of newly constructed units in all years. In years when the total count of equipment decreased, there were assumed to be no newly constructed units.

3.4.3 Emissions Reductions

Table 3-4 summarizes the national emissions reductions for the evaluated NSPS emissions sources and points for 2020 and 2025. These reductions are estimated by multiplying the unit-level emissions reductions associated with each applicable control and facility type by the number of incrementally affected sources. The detailed description of emissions controls is provided in the TSD. Please note that all results have been rounded to two significant digits.

Table 3-4 Emissions Reductions for Final NSPS Option 2, 2020 and 2025

Source/Emissions Point	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)
	Emissions Reductions, 2020			
Oil Well Completions and Recompletions	120,000	97,000	12	2,600,000
Fugitive Emissions	170,000	46,000	1,700	3,800,000
Pneumatic Pumps	13,000	3,600	140	290,000
Compressors	4,000	110	3	92,000
Pneumatic Controllers	1,300	37	1	30,000
Total	**300,000**	**150,000**	**1,900**	**6,900,000**
	Emissions Reductions, 2025			
Source/Emissions Point	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO_2 Eq.)**
Oil Well Completions and Recompletions	120,000	100,000	12	2,800,000
Fugitive Emissions	350,000	94,000	3,600	7,900,000
Pneumatic Pumps	26,000	7,200	270	590,000
Compressors	8,100	220	7	180,000
Pneumatic Controllers	2,700	74	2	61,000
Total	**510,000**	**210,000**	**3,900**	**11,000,000**

3.4.4 Product Recovery

The annualized cost estimates presented below include revenue from additional natural gas recovery. Several emission controls for the NSPS capture methane and VOC emissions that would otherwise be vented to the atmosphere. A large proportion of the averted methane emissions can be directed into natural gas production streams and sold. For the environmental controls that avert the emission of saleable natural gas, we base the estimated revenues from implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right in an increment consistent with the technically achievable emissions transferred into the production stream as a result of the final NSPS. We enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per-well basis for new wells (Table 6-1).

6.2.3 Energy Markets Impacts

We estimate impacts to drilling activity, price and quantity changes in the production of crude oil and natural gas, and changes in international trade of crude oil and natural gas. In each of these estimates, we present estimates for the baseline years of 2020 and 2025 and predicted results for 2020 and 2025 under the final rule. We also present impacts over the 2020 to 2025 period. For context, we provide estimates of production activities in 2012. With the exception of examining crude oil and natural gas trade, we focus the analysis on onshore oil and natural gas production activities in the continental (lower 48) U.S. We do this because offshore production is not affected by the NSPS and the bulk of the rule's impacts are expected to be in the continental U.S.

We first report estimates of impacts on crude oil and natural gas drilling activities and production. Table 6-2 presents estimates of successful onshore natural gas and crude oil wells drilled in the continental U.S.

Table 6-2 Successful Oil and Gas Wells Drilled (Onshore, Lower 48 States)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	Baseline	NSPS	Baseline	NSPS	Baseline	NSPS
Successful Wells Drilled							
Natural Gas	10,490	10,501	10,481	12,200	12,145	65,896	65,785
Crude Oil	28,496	27,455	27,463	29,244	29,231	168,768	168,736
Total	**38,986**	**37,956**	**37,944**	**41,444**	**41,376**	**234,664**	**234,521**
% Change in Successful Wells Drilled from Baseline							
Natural Gas			0.19%		-0.45%		-0.17%
Crude Oil			0.03%		-0.04%		-0.02%
Total			**0.03%**		**-0.16%**		**-0.06%**

Results show that the final NSPS will have a relatively small impact on onshore well drilling in the lower 48 states. Drilling remains essentially unchanged in 2020, with very slight increases both oil and natural gas wells, relative to the baseline. Meanwhile, drilling of both natural gas and crude oil wells decreases slightly in 2025, relative to the baseline. The small increase in drilling in 2020 is somewhat counter-intuitive as production costs have been increased under the proposed NSPS. However, given NEMS is a dynamic, multi-period model, it is important to examine changes over multiple periods. Crude oil drilling over the 2020 to 2025 period decreases overall but by about 30 wells total, or about 0.02 percent, relative to the baseline. Natural gas drilling, over the same period remains declines by about 110 wells total, or about 0.17 percent, relative to the baseline.

Table 6-3 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS.

Table 6-3 Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	Baseline	NSPS	Baseline	NSPS	Baseline	NSPS
Domestic Production							
Natural Gas (trillion cubic feet)	22.158	26.544	26.537	28.172	28.163	164.130	164.086
Crude Oil (million bbls/day)	4.597	8.031	8.031	8.027	8.028	48.084	48.086
% Change in Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)							
Natural Gas			-0.03%		-0.03%		-0.03%
Crude Oil			0.00%		0.01%		0.00%

As indicated by the estimated change in the new well drilling activities, the analysis shows that the proposed NSPS will have a relatively small impact on onshore natural gas and crude oil production in the lower 48 states. Crude oil production remains essentially unchanged in 2020 and 2025 (with changes around or less than 0.01 percent in both years), relative to the baseline. While slightly increasing over the time horizon, the overall change in crude oil production is less than 0.01 percent, relative to the baseline. Natural gas production is estimated to decrease slightly during the 2020-25 period, by around 0.03 percent, relative to the baseline.

Note this analysis estimates very little change in domestic natural gas production, despite some environmental controls anticipated in response to the rule capture natural gas that would otherwise be emitted (about 16 bcf in 2020 and 27 bcf in 2025). NEMS models the adjustment of energy markets to the new slightly more costly natural gas and crude oil productive activities. At the new post-rule equilibrium, producers implementing emissions controls are still anticipated to capture and sell the captured natural gas, and this natural gas might offset other production, but not so much as to make overall production increase from the baseline projections.

Table 6-4 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states.

Table 6-4 Average Natural Gas and Crude Oil Wellhead Price (Onshore, Lower 48 States, 2012$)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	**Baseline**	**NSPS**	**Baseline**	**NSPS**	**Baseline**	**NSPS**
Lower 48 Average Wellhead Price							
Natural Gas (2012$ per Mcf)	2.566	4.428	4.441	5.184	5.190	4.880	4.890
Crude Oil (2012$ per barrel)	94.835	73.920	73.918	85.219	85.218	79.530	79.527
% Change in Lower 48 Average Wellhead Price from Baseline							
Natural Gas			0.29%		0.12%		0.20%
Crude Oil			0.00%		0.00%		-0.01%

Wellhead crude oil prices for onshore lower 48 production are not estimated to change meaningfully in 2020 or 2025, or over the 2020-25 period, relative to the baseline. The production-weighted average price for wellhead crude oil over the 2020 to 2025 period is not estimated to change more than 0.01 percent, relative to the baseline. Meanwhile, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly in response

Attachment 4

Office of Management and Budget, Notice Pending EO 12866 Regulatory Review: Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: **Extension of Stay for Certain Requirements** (last visited June 3, 2017)

Pending EO 12866 Regulatory Review

RIN: 2060-AT59 **View EO 12866 Meetings**

Received Date: 05/24/2017

Title: Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Extension of Stay for Certain Requirements

Agency/Subagency: EPA / OAR

Stage: Proposed Rule

Legal Deadline: None

Economically Significant: No

International Impacts: No

Affordable Care Act [PPACA, P.L. 111-148 & 111-152]: No

Dodd-Frank Act [Dodd-Frank Wall Street Reform and Consumer Protection Act, P.L. 111-203]: No

Attachments 32

Attachment 5

Declaration of Dr. David R. Lyon, Environmental Defense Fund

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

DECLARATION OF DR. DAVID R. LYON

I, David R. Lyon, declare as follows:

1. I am a Scientist at the Environmental Defense Fund ("EDF").
2. I earned a PhD in Environmental Dynamics from the University of Arkansas, where I wrote my dissertation on *Quantifying, Assessing, and Mitigating Methane Emissions from Super-emitters in the Oil and Gas Supply Chain*. Prior to earning my PhD, I worked in the Arkansas Department of Environmental Quality, where I analyzed emissions data and managed an air pollution emissions inventory program. My curriculum vitae is attached as Exhibit A.
3. I joined EDF in 2012. At EDF, my work focuses on identifying and analyzing emissions from the oil and natural gas industry. I design, plan, execute, and analyze scientific studies to measure methane emissions from the natural gas supply chain. This has included helping to lead a multi-institutional effort to measure facility-specific and regional methane emissions in the Barnett Shale along with several studies characterizing super-emitters—disproportionally large emitters that are often not fully captured in emissions inventories. I have authored or coauthored numerous

peer-reviewed journal articles describing the results of these studies and have served as an expert reviewer of the Petroleum Systems and Natural Gas Systems portions of EPA's U.S. Inventory of Greenhouse Gas Emissions and Sinks.

EPA's Leak Detection and Repair Requirements in the 2016 Rule.

4. The Administrator has signed a notice to stay for 90 days the leak detection and repair requirements ("LDAR") in EPA's final rule: Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed and Modified Sources, 81 Fed. Reg. 35,824 ("2016 Rule"). EPA has also sent a proposal to the Office of Management and Budget to extend the stay of these provisions.

5. These leak detection and repair standards require affected sources, which include new and modified well sites and compressor stations, to monitor for leaks using instrument-based technologies like infrared cameras and to fix any leaks within 30 days of the monitoring survey. The 2016 Rule requires that well sites undertake these LDAR surveys twice a year and that compressor stations complete such surveys quarterly. The deadline for affected facilities to complete their initial surveys was June 3, 2017,[1] one

[1] The regulations require sources to comply by June 3, 2017 or within 60 days of the commencement of production, whichever is later. Accordingly, some more recently drilled wells that have not yet commenced production may have later compliance deadlines. These sources are discussed more fully in later portions of this declaration.

year after the final rule was signed several days after the Administrator signed EPA's 90-day stay notice.

EPA's Stay Will Allow Thousands of Oil and Natural Gas Facilities To Forego Inspection and Repair of Leaks.

6. The 2016 Rule applies to facilities "constructed, modified or reconstructed" after September 18, 2015—the date of EPA's proposed rule. 81 Fed. Reg. 35824, 35844 (June 3, 2016). As described above, EPA's LDAR standards apply to new well sites and compressor stations, *id.* at 35826, sources that have commenced construction after September 18, 2015. The standards also apply to modified well sites and compressor stations. The 2016 Rule defines particular circumstances that constitute a modification at each of these facilities. For well sites, these include when a well at an existing site is fractured or re-fractured, an operation that is designed to increase production of natural gas. 40 CFR 60.5365a(i)(3). For compressor stations, the 2016 Rule defines modifications to include the addition of a compressor at an existing station. 40 CFR 60.5365a(j).

7. To analyze the number of affected well sites that, but for EPA's stay, would have been required to perform LDAR surveys and reduce their emissions, I used Drillinginfo, a proprietary database that compiles information from state oil and gas commissions concerning a wide range of drilling and production-related information.

8. Drillinginfo includes information on the "spud date" for wells, or the date on which drilling commenced. The database also includes information on well "completion dates," or the most recent date on which a well was cleared of flowback gas associated with hydraulic fracturing or re-fracturing. Using the database, I isolated wells with a spud date after September 18, 2015, which would be "new" for purposes of the 2016 Rule's LDAR requirements. Separately, I identified wells with a spud date on or before September 18, 2015 but a completion date after September 18, 2015. This distinct category of sources category includes both older, re-fractured wells and new wells with their initial fracture delayed to after September 18, 2015, which would be "modified" for purposes of the 2016 Rule's LDAR requirements.

9. I further narrowed this dataset in several ways to conservatively approximate the number of wells that would have had to perform LDAR absent EPA's stay. First, I removed offshore wells and wells with a producing status that is either abandoned, shut in, cancelled or plugged and abandoned. This yielded a total of 18,231 affected wells (9,262 new wells and 8,969 modified wells that were spudded before September 18, 2015 but completed after that date to avoid any double counting).

10. Second, I isolated, excluded, and separately characterized wells that had not yet reported any oil or gas production. Of the 18,231 total wells, 3,778

wells, or about 20 percent, are not yet producing (2,998 new wells and 790 modified wells). These wells are affected facilities under the NSPS that will have to perform LDAR surveys by June 3, 2017 or within 60 days of first production, whichever is later. While lack of production data is often simply due to a lag in reporting, some of these wells may not yet have commenced production. In that case, non-producing wells may not have had to perform surveys by June 3, but would nonetheless need to complete an initial survey within 60 days of first production. Because that date may fall within the 90-day stay and, at minimum, would likely fall within EPA's anticipated extended stay, I have retained these sources as a separate category, but have not attributed any emission reductions to these wells.

11. Third, a number of states have adopted LDAR standards under their own state authorities. EPA recognized this in its final Regulatory Impact Analysis and, because of these preexisting state-level requirements, determined that the 2016 Rule would not have costs for new and modified sources in Colorado, Wyoming, Utah, and Ohio.[2] Along with these states, California has subsequently adopted LDAR requirements and Pennsylvania provides an exemption from air permitting requirements for well sites if the

[2] EPA, *Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources* at 3-10 (EPA-452/R-16-002, May 2016) ("RIA").

operator voluntarily performs annual LDAR. Accordingly, I have isolated, excluded, and separately characterized producing wells in these states. The dataset includes 3,667 affected wells in such states (2,767 new wells and 900 modified wells). Separating these sources results in a conservative estimate of foregone emission reductions, because EPA's LDAR requirements are more protective than some state standards and so would likely deliver incremental benefits for some of these sources if not for the stay. This analysis is also particularly conservative given that the Pennsylvania provisions addressing LDAR at well sites are not mandatory.

12. After making these conservative adjustments, there are 11,883 producing wells in states without preexisting LDAR requirements that will not now be required to inspect and repair their leaks because of EPA's stay. As discussed above, however, many of the additional wells that have been excluded from this count in the full dataset would nonetheless likely experience emission benefits due to EPA's LDAR standards.

13. My estimate of wells that will not have to comply with the 2016 Rule's LDAR requirements because of EPA's stay is also conservative because it does not include all recently-completed wells or wells that will be completed during the stay period. In particular, the Drillinginfo data, though the most recently available, often does not include activity from the last several

months. For instance, the most recently available data for Texas, the state with the largest number of newly-drilled and modified wells, is April of 2017. And for other states, like Pennsylvania, the data is current only to December of 2016. As of June 2, 2017, Baker Hughes reports that there are 916 active drilling rigs drilling new wells in the United States—wells that likely are not captured by the Drillinginfo database and now will be affected by the stay.[3] Similarly, Drillinginfo reports more than 16,000 new oil and gas wells have been permitted in 2017, less than 30% of which have already been drilled. More broadly, every day a stay is in place, additional, new wells are being drilled and completed, compounding the number of sources that may not be required to perform leak detection and repair because of EPA's stay. For instance, in the Regulatory Impact Analysis for the 2016 Rule, EPA estimated that 22,355 additional new oil wells and 15,773 additional natural gas wells would be drilled in the lower 48 states in 2017 alone.[4]

14. Finally, I assumed that few sources would choose to comply with LDAR standards in advance of the compliance deadline and as a result, that any such pre-compliance would not meaningfully affect my emissions estimates.

[3] Baker Hughes, Inc., *Rig Count Overview & Summary Count* (June 2, 2017), http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-rigcountsoverview.
[4] RIA at 2-28.

This is a reasonable assumption because operators have identified a full one-year phase-in as necessary, in their view, to enable compliance.[5] It is likewise reasonable because EPA provided assurance in an April 18th letter from the Administrator that the agency would be suspending the LDAR requirements.

15. Table 1 summarizes my analysis of wells affected by EPA's stay of the 2016 Rule LDAR requirements. Table 2 contains production information for affected wells. Figures 1 and 2 include maps of affected wells both nationally and in states without state regulations requiring some form of LDAR.

Table 1: Summary of Affected Well Sites

	New Wells	Modified Wells	All Wells	Producing Wells
Nationwide	9,262	8,969	18,231	14,451
States with no LDAR Requirements	6,495	8,069	14,564	11,883

[5] *See, e.g.*, EPA, Responses to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 4-482 (May 2016), *available at* https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7632 (Comment of American Petroleum Institute requesting one-year plus 60 day phase in "to allow operators time to purchase monitoring devices, conduct training, and establish protocols.").

Table 2: Summary of Oil and Gas Production*

	New Well Production	Modified Well Production	All Wells Production	Low-Producing Wells
Oil [bbl]	304,204,004	389,426,822	693,630,826	13,272,131
Gas [Mcf]	1,755,731,292	2,559,954,063	4,315,685,355	54,929,176

*Estimated oil and gas production data only include months since the completion or recompletion that occurred after September 18, 2015.

Figure 1: Map of Total Affected Well Sources

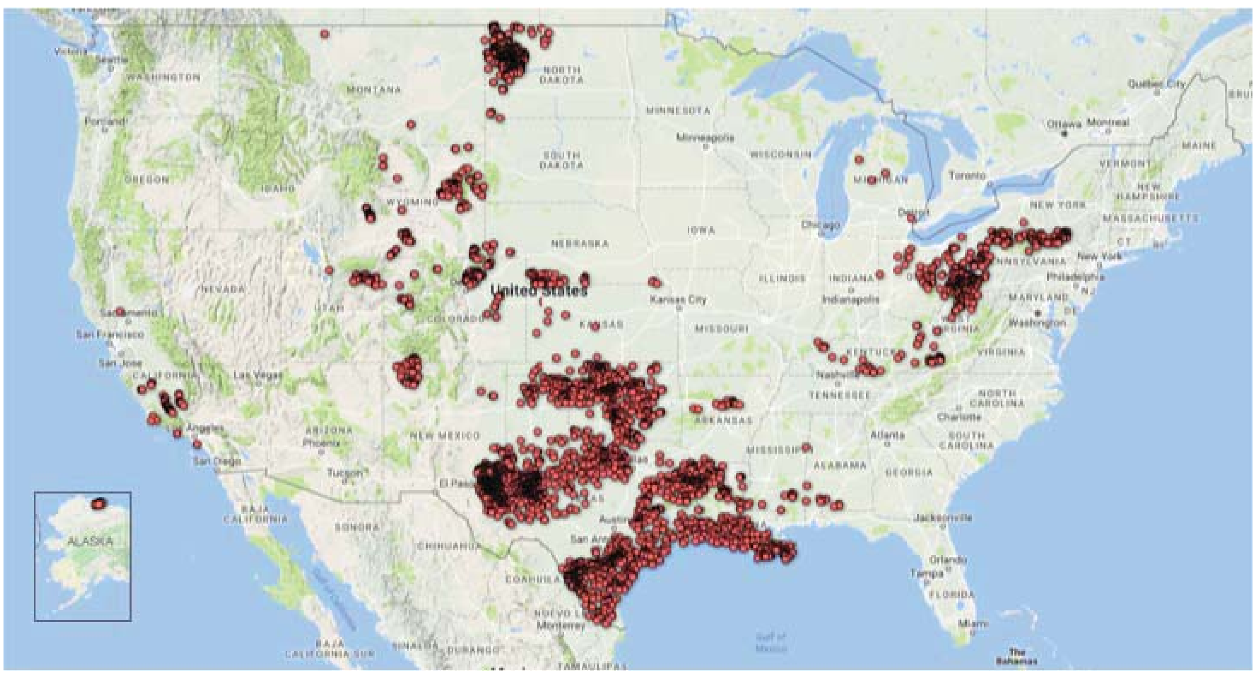
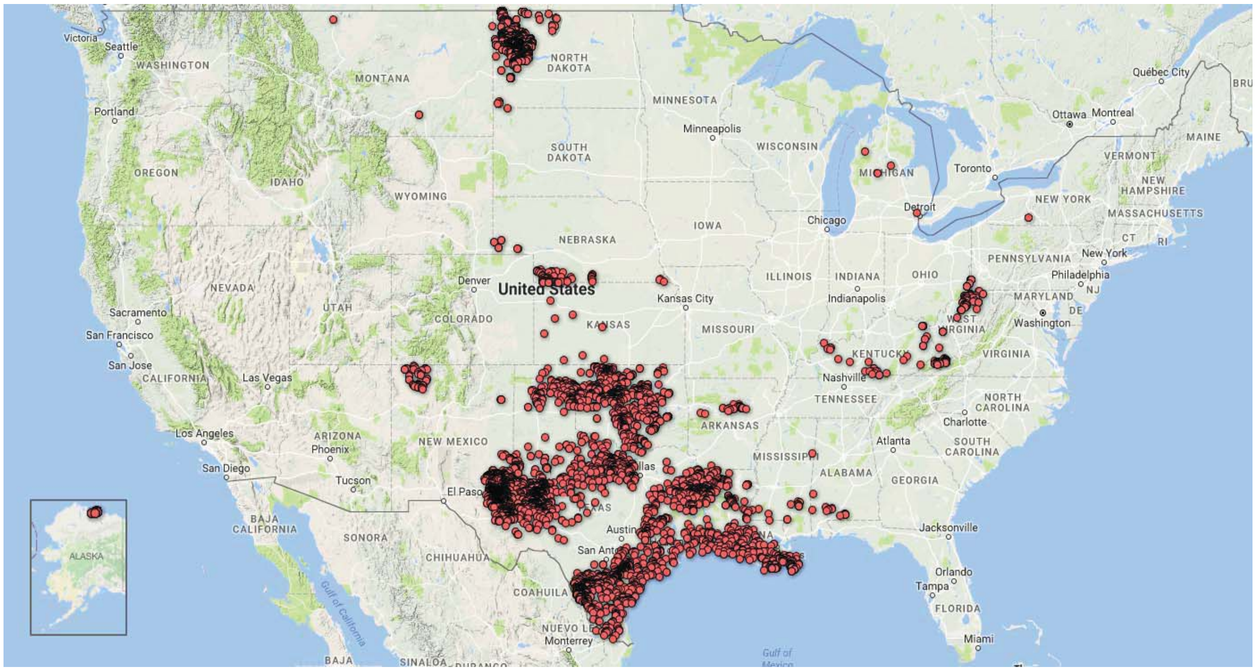


Figure 2: Map of Affected Well Sources in States Without LDAR Requirements



16. Drillinginfo does not compile information on compressor stations. To estimate the impacts of the stay on these sources, I used EPA's projections in the Technical Support Document for the final rule, Table 9-1, which estimate 480 additional affected compressor stations by 2020. Assuming this estimate reflects a constant rate of new development, I estimated that 96 new gathering and boosting compressor stations would be subject to EPA's now suspended LDAR requirements. I undertook a similar approach to analyzing likely new transmission and storage compressor stations,

estimating that 4 transmission and 5 storage facilities were constructed since September 18, 2015.[6]

EPA's Stay of the Leak Detection and Repair Standards Will Result in Additional Emissions of Harmful Methane, Volatile Organic Compounds, and Hazardous Air Pollutants from Well Sites.

17. A stay of the 2016 Rule's LDAR provisions will result in additional emissions of methane, volatile organic compounds ("VOCs"), and hazardous air pollutant emissions that would otherwise be remediated by these requirements. Methane is a powerful short-term climate forcer with over 80 times the global warming potential of carbon dioxide on a mass basis over the first 20-years after it is emitted. VOCs react with nitrogen oxides to form ground-level ozone, or smog, which can cause respiratory disease and premature death. Other hazardous air pollutants emitted by oil and gas sources include benzene, a known human carcinogen.

18. To estimate emissions that will now continue unabated because of EPA's stay, I have used information in EPA's Technical Support Document on average methane and VOC leak emissions[7] from oil and natural gas well sites; the reductions EPA estimates from performing semiannual LDAR at

[6] EPA, Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, subpart OOOOa, Table 9-1 (May 2016), *available at* https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7631.
[7] *Id.* at Tables 4-3, 4-5. EPA's well site model plants assume a two wellhead pad. Oil well emissions are based on EPA's estimates for well sites with a gas-to-oil ratio of less than 300 standard cubic feet of gas per stock barrel of oil.

well sites; and the number of affected well sites from my analysis of the Drillinginfo database, analyzed above. Emissions estimates of hazardous air pollutants ("HAPs") from producing wells are estimated using EPA's HAP-to-methane ratio for equipment leaks from oil and gas well sites.[8]

19. My analysis assumes, consistent with EPA's technical analysis, that semiannual monitoring will reduce annual emissions by 60% and quarterly monitoring will result in an 80% annual emission reduction.[9] While these inspections would not all occur within the initial, 90-day stay period, EPA has indicated that it will extend the stay beyond 90 days, and so these estimates provide a reasonable approximation of the near-term impacts of EPA's stays.

20. To provide a conservative, lower-bound estimate of the emissions impacts of the 90-day stay, I have assumed a constant rate of reduction over the year and reduced the annual emission reduction benefits accordingly. This assumption understates, perhaps significantly, the true foregone benefits of the initial survey, which was required to take place by June 3, 2017. This is because field surveys have often found that equipment leak emissions are highest shortly after the completion of a new facility. For example, third-

[8] *Id.* at Table 14-1.
[9] *See id.* at Tables 4-10, 4-11.

party data from Jonah Energy shows reductions of nearly 60% for the initial survey[10]—substantially greater than the estimated 90-day reductions in Table 3. For this reason, my conservative assumption provides a likely lower bound estimate of the foregone emission reductions during the 90-day stay period, and in practice, the initial survey would likely help to secure much of the 60% annual reduction that EPA projects for well sites that comply with the LDAR requirements.

21. As described above, 18,231 wells that would otherwise have had to comply with LDAR requirements do not have to comply with those requirements during the stay. If none of these wells conduct LDAR, I estimate that additional emissions of 21,395 tons of methane, 5,899 tons of VOC, 225 tons of hazardous air pollutants will occur on an annual basis. As I explain above, this is a reasonable proxy for excess emissions that would result from a stay of the initial survey, as well as for annual emission reductions that would be lost if the 90-day stay is extended. If we instead adopt the conservative assumption that well sites leak at a constant rate, a lower bound estimate of excess emissions just during the 90-day stay period is 5,349 tons of methane, 1,475 tons of VOC, and 56 tons of hazardous air pollutants. As

[10] Comment of Clean Air Task Force *et al* on EPA's Proposed NSPS for the Oil and Natural Gas Sector, at Exhibits TA1-TA6, EPA Doc. Id No. EPA-HQ-OAR-2010-0505-7062. Relevant portions of the presentation are attached to this declaration as Exhibit B.

noted in paragraph 20, this lower bound estimate of excess emissions during the 90-day stay period likely understates the actual foregone emission reduction. Table 3 below summarizes the total number of affected sites, affected producing sites in states without separate state LDAR requirements, affected producing sites in ozone nonattainment areas, and affected low-producing sites along with additional emissions attributable to each of these categories.

Table 3: Summary of Affected Well Sources and Associated Emissions.

	# of Affected Wells	% of Affected Wells	Annual Emissions [tons]			90-day Emissions* [tons]		
			Methane	VOC	HAPs	Methane	VOC	HAPs
Total Sources	18,231	100%	21,395	5,899	225	5,349	1,475	56
Producing Wells in States with No LDAR Requirements	11,883	65%	17,204	4,742	181	4,301	1,185	45
Producing Wells in Ozone Non-attainment Area Counties	1,831	10%	3,013	832	32	753	208	8
Low-Producing Well Sources [based on NSPS definition]	2,179	12%	3,300	910	35	825	228	9

*Assumes a constant rate of reduction over the year which understates, perhaps significantly, the true foregone benefits of the initial survey, which reduces emissions substantially at the time of its completion.

22. Of the total wells that are subject to the NSPS and do not have to comply with the LDAR requirements during the stay, nearly 65%, or 11,883

producing wells, are located in states that do not have their own state regulations requiring LDAR.[11] These incremental sources will remain unregulated during the stay of the NSPS LDAR provisions, and I estimate that these sources will add 17,204 tons of methane emissions, 4,742 tons of VOC emissions, and 181 tons of hazardous air pollutant emissions into the air on an annual basis. A lower-bound estimate of excess emissions that will occur just during the 90-day stay period is 4,301 tons of methane, 1,185 tons of VOC, and 45 tons of hazardous air pollutants. As noted above, however, the LDAR requirements in the NSPS would also likely yield additional emission reductions even from affected wells that are already subject to state-level LDAR requirements.

Additional Ozone Forming Emissions Will Occur in Areas with Unhealthy Ozone Air Quality.

23. In ozone non-attainment areas, the incremental emissions during the stay from sources that would be covered by the NSPS LDAR requirements may have a particularly deleterious effect on local and regional ozone levels. There are 2,217 wells subject to the NSPS in counties that are currently not in attainment with the 2008 national ambient air quality standards for ozone. These sources will add an estimated 832 tons of VOCs to the atmosphere

---

[11] *See supra* ¶ 11.

during the stay of the LDAR requirements, which can contribute to the formation of additional ozone and exacerbating smog-related health issues. The timing of the stay results in these additional VOCs being released during peak ozone season summer months of June, July, and August during which VOCs and nitrogen oxides react with strong sunlight and heat.

Low Producing Wells Account for a Small Fraction of the Affected Facilities That Would Have Had to Comply with LDAR Requirements on June 3, 2017.

24. Although EPA has granted reconsideration specifically on the inclusion of low-production wells in the final NSPS, EPA's administrative stay goes far beyond these low-production wells to suspend fugitive emissions monitoring for all sources, including sources for which the agency is not reconsidering the standards. Low-production wells—which EPA defined in the proposed NSPS as wells that produce less than 15 barrels of oil equivalent per day—account for just 12% of total wells in the above dataset covered by the NSPS. The stay, however, sweeps broadly and includes both low and high-producing wells. The latter category, which is not subject to EPA's grant of reconsideration, accounts for the vast majority of wells and emissions. The 16,052 non-low production wells covered by the NSPS will emit an estimated 18,095 tons of methane, 4,989 tons of VOCs, and 190 tons of

hazardous air pollutants during the course of the 90-day stay, representing roughly 85% of the foregone methane reductions from all sources.

EPA Has Also Stayed LDAR Requirements for Compressor Stations, Which Are a Significant Source of Emissions but Not Subject to Any Grant of Reconsideration.

25. EPA has also stayed LDAR requirements for compressor stations, although it is not reconsidering the requirements applicable to those sources. Compressors are an important additional source of emissions, which I have estimated based on the number of affected sources and emissions reductions included in EPA's Technical Support Document. Table 4, below sets forth the results of this analysis.

Table 4: Summary of Compressor Station Emissions

	# of Affected Compressor Stations	Annual Emissions* [tons]			90-day Emissions** [tons]		
		Methane	VOC	HAPs	Methane	VOC	HAPs
Gathering and Boosting Compressor Stations	96	3,360	938	35	840	234	9
Transmission Compressor Stations	4	160	4	2	40	1	0.4
Storage Compressor Stations	5	710	20	7	178	5	2

* Emissions estimates are based on EPA Model Plant estimates in Tables 4-7 and 4-8 of the final TSD.
** Assumes a constant rate of reduction over the year which understates, perhaps significantly, the true foregone benefits of the initial survey, which reduces emissions substantially at the time of its completion.

Conclusion

26. EPA's stay will allow numerous sources to forego leak detection and repair requirements, allowing significant emissions to persist from these sources during both the 90-day stay period and beyond. The above analysis conservatively estimates the impacts of this stay, though the true impacts could be much greater and will swiftly grow over time as additional wells are drilled and completed without the need to meet standards to detect and remediate their leaking emissions.

I declare that the foregoing is true and correct.

David R. Lyon

David R. Lyon

Dated June 4, 2017

EXHIBIT A

David Richard Lyon

301 Congress Ave, Suite 1300, Austin, TX 78701
1-512-691-3414 • dlyon@edf.org

EDUCATION

University of Arkansas, Fayetteville, AR
- Ph.D. in Environmental Dynamics (May 2016)
- Dissertation: Quantifying, Assessing, and Mitigating Methane Emissions from Super-emitters in the Oil and Gas Supply Chain
- Honors: 4.0 GPA; Doctoral Academy Fellowship

University of Kentucky, Lexington, KY
- M.S. in Forestry (May 2004)
- Thesis: Persistent effects of eastern redcedar on calcareous glade soils and plant community
- Honors: 4.0 GPA; Garden Club of America 2003 Fellowship in Ecological Restoration

Hendrix College, Conway, AR
- B.A. in Biology with Chemistry Minor (June 2002)
- Honors: 3.95 GPA; Summa Cum Laude with Distinction; Phi Beta Kappa

WORK EXPERIENCE

Environmental Defense Fund, Austin, TX
Scientist (March 2014 – present)
- Contribute to the design, planning, execution, and analysis of new EDF-sponsored field studies on methane emissions from the natural gas supply chain, including a leading role in the Barnett Shale Coordinated Campaign and super-emitter studies
- Prepare and review research manuscripts for submission to peer-reviewed journals
- Provide scientific expertise to other EDF programs and external groups
- Continue performing research analyst job tasks listed below

Environmental Defense Fund, Austin, TX
Research Analyst (June 2012 – March 2014)
- Perform literature reviews and research, analyze, synthesize, and interpret information on a variety of topics to inform the design and conduct of EDF-sponsored field studies to quantify leakage across the natural gas supply chain
- Analyze, interpret, and communicate scientific data to state and federal policymakers in support of EDF advocacy on environmental policy
- Actively develop reports/fact sheets/blog posts for general audiences
- Independently support other "rapid response" and/or project development efforts
- Support fundraising and external communication efforts
- Apply organizational, communication, and planning skills in preparing correspondence and reports, responding to requests for information, and helping coordinate activities among staff

University of Arkansas at Little Rock, Little Rock, AR
Part-time Lecturer (January 2012 – May 2012)

- Taught undergraduate environmental science course “Fundamentals of Air Pollution”

Arkansas Department of Environmental Quality, North Little Rock, AR
Environmental Program Coordinator (January 2009 – May 2012)

- Obtained EPA funding, managed project, and primary report author for a study to develop an emissions inventory and monitor air quality impacts of natural gas development in the Fayetteville Shale
- Project manager of $500,000 project to develop and implement a web-based emissions inventory reporting system for a multi-state consortium of environmental agencies
- Managed air pollution emissions inventory program including collecting data from approximately 175 regulated facilities and estimating emissions for several nonpoint emission source categories
- Analyzed emissions data and produced reports for the agency and public
- Analyzed current and proposed federal air regulations to assist agency planning
- Supervised up to four staff on emission inventory team

University of Arkansas, Fayetteville, AR
Graduate Assistant (August 2004 – December 2008)

- Performed research on the effects of nutrient enrichment on stream carbon cycling
- Assisted students in general ecology laboratory

University of Kentucky, Lexington, KY
Graduate Assistant (June 2002 – June 2004)

- Performed research in restoration ecology and soil biogeochemistry of calcareous glades
- Taught undergraduate students tree identification

PUBLICATIONS

Zavala-Araiza, D., Alvarez, R. A., Lyon, D. R., Allen, D. T., Marchese, A. J., Zimmerle, D. J., & Hamburg, S. P. (2017). Super-emitters in natural gas infrastructure are caused by abnormal process conditions. Nature communications, 8, 14012.

Alvarez, R. A., Lyon, D. R., Marchese, A. J., Robinson, A. L., & Hamburg, S. P. (2016). Possible malfunction in widely used methane sampler deserves attention but poses limited implications for supply chain emission estimates. Elementa, 4.

Marrero, J. E., Townsend-Small, A., Lyon, D. R., Tsai, T. R., Meinardi, S., & Blake, D. R. (2016). Estimating Emissions of Toxic Hydrocarbons from Natural Gas Production Sites in the Barnett Shale Region of Northern Texas. Environmental Science & Technology, 50(19), 10756-10764.

Lamb, B. K., Cambaliza, M. O., Davis, K. J., Edburg, S. L., Ferrara, T. W., Floerchinger, C., ... & Lyon, D. R. (2016). Direct and indirect measurements and modeling of methane emissions in Indianapolis, Indiana. Environmental Science & Technology, 50(16), 8910-8917.

Lyon, D. R. (2016). Methane emissions from the natural gas supply chain. In: Kaden, D.A. and Rose, T.L. eds. *Environmental and Health Issues in Unconventional Oil and Gas Development*. Elsevier. pp. 33-48.

Lyon, D. R., Alvarez, R. A., Zavala-Araiza, D., Brandt, A. R., Jackson, R. B., & Hamburg, S. P. (2016). Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites. *Environmental Science & Technology*, 50 (9), pp 4877–4886, DOI: 10.1021/acs.est.6b00705.

Townsend-Small, A., Ferrara, T. W., Lyon, D. R., Fries, A. E., & Lamb, B. K. (2016). Emissions of coalbed and natural gas methane from abandoned oil and gas wells in the United States. *Geophysical Research Letters*, 43(5), 2283-2290, DOI: 10.1002/2015GL067623.

Zavala-Araiza, D., Lyon, D. R., Alvarez, R. A., Davis, K. J., Harriss, R., Herndon, S. C., ... & Marchese, A. J. (2015). Reconciling divergent estimates of oil and gas methane emissions. *Proceedings of the National Academy of Sciences*, 112(51), 15597-15602, DOI: 10.1073/pnas.1522126112

Lyon, D. R. ; Zavala-Araiza, D.; Alvarez, R.; Harriss, R.; Palacios, V.; Lan, X.; Lavoie, T.; Mitchell, A.; Yacovitch, T.; Herndon, S.; Marchese, A.; Zimmerle, D.; Robinson, A. .; Hamburg, S. (2015). Constructing a spatially-resolved methane emission inventory for the Barnett Shale region. *Environmental Science & Technology*, 49, 8147-8157, DOI: 10.1021/es506359c.

Zavala-Araiza, D.; Lyon, D. R.; Alvarez, R. A.; Palacios, V.; Harriss, R.; Lan, X.; Talbot, R.; Hamburg, S. P. (2015). Towards a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. *Environmental Science & Technology*, 49, DOI: 10.1021/ acs.est.5b00133.

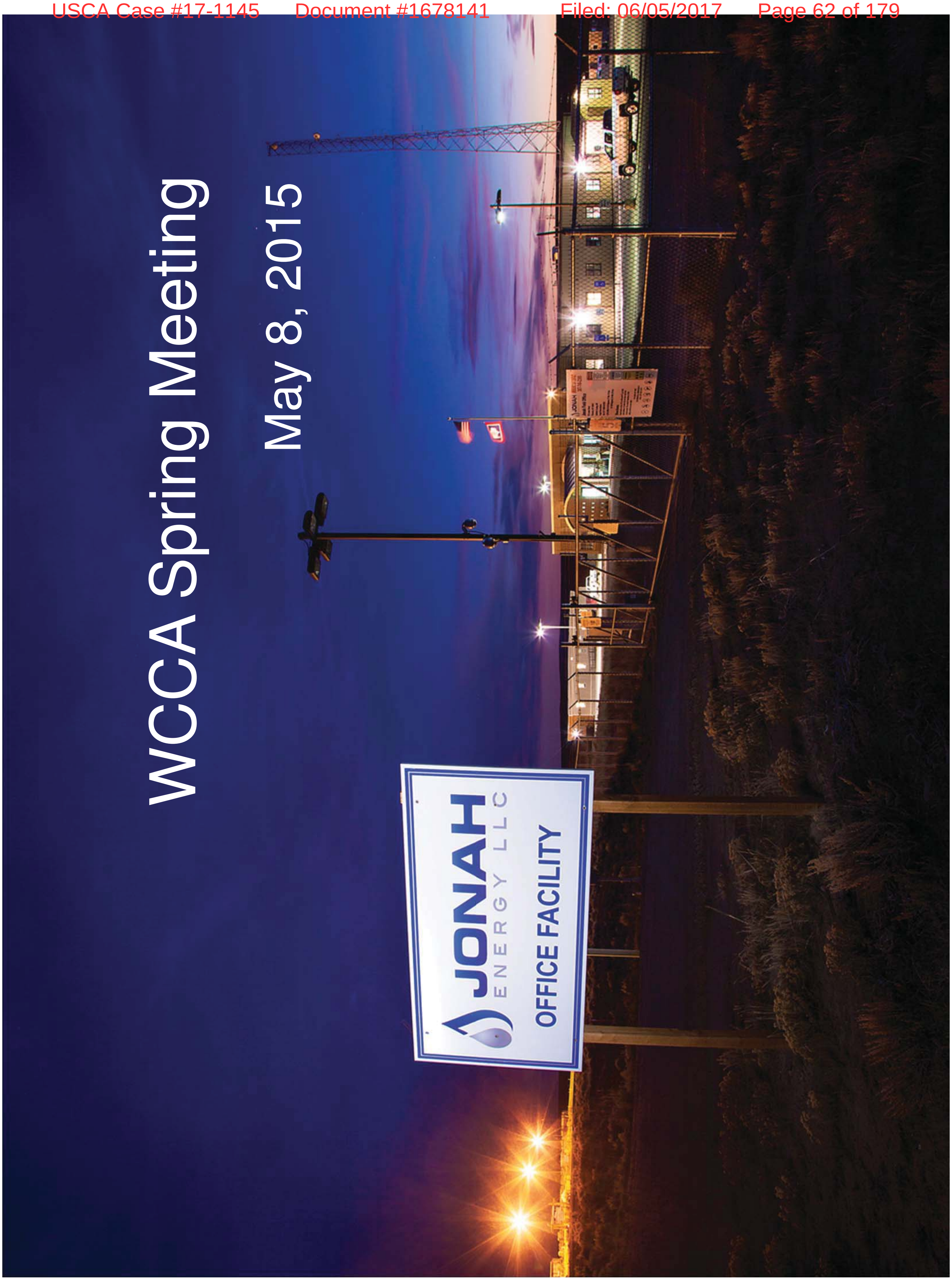
Karion, A.; Sweeney, C.; Kort, E. A.; Shepson, P. B.; Brewer, A.; Cambaliza, M. O. L.; Conley, S.; Davis, K. J.; Deng, A.; Hardesty, M.; Herndon, S. C.; Lauvaux, T.; Lavoie, T.; Lyon, D. R.; Newberger, T.; Petron, G.; Rella, C.; Smith, M.; Wolter, S.; Yacovitch, T.; Tans, P. (2015). Aircraft-based estimate of total methane emissions from the Barnett Shale region. *Environmental Science & Technology*, 49, DOI: 10.1021/acs.est.5b00217.

Yacovitch, T. I.; Herndon, S. C.; Pétron, G.; Kofler, J.; Lyon, D. R. ; Zahniser, M. S.; Kolb, C. E. (2015). Mobile Laboratory Observations of Methane Emissions in the Barnett. *Environmental Science & Technology*, 49, DOI: 10.1021/es506352j.

Lavoie, T. N.; Shepson, P. B.; Cambaliza, M. O. L.; Stirm, B. H.; Karion, A.; Sweeney, C.; Yacovitch, T. I.; Herndon, S. C.; Lan, X.; Lyon, D. R. (2015). Aircraft-Based Measurements of Point Source Methane Emissions in the Barnett Shale Basin. *Environmental Science & Technology*, 49, DOI: 10.1021/acs.est.5b00410.

Harriss, R.; Alvarez, R. A.; Lyon, D. R.; Zavala-Araiza, D.; Nelson, D.; Hamburg, S. P. (2015). Using Multi-Scale Measurements to Improve Methane Emission Estimates from Oil and Gas Operations in the Barnett Shale Region, Texas. *Environmental Science & Technology*, 49, DOI: 10.1021/acs.est.5b02305.

EXHIBIT B


WCCA Spring Meeting
May 8, 2015
JONAH
ENERGY LLC
OFFICE FACILITY

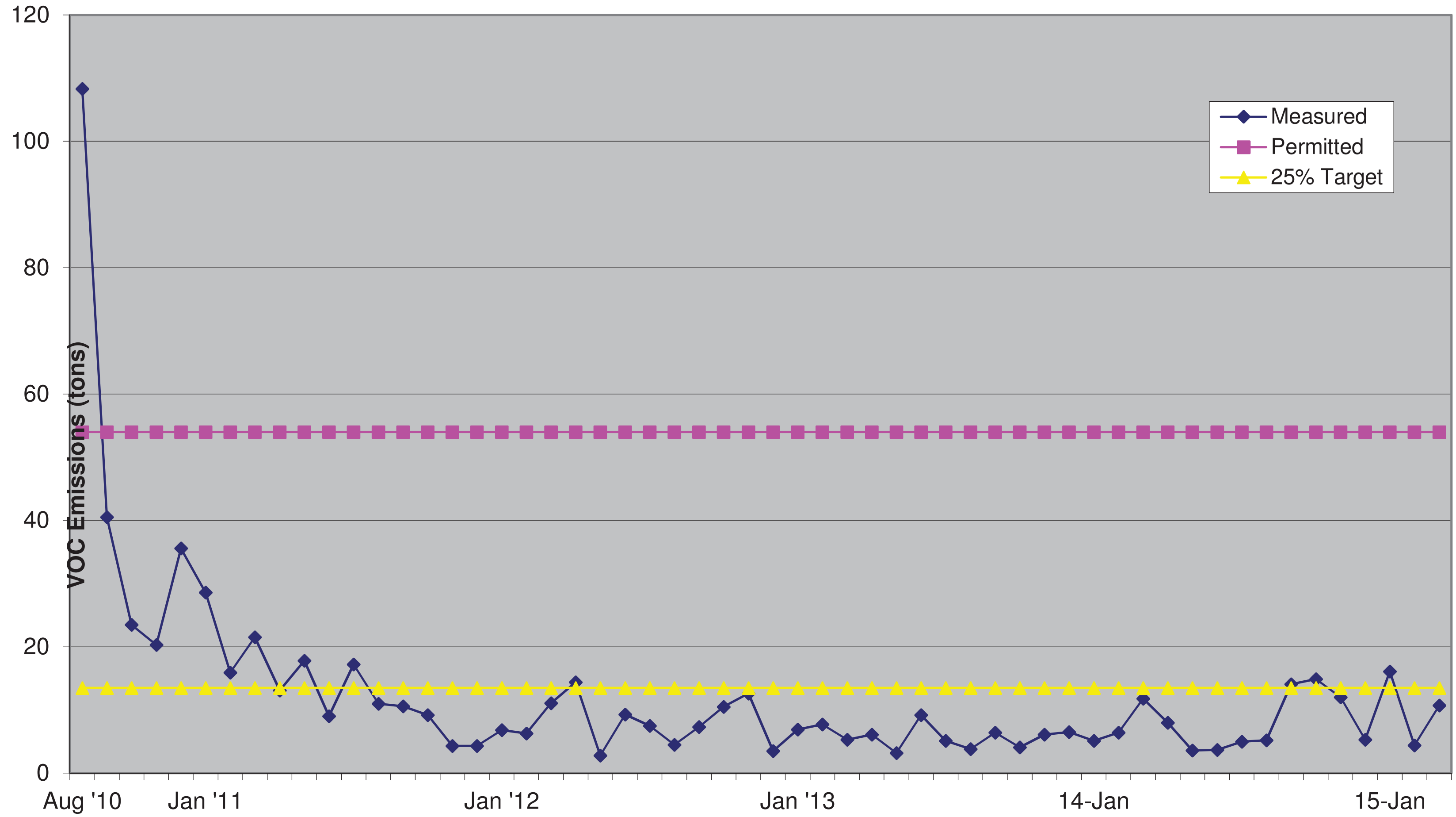
EDI&M Program

- Production equipment leak detection and repair
- Reduction of fugitive emissions
  - – VOC's & GHG emissions
- FLIR facilities once per month
- Reduce sales gas loss
- Enforceable by WDEQ
- 5 ½ years in
- 4 person team 7 days a week

JONAH ENERGY LLC

EDI&M Results

Exceeded a 75% reduction goal in VOC's



JONAH ENERGY LLC

EDI&M Results

12 Month Total	1st Year	2011	2012	2013	2014	2015
# of Inspections	3303	3473	4187	3847	2964	885
Leaks identified	2959	2159	2086	1947	1330	460
Repair Time (hr)	704.9	401.8	357.4	246.5	190	106
Labor Cost ($)	$58,369	$37,125	$31,109	$18,249	$15,984	$7,586
Material Cost ($)	$266,963	$186,884	$142,884	$100,381	$70,246	$17,077
Gas Savings ($/yr)*	$347,491	$234,964	$264,570	$159,886	$114,921	$20,526
VOC Emissions (tons)**	351	163	97	70	95	31.3

JONAH ENERGY LLC

Attachment 6

Declaration of Dr. Elena Craft, Environmental Defense Fund

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

DECLARATION OF DR. ELENA CRAFT

I, Dr. Elena Craft, declare:

1. I am a Senior Scientist at Environmental Defense Fund ("EDF"), a non-profit organization focused on protecting human health and the environment from airborne contaminants by using sound science. I received a Ph.D. in toxicology from Duke University's Nicholas School of the Environment and Earth and Ocean Sciences. I also have a Master of Science degree in Toxicology from N.C. State University.

2. As a Senior Scientist in Texas, I work to assess health impacts associated with living in close proximity to oil and gas development, and I also help to formulate and implement science-based strategies to reduce air pollution from oil and gas drilling activities. I have provided expert testimony at two House Congressional hearings related to issues of air quality, and ozone specifically. Currently, I am serving on various advisory committees to EPA, including the Mobile Source Technical Review Subcommittee (MSTRS) under the Clean Air Act Advisory Committee (CAAAC), as well as the Air, Climate, and Energy Subcommittee of the Board of Scientific Counselors. In addition, I have served

previously on committees including an Environmental Justice Technical Review Subcommittee and a ports work group.

The 2016 Rule

3. The oil and natural gas sector is the nation's largest industrial source of methane. Based on EPA's most recent data, [1] these sources account for almost 10 million metric tons of methane, or approximately 33 percent of the nation's total annual methane emissions. These sources also account for substantial emissions of smog-forming volatile organic compounds ("VOCs") and toxic air pollutants like benzene.

4. I am aware that the 2016 rule, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," 81 Fed. Reg. 35,824 (June 3, 2016) ("2016 Rule"), is projected to reduce methane emissions by 300,000 tons in 2020, and reduce ozone-forming emissions of "VOCs" by 150,000 tons by 2020. The standards will also reduce toxic contaminants like benzene, a known human carcinogen, cutting 1,900 tons of hazardous air pollutants in 2020.

5. In particular, the leak detection and repair ("LDAR") provisions of the 2016 Rule, which EPA has now stayed, will secure substantial reductions. EPA's

---

[1] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014* (2016) ("2014 GHGI"), at ES-13, Figure ES-8, *available at* https://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2016-Main-Text.pdf ("Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2014 with 176.1 MMT CO_2 Eq. of CH_4").

Regulatory Impact Analysis projects that these provisions alone will result in over 50 percent of the methane reductions, nearly 90 percent of hazardous air pollution reduction, and substantial VOC reductions in 2020.

6. Moreover, an analysis completed by Dr. David Lyon and submitted in a separate declaration identifies over 11,000 producing wells in states without state-level leak detection and repair requirements. These sources would have been required to perform LDAR surveys by June 3, 2017 and to repair any leaks within 30 days after that absent EPA's stay of those provisions. Dr. Lyon's analysis estimates that as a result of EPA's actions to stay the NSPS, these wells will emit approximately an additional 4,000-17,000 tons of methane, 1,100-4,700 tons of VOCs, and 45-180 tons of HAPs.

VOCs Are Harmful Air Pollutants That Form Ground-Level Ozone or Smog

7. Ozone forms when VOCs and oxides of nitrogen (NOX) react in the presence of heat and sunlight. This process becomes more pronounced in the summertime.

8. A longstanding body of scientific research, including numerous EPA assessments, demonstrates that exposure to ozone harms human health. For example, EPA's most recent Integrated Science Assessment for Ozone concluded a causal relationship or likely causal relationship between short- and long-term ozone exposure and a broad range of harmful respiratory and cardiovascular effects

in humans.[2] In addition, there is likely to be a causal relationship between short-term ozone exposure and non-accidental and cardiopulmonary-related mortality.

9. Ozone is particularly harmful to people with respiratory diseases or asthma, children, older adults, and people who are active outdoors, especially outdoor workers. Ozone exposure is associated with respiratory morbidity such as asthma attacks, increases in hospital and emergency department visits, and loss of school days, as well as with premature mortality. Even short-term exposure to ozone can have critical health implications. There is strong evidence of an association between out-of-hospital cardiac arrests and short-term exposure to ozone, as reported in Raun et al., 2013.[3] Time scales of exposure up to three hours in duration and also at the daily level on the day of the event were significant. This evidence augments the growing body of literature demonstrating the short-term impacts of ozone pollution. The 2016 Rule recognizes these adverse impacts, noting that "[r]esearchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies."[4]

10. In 2015, EPA strengthened the national health-based standard for ozone, lowering the standard from 75 parts per billion ("ppb") to 70 ppb.[5] The

---

[2] *See* U.S. EPA. *2013 Final Report: Integrated Science Assessment of Ozone and Related Photochemical Oxidants* at 1-5–1-8, Table 1-1 (EPA/600/R-10/076F).

[3] Katherine B. Ensor *et al*, *A Case-Crossover Analysis of Out-of-Hospital Cardiac Arrest and Air Pollution*, https://www.ncbi.nlm.nih.gov/pubmed/23406673.

[4] *Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources* at 4-25 (EPA-452/R-16-002, May 2016) ("RIA").

[5] EPA, *National Ambient Air Quality Standards for Ozone*, 80 Fed. Reg. 65292 (Oct. 26, 2015).

record for that rulemaking, however, along with subsequent scientific studies, demonstrates that health effects can occur at much lower levels, especially in sensitive populations. For that reason, EPA's independent scientific advisors recommended that the agency establish the standard in the range of 60-70 ppb. Many health and medical associations suggested that lower standards may be appropriate.[6] EPA is in the process of considering which areas of the country meet or exceed this revised, strengthened standard.

11. In addition to these formal designations, which are based on the 3-year average of the fourth-highest daily ozone air quality monitoring readings, particular areas of the country experience unhealthy levels of air quality on a daily basis. These unhealthy levels of ozone air quality can result in acute respiratory illness and other damaging health outcomes. To help alert the public about these unhealthy conditions, EPA maintains the Air Now database, a searchable, publicly-accessible database that characterizes daily air quality in particular areas of the country based on the threats posed by air pollution. For ozone, the agency has identified the following threat levels: green (good), yellow (moderate), orange (unhealthy for sensitive groups), red (unhealthy), purple (very unhealthy), and maroon (hazardous).

[6] *Id.* at 65321-23; 65355.

The Oil and Natural Gas Sector Is a Substantial Source of Smog-Forming Emissions

12. The oil and natural gas sector is a substantial source of smog-forming emissions. According to EPA's most recent National Emissions Inventory (NEI), "Petroleum & Related Industries" is the second largest source of VOCs nationally.[7] Regional analyses likewise underscore the significant ozone-forming emissions from these sources, including work in the Uinta Basin in Utah,[8] the Barnett Shale in Texas,[9] and in Colorado.[10]

13. Studies and analyses have linked ozone formation to emissions from oil and gas development. For example, a recent study by NOAA Scientists at the Cooperative Institute for Research in Environmental Sciences ("CIRES") found that, on Colorado's Northern Front Range, oil and gas operations contribute roughly 50% to regional VOC reactivity and that these activities are responsible

---

[7] EPA, National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data, https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data.

[8] Warneke, C. et al., "Volatile organic compound emissions from the oil and natural gas industry in the Uintah Basin, Utah: oil and gas well pad emissions compared to ambient air composition," 14 Atmos. Chem. Phys., 10977–10988 (2014), *available at* www.atmos-chem-phys.net/14/10977/2014/; ENVIRON, "Final Report: 2013 Uinta Basin Winter Ozone Study," (March 2014), *available at* https://deq.utah.gov/locations/U/uintahbasin/ozone/docs/2014/06Jun/UBOS2013FinalReport/Title_Contents_UBOS_2013.pdf.

[9] David T. Allen, "Atmospheric Emissions and Air Quality Impacts from Natural Gas Production and Use," Annu. Rev. Chem. Biomol. Eng. 5:55–75 (2014), *available at* http://www.annualreviews.org/doi/abs/10.1146/annurev-chembioeng-060713-035938.

[10] Brantley, et al., "Assessment of volatile organic compound and hazardous air pollutant emissions from oil and natural gas well pads using mobile remote and onsite direct measurements," Journal of the Air & Waste Management Association 1096-2247 (Print) 2162-2906 (Online) (2015); Pétron, G., et al., "A new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin," 119 J. Geophys. Res. Atmos., 6836–6852 (2014), *available at* http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/full.

for approximately 20% of all regional ozone production.[11] Another study analyzing ozone impacts associated with unconventional natural gas development in Pennsylvania concluded that "natural gas emissions may affect compliance with federal ozone standards,"[12] and an analysis in the Haynesville Shale in Texas found that emissions from the oil and gas sector could be responsible for as much as a 5 ppb increase in 8-hour ozone design levels for projected future productions.[13] There are also well-documented connections between oil and gas development and ozone formation in Wyoming's Upper Green River Basin and Utah's Uinta Basin, among others.

EPA's Stay of the 2016 Rule's LDAR Provisions Will Allow Additional, Harmful Ozone-Forming Emissions

14. Analysis completed by Dr. David Lyon and attached in a separate declaration found that 1,831 newly-drilled or -modified producing wells, which would have been required to perform leak detection and repair but for EPA's stay,

---

[11] McDuffie, E. E., et al. (2016), Influence of oil and gas emissions on summertime ozone in the Colorado Northern Front Range, J. Geophys. Res. Atmos., 121, 8712–8729, doi:10.1002/2016JD025265. http://onlinelibrary.wiley.com/doi/10.1002/2016JD025265/abstract. *See also* Gilman, J. B., B. M. Lerner, W. C. Kuster, and J. A. de Gouw (2013), Source signature of volatile organic compounds from oil and natural gas operations in northeastern Colorado, Environ. Sci. Technol., 47(3), 1297–1305, doi:10.1021/es304119a.http://pubs.acs.org/doi/abs/10.1021/es304119a (finding 55% of VOC reactivity in the metro-Denver area is due to nearby O&NG operations and calling these emissions a "significant source of ozone precursors.")

[12] Swarthout, R. F., R. S. Russo, Y. Zhou, B. M. Miller, B. Mitchell, E. Horsman, E. Lipsky, D. C. McCabe, E. Baum, and B. C. Sive (2015), Impact of Marcellus Shale natural gas development in southwest Pennsylvania on volatile organic compound emissions and regional air quality, Environ. Sci. Technol., 49(5), 3175–3184, doi:10.1021/es504315f
https://www.ncbi.nlm.nih.gov/pubmed/25594231

[13] Kemball-Cook, S., A. Bar-Ilan, J. Grant, L. Parker, J. Jung, W. Santamaria, J. Mathews, and G. Yarwood (2010), Ozone impacts of natural gas development in the Haynesville Shale, Environ. Sci. Technol., 44(24), 9357–9363, doi:10.1021/es1021137.
https://www.ncbi.nlm.nih.gov/pubmed/21086985

are located in areas that are not in attainment with the 2008 ozone standard. The analysis finds that up to an additional 832 tons of VOCs are likely to be emitted from these sources. While EPA has not yet finalized designations for the new, more protective 2015 standard, that standard will require reductions in pollutants from a broader set of counties, likely including additional counties with oil and gas wells that would be subject to the NSPS.

15. In addition to these formal nonattainment designations, counties with NSPS affected wells have experienced numerous, unhealthy ozone air quality days, according to data obtained from the Air Now database. Thus far, though the 2017 ozone season has just begun, counties with wells that would be subject to the NSPS have experienced 1,256 moderate days (yellow flag warning), 49 days unhealthy for sensitive groups (orange flag warning), 2 unhealthy days (red flag warning), and 1 very unhealthy or hazardous day (purple flag warning). During the 2016 ozone season, counties with wells that would be subject to the NSPS experienced 7,832 moderate days (yellow flag warning), 549 days deemed unhealthy for sensitive groups (orange flag warning), 94 unhealthy days (red flag warning), and 6 very unhealthy and hazardous days (purple flag warning).

16. Many Americans live in these counties with both unhealthy levels of ozone pollution and new or modified wells for which EPA has now stayed requirements that would reduce this pollution. For example, analysis included in

an Environmental Defense Fund membership declaration submitted by John Stith finds that EDF has over 30,000 members who live in counties that have affected NSPS wells and are designated nonattainment for the 2008 national ambient air quality standards for ozone.

17. EPA's stay of the LDAR requirements will allow additional emissions of smog-forming pollutants in these areas already burdened with unhealthy levels of ozone pollution. EPA's stay will cover at least the months of June, July, and August, adding pollutants during the summertime, when ozone formation is more pronounced and when people are more likely to be engaged in outdoor activities. This added pollution enhances the risk of near-term harm to children, older adults, those suffering from respiratory diseases such as asthma, low income populations, outdoor workers, and others recreating outdoors.

Oil and Natural Gas Operations Emit Hazardous Air Pollutants like Benzene, a Known Human Carcinogen

18. Oil and natural gas operations also emit hazardous air pollutants ("HAPs"), such as benzene. In the RIA, EPA found that several different HAPs are emitted from oil and gas operations, "either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks."[14] EPA also found that emissions of eight HAPs make up the largest percentage of the total HAP emissions from the oil and gas sector, including "toluene, hexane, benzene, xylenes

[14] RIA at 4-33.

(mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane."[15] EPA estimates that the 2016 rule would reduce 3,400 tons of HAPs in 2025.[16]

19. There is no safe level of human exposure to many of these toxic pollutants. Exposure to HAPs can cause cancer and seriously impair the human neurological system. Benzene, for example, found naturally in oil and gas, is a "known human carcinogen (causing leukemia) by all routes of exposure, and . . . that exposure is associated with additional health effects, including genetic changes in both humans and animals."[17]

20. Further, a "number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene."[18] Along with benzene, EPA also catalogued the harmful effects of other specific air toxics emitted from oil and gas, including toluene, carbonyl sulfide, ethylbenzene, mixed xylenes, n-hexane, and other air toxics.[19] Each of these hazardous pollutants is harmful to human health. For example, the serious health effects associated with exposure to toluene range from the dysfunction of the central nervous system to narcosis, with effects

---

[15] *Id.*
[16] *Id.*
[17] *Id.*
[18] *Id.* at 3-34.
[19] *See id*. 4-33- 4-37.

"frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation."[20]

21. Dr. Lyon's analysis suggests that between 45 and approximately 180 tons of these damaging pollutants will now be emitted by sources subject to the stay. Many Americans live in very close proximity to these wells, including members of organizations challenging EPA's stay. For example, an analysis included in an Environmental Defense Fund membership declaration submitted by John Stith finds that EDF has 14 members who live within a quarter mile of wells subject to the stay. The analysis identifies over 200 members who live within a mile of these sources and over 9,000 members who live within 10 miles of these sources, all in states that lack any state-level leak detection and repair requirements. These members and many other Americans will be exposed to additional hazardous air pollutants, increasing their risk of experiencing adverse health outcomes.

Recent Studies Suggest Proximity to Oil and Gas Development is Associated with Adverse Health Outcomes.

22. In addition to the threats to public health posed by exposure to HAPs and ozone, new studies document associations between proximity to nonconventional oil and gas development and human health effects. While these

[20] *Id.*

studies do not evaluate concentrations of specific air pollutants, they do document health effects that are consistent with exposure to smog and hazardous air pollutants.

23. Air pollutants associated with oil and gas operations are known to cause serious health impacts in sensitive populations such as pregnant women, babies, and children. Studies have documented that living near natural gas wells is associated with lower birth weight babies[21] and preterm birth.[22] Another study found an association between oil and gas proximity and congenital heart defects in infants.[23] Babies whose mothers had large numbers of natural gas wells within a 10-mile radius of their home had an increased risk of birth defects of the heart, compared to babies whose mothers had no wells within 10 miles of their home.[24]

24. Other studies also document correlations between proximity to oil and gas drilling and human health effects in otherwise healthy populations. This emerging body of scientific literature includes several new studies documenting negative human health impacts based on proximity to oil and gas wells. For example, a study from 2016 demonstrated that oil and gas well proximity was correlated with an increase in the likelihood of asthma exacerbations, including

---

[21] *See* Stacy, et al., *Perinatal Outcomes and Unconventional Natural Gas Operations in Southwest Pennsylvania*, PLoS ONE (June 3, 2015) *available at* https://doi.org/10.1371/journal.pone.0126425.
[22] Casey et al., *Unconventional Natural Gas Development and Birth Outcomes in Pennsylvania, USA,* Epidemiology (March, 2016) *available at* https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4738074/.
[23] McKenzie et. al., *Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado,* Env. Health Perspectives (Jan. 28, 2014) *available at* https://ehp.niehs.nih.gov/1306722/.
[24] *Id*.

mild, moderate, and severe asthma attacks.[25] A 2015 study documented increased hospitalization rates in counties with a high density of oil and gas wells.[26] Similarly, other studies, including a 2017 study, have demonstrated an increase in the reporting of nasal, sinus, and migraine headaches, and fatigue symptoms in areas with high volumes of oil and gas drilling.[27]

25. While this literature is developing, it helps to substantiate that people living in close proximity to oil and gas development are exposed to air pollution from these sources and experience acute, adverse, and often near-term health impacts.

Conclusion

26. EPA's decision to stay leak detection and repair requirements in the 2016 Rule will result in additional VOC and HAP emissions. Individuals exposed to these emissions face a higher risk of adverse health effects, including acute and immediate respiratory ailments like asthma and enhanced risk of longer term, deleterious health effects associated with toxic pollution exposures.

I declare that the foregoing is true and correct.

---

[25] Rasmussen et al, *Association between Unconventional Natural Gas Development in the Marcellus Shale and Asthma Exacerbations,* 176 J. Am. Med. Assn. Internal Med. 1334-43. (Sept., 2016) *available at* https://www.ncbi.nlm.nih.gov/pubmed/27428612.

[26] Jemielita et al., *Unconventional Gas and Oil Drilling Is Associated with Increased Hospital Utilization Rates,* PLoS ONE (July 15, 2015) *available at* https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4503720/.

[27] *See* Tustin et al., *Associations between Unconventional Natural Gas Development and Nasal and Sinus, Migraine Headache, and Fatigue Symptoms in Pennsylvania,* 125 ENV. HEALTH PERSPECTIVES 189 (Feb., 2017) *available at* https://ehp.niehs.nih.gov/EHP281/.

Elena Craft, PhD

Dated June 3, 2017

Attachment 7

Declaration of Ilissa B. Ocko, Environmental Defense Fund

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

DECLARATION OF ILISSA B. OCKO
Submitted In Support of Environmental Defense Fund

I, Ilissa B. Ocko, declare as follows:

1. I am a Climate Scientist at the Environmental Defense Fund ("EDF"). I earned a Ph.D. in Atmospheric and Oceanic Science from Princeton University, where I studied the impact of human-emitted greenhouse gases (including methane) and aerosols on Earth's radiative balance and the climate using observational and global climate model-derived datasets. I have written several peer-reviewed papers on the impacts of short-lived climate pollutants on radiative forcing, air temperature, hydrological patterns, and atmospheric and oceanic circulation. My curriculum vitae is attached as Exhibit A.
2. I joined EDF in 2013. At EDF, my work focuses on analyzing the temperature impacts of various climate change mitigation strategies. I use all forms of analytical tools to evaluate climate effects, from simple metrics to reduced-complexity models to sophisticated global climate models. I also lead an effort to improve simple metrics (i.e. Global Warming Potential) in

climate policy applications by making temporal tradeoffs transparent;[1] I work with scientists, government agencies, industries, and nonprofits to advance this effort. I specifically aim to enhance public understanding of climate impacts over all timescales, both near- and long-term.

3. Methane is a considerable driver of near-term climate change, responsible for a quarter of the warming we are experiencing today.[2] A quarter of global human-emitted methane comes from the oil and gas sector, which is the largest industrial source of methane emissions in the United States.[3] My research includes determining how to slow the rate of global warming via methane emissions reductions. Of all methane sources from human activities, reducing leaks from oil and gas operations presents a unique, near-term opportunity considering its cost effectiveness, technological availability, and immediate impacts on climate.

4. For the same mass of CO_2 and methane emissions, methane can trap 120 times more energy than CO_2, both directly from methane as a greenhouse gas and indirectly from the creation of further greenhouse gases: tropospheric ozone, stratospheric water vapor, and CO_2. Over a twenty year

---

[1] Ocko, I.B., Hamburg, S.P., Jacob, D.J., Keith, D.W., Keohane, N.O., Oppenheimer, M., Roy-Mayhew, J.D., Schrag, D.P. and Pacala, S.W., *Unmask temporal trade-offs in climate policy debates*, 356(6337) SCIENCE 492-493 (2017).

[2] Calculation from Shindell et al. 2009 of fraction of total positive radiative forcing that methane emissions are responsible for; Shindell, D.T., Faluvegi, G., Koch, D.M., Schmidt, G.A., Unger, N. and Bauer, S.E., *Improved attribution of climate forcing to emissions*, 326(5953) SCIENCE 716-718 (2009).

[3] EPA GLOBAL ANTHROPOGENIC NON-CO2 GREENHOUSE GAS EMISSIONS: 1990-2030, https://www.epa.gov/global-mitigation-non-co2-greenhouse-gases/global-anthropogenic-non-co2-greenhouse-gas-emissions.

period, this number drops to 84 as methane is removed from the atmosphere more quickly than CO_2.

5. Further, through the creation of tropospheric ozone, methane contributes to ground-level ozone which is harmful to humans, and linked to short and long-term negative health effects including shortness of breath, decreased lung function, and chronic obstructive pulmonary disease (COPD). Ozone also aggravates existing cardiovascular and respiratory conditions, such as asthma, emphysema, and bronchitis, with long term exposure increasing the risk of death from these conditions.

6. Methane only lasts for approximately a decade in the atmosphere, because it is oxidized on average after 12.4 years, breaking down and forming other chemical species.[4] Methane reductions, therefore, can rapidly slow the rate of warming.[5]

7. It is crucial to limit both the rate of warming and long-term warming, in order to reduce warming impacts during our lifetimes and for generations to come. Both near-term and long-term warming are associated with specific

---

[4] Myhre, Gunnar et al., *Anthropogenic and Natural Radiative Forcing*, CLIMATE CHANGE 2013: THE PHYSICAL SCIENCE BASIS. CONTRIBUTION OF WORKING GROUP I TO THE FIFTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (2013), http://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf.

[5] Shoemaker, J.K., Schrag, D.P., Molina, M.J. and Ramanathan, V., *What role for short-lived climate pollutants in mitigation policy?,* 342(6164) SCIENCE 1323-1324 (2013); Shindell, D., Kuylenstierna, J.C., Vignati, E., van Dingenen, R., Amann, M., Klimont, Z., Anenberg, S.C., Muller, N., Janssens-Maenhout, G., Raes, F. and Schwartz, J., *Simultaneously mitigating near-term climate change and improving human health and food security*, 335(6065) SCIENCE 183-189 (2012).

sets of damages, and all must be reduced. Near-term warming impacts infrastructure, plant and animal species survival rates,[6] extreme events, and sea level rise.[7] Long-term warming impacts glacial melt, permafrost melt, tipping points, shifts in biomes, and more. Carbon dioxide is the main driver of long-term warming because of its long atmospheric lifetime.[8] However, reduction of carbon dioxide will not impact warming rates during our lifetime.[9] On the other hand, taking immediate steps to reduce emissions of methane are essential for limiting near-term warming.[10] Conversely, allowing near-term methane emissions to persist will accelerate warming.[11]

8. Warming to date has already negatively impacted every continent and every ocean,[12] and resulted in tropical island villages disappearing,[13] Arctic houses sinking,[14] coral reefs dissolving and dying,[15] mosquito seasons growing

---

[6] Settele, J. et al., *Terrestrial and Inland Water Systems,* CLIMATE CHANGE 2014: THE PHYSICAL SCIENCE BASIS. CONTRIBUTION OF WORKING GROUP II TO THE FIFTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (2014), http://www.ipcc.ch/pdf/assessment-report/ar5/wg2/WGIIAR5-Chap4_FINAL.pdf.
[7] Hu, A., Xu, Y., Tebaldi, C., Washington, W.M. and Ramanathan, V., *Mitigation of short-lived climate pollutants slows sea-level rise*, 3 NATURE CLIMATE CHANGE 730 (2013).
[8] Myhre et al., *supra* note 4.
[9] Shoemaker et al., *supra,* note 5; Shindell et al., *supra* note 5.
[10] *Id.*
[11] *Id.*
[12] IPCC, CLIMATE CHANGE 2014 IMPACTS, ADAPTATION, AND VULNERABILITY, SUMMARY FOR POLICY MAKERS, http://www.ipcc.ch/pdf/assessment-report/ar5/wg2/ar5_wgII_spm_en.pdf.
[13] Albert, S., Leon, J.X., Grinham, A.R., Church, J.A., Gibbes, B.R. and Woodroffe, C.D., *Interactions between sea-level rise and wave exposure on reef island dynamics in the Solomon Islands*, 11(5) ENVIRONMENTAL RESEARCH LETTERS 054011 (2016).
[14] ALASKA CLIMATE CHANGE IMPACT MITIGATION PROGRAM, https://www.commerce.alaska.gov/web/dcra/planninglandmanagement/accimp.aspx.
[15] Muehllehner et al., *Dynamics of carbonate chemistry, production, and calcification of the Florida Reef Tract (2009-2010): Evidence for seasonal dissolution,* 30(5) GLOBAL BIOGEOCHEMICAL CYCLES 661, 661-688 (2016); ONLY 7% OF THE GREAT BARRIER REEF HAS AVOIDED CORAL BLEACHING, http://www.coralcoe.org.au/media-releases/only-7-of-the-great-barrier-reef-has-avoided-coral-bleaching.

weeks longer,[16] and worsened extreme heat events yielding high death tolls.[17] Continuing methane emissions will likely result in more pronounced impacts in the future. Further warming also enhances the risk that the climate surpasses irreversible tipping points that could render long-term climate stabilization difficult or impossible.[18]

9. Reducing emissions of methane will also help to limit sea level rise. Ninety percent of heat that is trapped in the atmosphere gets absorbed by the oceans (IPCC 2013). While methane only lasts for about a decade in the atmosphere, a substantial fraction of the atmospheric heating that methane causes during this period is absorbed by the oceans, where the warming signal lasts far longer than in the atmosphere. Accordingly, near-term methane emissions can cause sea level rise for decades to come.[19] I am aware that the 2016 rule, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," 81 Fed. Reg. 35824 (June

---

[16] Muehllehner et al., *Dynamics of carbonate chemistry, production, and calcification of the Florida Reef Tract (2009-2010): Evidence for seasonal dissolution,* 30(5) GLOBAL BIOGEOCHEMICAL CYCLES 661, 661-688 (2016); ONLY 7% OF THE GREAT BARRIER REEF HAS AVOIDED CORAL BLEACHING, http://www.coralcoe.org.au/media-releases/only-7-of-the-great-barrier-reef-has-avoided-coral-bleaching.

[17] EXPLAINING EXTREME EVENTS FROM A CLIMATE PERSPECTIVE, https://www.ametsoc.org/ams/index.cfm/publications/bulletin-of-the-american-meteorological-society-bams/explaining-extreme-events-from-a-climate-perspective/; WORLD WEATHER ATTRIBUTION, https://wwa.climatecentral.org/analyses/.

[18] Lenton, T.M., Held, H., Kriegler, E., Hall, J.W., Lucht, W., Rahmstorf, S. and Schellnhuber, H.J., *Tipping elements in the Earth's climate system*, 105(6) PROCEEDINGS OF THE NATIONAL ACADEMY OF SCIENCES 1786-1793 (2008).

[19] Hu et al., *supra* note 7.

3, 2016), is projected to reduce methane emissions by 300,000 tons in 2020 and 510,000 tons in 2025.

10. I am also aware that, in a separate declaration, Dr. David Lyon has calculated that EPA's 90-day stay of the leak detection and repair provisions of the 2016 rule would allow 17,204 tons of methane to be emitted over the course of the stay from producing wells in states that otherwise lack state level LDAR requirements. This is equivalent to the 20-year climate impact of over 300,000 passenger vehicles driving for one year or over 1.5 billion pounds of coal burned. These impacts will be even greater if the stay is extended beyond 90 days, as EPA has indicated is its intention. Once released, these emissions cannot be removed from the atmosphere and will contribute to both near- and longer-term climate damages, including impacts associated with an increased rate of warming, sea level rise, and others.

I declare that the foregoing is true and correct.

Ilissa B. Ocko

Dated June 2, 2017

Attachment 8

Press Release, U.S. EPA, EPA Stays Oil and Gas Standards (May 31, 2017)

News Releases from Headquarters › Air and Radiation (OAR)

EPA Stays Oil and Gas Standards

05/31/2017

Contact Information:
(press@epa.gov)

WASHINGTON – The U.S. Environmental Protection Agency (EPA) is following through on its commitment to stay portions of the 2016 New Source Performance Standards for the oil and natural gas industry while the agency works through the reconsideration process.

Using its Clean Air Act authority, the agency is issuing a 90-day stay of the fugitive emissions, pneumatic pumps, and professional engineer certification requirements from the 2016 rule. Sources do not need to comply with these requirements while the 90-day stay is in effect. EPA's action is in line with President Trump's Energy Independence Executive Order, which directed the agency to review the oil and gas rules.

In June 2016, EPA issued updated standards for new, reconstructed and modified oil and gas sources. Since issuing the final rules last year, EPA has received several petitions to reconsider aspects of the New Source Performance Standards. In an April 18, 2017 letter to petitioners, the agency announced its intent to reconsider certain aspects of the rule, including the fugitive emissions requirements. This action also grants reconsideration and stays for 90 days the pneumatic pump and professional engineer certification requirements in the rule.

As part of the reconsideration process, EPA expects to prepare a proposed rule, which will allow for public comment. Additional information on the stay and reconsideration: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

R100

LAST UPDATED ON MAY 31, 2017

Attachment 9

API, Request for Administrative Reconsideration: EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources" (Aug. 2, 2016) (excerpts) energy API

Howard J. Feldman
Senior Director, Regulatory and Scientific Affairs

1220 L Street, NW
Washington, DC 20005-4070
USA

202-682-8340
Feldman@api.org
www.api.org

August 2, 2016

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources"

Dear Administrator McCarthy:

The American Petroleum Institute ("API") hereby submits this petition for administrative reconsideration of the final rule entitled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," published at 81 Fed. Reg. 35824 (June 3, 2016) ("Subpart OOOOa").

Pursuant to section 307(d)(7)(B) of the Clean Air Act ("CAA"), 42 U.S.C. § 7607(d)(7)(B), where it is impracticable to raise an objection during the period of public comment or if the grounds for such an objection arise after the public comment period (but within the time specified for judicial review), and if such objections are of central relevance to the outcome of the rule, the U.S. Environmental Protection Agency ("EPA" or "Agency") is required to reconsider a rule.

API represents over 650 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Most of our members conduct oil and gas development and production operations and, thus, will be directly impacted by this final rule.

This document is divided into two parts. In the first part, we present the issues for which we believe that administrative reconsideration is warranted. In the second part, we present a number of additional issues where we believe changes to the rule are needed, but where we are not asking for administrative reconsideration. These additional issues are included because we believe it would be efficient for EPA to make these changes in the rulemaking that the Agency undertakes to accomplish administrative reconsideration of the first set of issues

We look forward to continuing to work with the Agency on improving the rule and are submitting this request for reconsideration to address a number of key issues identified in the finalized rule.

Thank you for your consideration of this request for administrative reconsideration. Please do not hesitate to contact me (202.682.8340) if you have questions or need more information.

Sincerely,

Howard J. Feldman

CC: Janet McCabe, EPA
Steve Page, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA

API Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources"

August 2, 2016

Table of Contents

I. ISSUES FOR WHICH WE REQUEST ADMINISTRATIVE RECONSIDERATION

1. The requirements for Certification by Professional Engineer finalized in §60.5411a(d) for closed vent systems and §60.5393a for pneumatic pump technical infeasibility determination at brownfield sites should be removed and stayed pending reconsideration.

The final rule includes requirements for a professional engineer (PE) to certify closed vent system designs for storage vessels and centrifugal compressors as well as certify when it is not possible to control an affected pneumatic pump at a brownfield site. The provisions requiring PE certification were not included in the proposed rule and should be reconsidered, given the inability to raise an objection during the public comment period, and stayed pending reconsideration to allow a full notice and comment process. Comments presented here would have been provided to EPA during the proposal comment period, if we were provided proper notice and comment ability. Our objection is of central relevance to the outcome of the rule because it provides substantial support for the need to revise the rule to eliminate the PE certification requirement.

Companies will be burdened with the additional costs and project delays for a third party PE to design and certify closed vent systems as few companies have an adequate staff of in-house PEs. While API appreciates EPA's recognition of some of the challenges of having such PE reviews completed, including extending the compliance date for affected pneumatic pumps from 60 days to 180 days following publication, there are still fundamental problems with EPA's approach and no extension was provided for storage vessels and centrifugal compressors. Other issues associated with the requirement to have PE certification include the following:

- The PE certification process does not add any significant value and EPA has not justified the extra expense and burden of PE certifications when there are provisions in place for compliance report submittals approved by a certifying official.
  - There is already a 'general duty obligation' in § 60.11(d) for owners and operators to ensure proper operation, and maintenance of equipment. PE certification does not relieve companies of this duty.
  - The certifying official is already required to sign off on a company's compliance with all applicable provisions.
  - There is no quantifiable benefit to the environment from this additional review, while there is significant expense involved.
  - There are direct costs associated with the PE certification process, whether companies support in house licensure of engineers or leverage third parties. However, no costs associated with obtaining PE approval were considered or provided for review during the proposal process.
- Development of in-house PE capacity will take several years. Development of a sufficient number of in-house licensed PEs to cover all states where a company operates will take considerable time. Meanwhile, though EPA has determined third-party PE certification is unnecessary, many operators will have to depend heavily on outside consultant PEs in the foreseeable future. This will add additional cost and delays to projects that EPA has not accounted for.

- It takes at least four years of experience plus additional time to satisfactorily pass required testing to obtain a PE license.
- At present, most company engineers are not PEs, and PE licensure is not a condition of employment or career development. While trained and qualified and with years of experience in the design of production facilities, these engineers are not called upon to formally certify equipment designs.
- EPA's allowance of PEs not licensed in the state where certification is needed conflicts with state and PE licensure requirements that a PE must be licensed in the state where they practice. Consequently, a PE cannot ethically certify closed vent system design or technical infeasibility based on EPA's standard, which is inconsistent and contradictory to PE licensure rules of practice. This limitation invalidates the Subpart OOOOa definition of *Qualified Professional Engineer.*

Therefore, EPA should reconsider the PE certification requirement and remove it entirely from the rule to relieve the redundancy it creates relative to each company's existing general duty obligations and the certifying official's acknowledgment. At a minimum, EPA should broaden the requirements and allow alternatives to PE Certification such as to require all designs to undergo engineering review and approval. A general duty to properly design CVS or determine technical infeasibility should be adequate for enforcement.

An administrative stay of the PE certification requirement pending the outcome of the reconsideration proceeding is needed and justified because, even though the effective date of the requirement for affected pneumatic pumps has been extended to 180 days after publication of the rule, it is highly unlikely that EPA will complete reconsideration prior to that date. As a result, absent a stay, companies will confront the costs, uncertainties and compliance barriers described above – all of which can and should be avoided through amendment of the rule.

2. Coincident with PE certification requirements for pneumatic pump technical infeasibility determinations, EPA introduced but inadequately defined "greenfield" site as there is no clarity with respect to determining when a greenfield site transitions to a brownfield site. As well, it is inappropriate to categorically prohibit a claim of technical infeasibility for greenfield sites.

The terms "greenfield" and "brownfield" sites and the use of these terms in determining compliance obligations were not proposed. Therefore, industry had no opportunity to comment. In addition, this issue is of central relevance to the outcome of the rule because, for the reasons described below, changes to the final rule are needed. Consequently, administrative reconsideration of this issue is justified.

Without a clear definition with respect to the boundary of when greenfield ends and brownfield begins, operators will be put in an untenable situation if "greenfield" is considered synonymous with "new" for NSPS thereby removing future technical infeasibility determinations for the entire life of a well site. Initial design for construction of a greenfield site may not require installation of a pneumatic pump or a control device for the early operational period of a well site. At some point later in the life of a well (which could be years), site design requirements may change where a new control and/or pump is installed and a technical infeasibility determination is justified but not available if the site is considered greenfield throughout the life of the site. Even for a new site, process or control device design requirements may not be compatible with controlling pneumatic pump emissions.

For example, a new site design only requires installation of a high pressure flare to handle emergency and maintenance blowdowns. It may not be feasible for a low pressure pneumatic pump discharge to be routed to a high pressure flare.

Another and likely more common example would be if a new greenfield site design calls for installation of a pneumatic diaphragm pump but no control device is present. Rather, only a process heater or boiler is present. The design and operation of a given pneumatic pump and co-located process heater or boiler may not be compatible. The heater and boiler will be designed based on the process it needs to support without regard to the additional capacity or operational need to control a pneumatic pump. More specifically, due to the small size (generally 125,000 Btu per hour to 2.5 mmBtu per hour) of many heaters/boilers used at well sites, burner capacity may be insufficient to compensate for emission combustion of additional large pneumatic diaphragm pump discharge and may result in frequent safety trips and burner flame instability (i.e. high temperature limit shutdowns, loss of flame signal, etc.). Additionally, industry guidelines (i.e. NFPA 86) would prohibit the use of boilers/heaters as control devices where the following criteria are not met: the operating temperature being a minimum of 1400°F, presence of emission source safety interlocks, etc.

In summary, a process heater or boiler may only operate a few weeks or months per year or the fuel use rating of the heater may be insufficient to handle the additional capacity of a pump discharge or both. While this issue could be dealt with at “brownfield” sites as technically infeasible, there is no such allowance for this capacity issue at “greenfield” sites.

Without a technical infeasibility option, having to design and build a process heater or boiler around the capacity needs to adequately and safely control a pneumatic pump when it otherwise wouldn’t be designed with this feasibility in mind is equivalent to requiring installation of a new control device, and additional cost will unnecessarily be incurred. This concept is contradictory to the rule not requiring installation of a control device or process equipment for the sole purpose of controlling a pneumatic pump.

EPA should allow for technical infeasibility determinations at all well sites and not attempt to segregate sites by greenfield or brownfield. Use of greenfield and brownfield needs to be deleted from the rule. If the two terms remain, API recommends that EPA add a timeline which defines when “greenfield site” ends and brownfield begins. API believes brownfield begins after startup of production at new well sites.

3. Clarification is required regarding location of separator finalized in §60.5375a for well completion operations.

In NSPS OOOOa, a requirement was added in §60.5375a(a)(1)(iii) “*You must have a separator onsite during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section”* that was not included in the proposed regulation. Comments presented here would have been provided to EPA during the proposal comment period, if we were provided proper notice and comment ability. Our objection is of central relevance to the outcome of the rule because it provides support for the need to revise the rule to accurately reflect EPA's intent.

The rule does not provide a definition of "on-site". For wells that flow to centralized facilities or well pads, there will not be gas gathering or flowlines that go to the well head, only the centralized facility or well pad. Also, there would not be equipment located with the well to use the gas as fuel; therefore, there would be no where to send the recovered gas except to a flare.

In VI.E.1 of the Preamble to Subpart OOOOa, EPA discusses the issue of the requirement to have a separator onsite for subcategory 1 wells. An excerpt is provided here (emphasis added):

> *"… we do not have sufficient data to consistently and accurately identify the subcategory or types of wells for which these circumstances occur regularly or what criteria would be used as the basis for an exemption to the REC requirement such that a separator would not be required to be onsite for these specific well completions. In order to accommodate these concerns raised by commenters, the final rule requires a separator to be onsite during the entire flowback period for subcategory 1 wells (i.e., non-exploratory or non-delineation wells, also known as development wells), but does not require performance of REC where a separator cannot function. We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be* ***onsite or nearby, or that any separator brought onsite or nearby can be put to use.*** *For the reason stated above, we do not believe that requiring a separator onsite would incur cost with no environmental benefit."*

In the above discussion, it is clear that EPA recognizes the intent to allow use of a nearby separator as part of an inline or reduced emission completion. However, the requirement in §60.5375a((a)(iii) only references "separator onsite", which is inconsistent with EPA's intent that the separator does not necessarily have to be located on the specific wellsite in order to satisfy requirements of the rule.

EPA should amend the text in §60.5375a(a)(1)(iii) to also include reference to separators both onsite or nearby clarifying that operators may opt to use production separators at a nearby production site, and the separator does not need to be located at the specific well site being hydraulically fractured. EPA should update §60.5375a(a)(1)(iii) as noted below.

§60.5375a(a)(1)(iii):

> *You must have a separator onsite <u>or otherwise available for use nearby during the entirety of the flowback period.</u>*

4. The requirements in the final rule to document and report claims of technical infeasibility related to capturing of emissions during a well completion were not proposed and should be removed from the final rule.

Dating from the proposed edits to Subpart OOOO of July 17, 2014[1], EPA provided an additional three options for the disposition of flowback gas beyond routing to a gas flow line or collection system.

---

[1] 79 FR 41756

Specifically, Subpart OOOO has allowed for gas to also be *"re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve"*.

These three alternate options are very rarely utilized, if ever. API members are not aware of any scenarios where gas has been re-injected into the well undergoing hydraulically fracturing or injected into another well. Beyond that, these alternatives are not utilized because the gas is not of sufficient quality to rely on as onsite fuel source or raw material for another useful purpose.

API did not previously raise concerns with these alternatives when they were introduced in 2014 as they were only potential alternatives. However, under the recordkeeping requirement in §60.5420a (c)(1)(iii)(A), EPA finalized additional requirements.

§60.5375a in the Proposed Subpart OOOOa read:

> *(2) All salable quality recovered gas must be routed to the gas flow line as soon as practicable. In cases where salable quality gas cannot be directed to the flow line due to technical infeasibility, you must follow the requirements in paragraph (a)(3) of this section.*
>
> *(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source.*

When EPA finalized Subpart OOOOa, these two paragraphs of §60.5375a were revised to read:

> *(2) [Reserved]*
>
> *(3) If it is technically infeasible to route the recovered gas as required in § 60.5375a(a)(1)(ii), then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.*

Under the proposed language (and the language which preceded it in the rule), operators were authorized to route gas to a completion combustion device if salable quality gas could not be directed to the flow line due to technical infeasibility. Optionally, operators could also re-inject gas into the well or another well, use the gas as an onsite fuel source, or use it for another useful purpose that a purchased fuel or raw material would serve.

Under the finalized language, operators must try all four options provided by EPA prior to routing gas to a completion combustion device and also document the infeasibility of each of the four options as described below.

The text in red in the excerpt below was not in the proposed rule, but was added to the final version of the rule.

§60.5420a (c)(1)(iii)(A):

> *For each well affected facility required to comply with the requirements of §60.5375a(a), you must record: The location of the well; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under §60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (i.e., routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas to any of the four options specified in §60.5375a(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in that subparagraph, including but not limited to; name and location of the nearest gathering line and technical considerations preventing routing to this line; capture, reinjection, and reuse technologies considered and aspects of gas or equipment preventing use of recovered gas as a fuel onsite; and technical considerations preventing use of recovered gas for other useful purpose that that a purchased fuel or raw material would serve.*

The comments presented here would have been provided to EPA during the proposal comment period, if we were provided proper notice and comment ability. Our objection is of central relevance to the outcome of the rule because it provides substantial support for the need to revise the rule.

API believes there is a burden from the final rule language that was not considered during the proposal. More importantly, the requirement for operators to record technical infeasibility with respect to each of the four alternatives provided in the rule provides no benefit since these are not true, viable alternatives. The only scenario that should require documentation of infeasibility is the routing of recovered gas to a flow line.

Therefore, API requests EPA to modify the final rule language as follows:

§60.5375a to read:

> *(2) [Reserved]*
>
> *(3) If it is technically infeasible to route salable quality gas to a flow line or collection system, then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.*

§60.5420a (c)(1)(iii)(A) to read:

> *(A) For each well affected facility required to comply with the requirements of §60.5375a(a), you must record: The location of the well; the United States Well Number; the date and time of the*

onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under §60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (i.e., routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas ~~to~~ from the separator into a gas flow line or collection system, ~~as specified in §60.5375a(a)(1)(ii),~~ you must record the reasons for the claim of technical infeasibility. ~~with respect to all four options provided in that subparagraph, including but not limited to; name and location of the nearest gathering line and technical considerations preventing routing to this line; capture, reinjection, and reuse technologies considered and aspects of gas or equipment preventing use of recovered gas as a fuel onsite; and technical considerations preventing use of recovered gas for other useful purpose that that a purchased fuel or raw material would serve.~~

5. Flares for control of Subpart OOOO affected facilities Should Not be Subject to 40 CFR § 60.18 retroactively.

In its Final Rulemaking of both NSPS Subparts OOOO and OOOOa, EPA removed the exemption from compliance with 40 CFR § 60.18 for flares in Table 3 General Provisions. By this action, it could be interpreted that EPA has perhaps inadvertently and certainly improperly imposed a retroactive application of the standards for the design and operation of flares under 40 CFR § 60.18 used to control Subpart OOOO affected facilities, including those associated with maximum velocity restrictions. As indicated by the preambles to both the proposed and final rulemakings, EPA did not consider the potential retroactive effect of this change as it pertains to flares used to control all Subpart OOOO affected facilities, specifically including, but not limited to, flares used to control vapors from process unit affected facilities at onshore natural gas processing plants subject to NSPS Subpart OOOO. In addition, EPA confounds the issue further by its suggestion that the removal of the prior exemption under Subpart OOOO stands only as a clarification of its intent in response to petitions for reconsideration received under that rule.[2] Regardless of EPA's claimed basis for the removal of the exemption and if the changes are interpreted to apply retroactively, EPA's final rulemaking fails to adequately consider the impact the change has on operators who have designed and installed high velocity flares (e.g. sonic) based on the prior exemption in Table 3 at onshore natural gas processing plants to control Subpart OOOO process unit affected facilities between August 24, 2011 and September 18, 2015.

EPA suggests that changes to Subpart OOOO do not constitute a retroactive change of standards and references section VI.H of the preamble for more information regarding this issue.[3] In the proposed rulemaking, EPA acknowledged it was aware of flares used to control Subpart OOOO affected facilities

[2] See Chapter 14 of EPA's Response to Comments - Amendments to Subpart OOOO at page 14-3.
[3] Id.

that are not able to meet the maximum velocity requirements under 40 CFR 60.18 during periods of startup, shutdown, emergency and/or maintenance activities.[4] However, in section VI.H.5 of the preamble to the final rule, EPA dismisses the effect of the rule on flares at gas processing plants which cannot meet the subject velocity requirements during startup, shutdown, emergency or maintenance, and focuses only on flares used to control storage vessels, pneumatic pump, centrifugal or reciprocating compressors, which EPA suggests are able to be routed by closed vent system to low pressure flares.[5] EPA's dismissal on this point doesn't address the use of existing flares subject to NSPS Subpart OOOO by virtue of the flares' usage at gas processing plants to control both maintenance/upset emissions from relief valves and fugitive emissions from these same relief valves that are subject to leak detection and repair (LDAR) regulations under Subpart OOOO. These relief valves cannot be routed to a low pressure flare as these valves operate with either low/no flow (fugitive emissions control) or extremely high flow (maintenance/upset emissions control). During the high flow events, data suggests the flares used to control Subpart OOOO process units at onshore natural gas processing plants can potentially exceed the maximum velocity restrictions of 40 CFR § 60.18 (b) and (c).

An interpretation of retroactive application of 40 CFR § 60.18 in Subpart OOOO for high velocity flares constructed between August 24, 2011 and September 18, 2015 to control process unit equipment leaks and pressure relief events while exempt from §60.18 as specifically listed in Table 3, would create an immediate compliance burden that will result in significant costs to replace these flares. There is no other compliance alternative available. For this reason, API respectfully requests the EPA reconsider the retroactive application of 40 CFR § 60.18 for flares in Table 3 and retain the exemption in Subpart OOOO.

[4] 80 FR 56593, 56646 .
[5] 81 FR 35824, 35866-35867.

II. ADDITIONAL ISSUES

1. Clarification is required for boilers and process heaters used to reduce emissions, particularly as used for pneumatic pumps.

A. There must be a clear definition of control device and recognition that boilers and process heaters are not control devices that are subject to control design requirements in Subpart OOOOa.

Under Subpart OOOOa, the provisions related to "control device" and "routed to a process" or "route to a process" are inconsistent, confusing, and in some instances, conflicting. This is particularly the case with regard to boilers and process heaters in the context of controlling pneumatic pumps. Sections 13 and 24 of our December 4, 2015 comments discussed these issues in detail.

In Chapter 5 of its Response to Comments, EPA's explanation for not making API's requested changes relies primarily on its requirement that control of pumps does not need to meet the 95% control efficiency (§60.5393a(b)(4)) and that allowances have been made for technical infeasibility. However, at greenfield sites, EPA disallows technical infeasibility in the final rule and mandates 95% control efficiency (§60.5393a(b)(1)), making the agency's rationale only partially correct in its discussion of control efficiency and technical infeasibility allowances (see issue Item 2 of this letter for greenfield/brownfield sites). At brownfield sites, EPA requires reporting of design control efficiency if less than 95% (§60.5420a(b)(8)(i)(C)).

Inferring from the final rule, EPA appears to distinguish the issue of whether a boiler/heater is a control or process device by where the vent stream to be combusted is placed. §60.5413a(a)(3) exempts a boiler/heater from testing requirements if the vent stream is tied into the primary fuel or is the primary fuel for the heater firebox. This exemption indicates that EPA treats boilers/heaters as a process device. Conversely, if the vent stream is directed at the flame zone, then the boiler/heater appears to be considered a control device under the rule per §60.5412a(a)(1)(iv).

Boilers and process heaters are not designed as control devices regardless of where the vent stream is placed and are not purchased and put into service based on any inherent control efficiency design. Consequently, boilers and process heaters, at least with respect to pneumatic pumps, should only be considered as process devices, which is inherent of their operational use. If EPA intends to have these devices considered for reducing emissions from diaphragm pneumatic pumps, there should be no associated control efficiency listed in §60.5393a(b), and there should be no efficiency design requirement in §60.5420a(b)(8).

B. The control efficiency determination for boilers and heaters is not practically feasible and the requirement should be removed.

Control efficiency for pneumatic pumps is a rather meaningless number because of the variable operating conditions associated with pumps and boilers/heaters.

Pumps and boilers/heaters can be operated seasonally or on an episodic, seasonal, or otherwise intermittent basis which may not compliment the need to continually combust an affected source's emissions. A boiler or process heater may be offline at the time pump discharge is sent to the heater or boiler for combustion. In other words, it can be "hit or miss" with respect to any single pump discharge being combusted. If a boiler or heater operates only seasonally but a pump is used year round, long periods of time will occur where combustion of the pump discharge will not occur. The intermittent nature of some well site process heaters and boilers makes designed control efficiency a meaningless data point since there could be frequent periods where emission reduction of pump discharge does not occur.

Failing a definition of control device under Subpart OOOOa that eliminates the treatment of boilers and process heaters as controls, at least with respect to control of pneumatic pumps emissions, EPA should at least clarify that operators are only required to specify the level of emission reduction expected when a given control device, heater, or boiler, is in normal operation.

C. Technical infeasibility determination for boilers and heaters should be simplified.

While the technical infeasibility issue is addressed in more detail in Item I.2 with respect to greenfield and brownfield sites, EPA should explicitly list in the rule those common situations that would meet the technical infeasibility determination.

If any of these situations were to occur at a site with an affected pneumatic pump, no certifications should be required to document why pump emissions are not being controlled by a device present onsite:

- Presence of boilers and process heaters not regularly operated (e.g. seasonally used equipment).
- Flare, heater, or boiler has a rated heat capacity that would be exceeded if the discharge of pump were to be sent to it.
- Presence of only a high pressure flare(s).
- Retro-fit to existing equipment may require manufacturer certification, nameplate update and/or void equipment / emissions warranty for purchased or rental equipment.
- Minimal space allotted for emission gas routing and heater/boiler system integration.

If the requirement to certify technical infeasibility remains, then, for the above situations, which will be some of the most common, operators should only be required to document and not certify the cause of the infeasibility. This approach would also be consistent with API's comments above that PE certifications should be removed from the rule and stayed pending reconsideration. As discussed in Item I.1, API believes the PE certification adds burden while not adding emission reductions and, as is the case with all required PE certifications in the rule, this requirement was not proposed originally and thus we were not provided proper notice and comment ability.

2. The compliance assurance requirements for a closed vent system (CVS) routing emissions from a pneumatic pump to a control device should be aligned to the requirements for storage vessels and not centrifugal and reciprocating compressors as currently finalized.

As noted in our December 4, 2015 comment letter on the proposed Subpart OOOOa, the compliance provisions related to the capturing of emissions from pneumatic pumps should be consistent with the requirements associated with closed vent systems for storage vessels and not those for wet seal centrifugal compressors and reciprocating compressors. Pneumatic pumps are most often located at well sites and small compressor stations that are more likely to have control devices installed to control emissions from storage vessels.

However, as finalized, the rule currently requires the same monitoring as required of affected centrifugal and reciprocating compressors – i.e. annual method 21 in addition to OGI monitoring for determination of fugitive leaks for closed vent systems for pneumatic pumps. These requirements are inappropriate, unduly burdensome, and duplicative. The costs for this requirement were not included in the cost analysis, and the negligible amount of emissions from pneumatic pumps does not justify this additional expense. The olfactory, visual, and auditory (OVA) inspection requirements associated with storage vessel closed vent systems are more appropriate.

The requirements for inspection and monitoring of closed vent systems associated with pneumatic pump affected sources should be moved from §60.5416a(a) & (b) (centrifugal and reciprocating compressors)[6] to §60.5416a(c) to be consistent with the requirements for affected storage vessels. Alternatively, EPA could simplify all closed vent system inspection and monitoring requirements to have all systems subject to the provisions of §60.5416a(c).

3. There should be a pathway to reduce LDAR survey frequency to annual for well sites and semi-annual for compressor stations.

In comments on the proposed Subpart OOOOa, API explained why a fixed annual frequency would be the appropriate frequency for well sites and compressor stations. Cost effectiveness determinations did not correctly capture costs and subsequent benefits. The model plant used for the cost effectiveness determination did not adequately reflect that most well sites are much smaller than the model plant used in the EPA's analysis, which results in misrepresentation of smaller sites in the cost effectiveness determination. New industry data collected by an API member company (See Attachment A), shows that leak rates can remain well below the target leak threshold of 1% that was proposed with a fixed annual survey program.

EPA should update the model plant basis to be more reflective of actual well sites and revise cost effectiveness since the original analysis was based on unrealistic prices and emission reduction potentials. EPA should also consider evaluating the monitoring data becoming available from various new state programs to better inform the basis of assumptions throughout the analysis. (See section 27.3 of API's December 4, 2015 comments.) At a minimum, EPA should only initially require semi-annual or quarterly surveys for 2 years and then allow annual surveys for sites that do not have leaking a significant number of leaking components.

[6] Note also that there is no reference in §60.5393a for the CVS provisions required in §60.5416a(a); only §60.5416a(b) is listed. This leaves confusion as to EPA's intent regarding whether §60.5416a(a) would apply to a CVS routing emissions from a pneumatic pump.

API recommends providing an optional threshold of six (6) leaking components to allow monitoring frequency to be reduced since six leaking components represents 1% of components in EPA's model plant for gas well sites. Note that with a six leaking component threshold, survey frequency is more stringent for sites equal to or larger than the model plant and less stringent for the smaller sites, which were not properly represented on the cost effectiveness determination.

4. There should be an exemption from LDAR requirements for new low production wells and a pathway to discontinue LDAR at new wells that become low production wells.

In the preamble of the rule proposal, EPA solicited comment on the air emissions associated with low production wells, and the relationship between production and fugitive emissions. Specifically, EPA was interested in the relationship between production and fugitive emissions over time. EPA also solicited comment on the appropriateness of this threshold for applying the standards for fugitive emissions at well sites, in addition to whether EPA should include low production well sites for fugitive emissions and if these types of well sites are not excluded, should they have a less frequent monitoring requirement.

While the amount of production through a particular facility does not directly impact the amount of fugitive emissions, the number of fugitive components at that facility can increase if additional equipment is added to handle an increase in production (for instance a new well brought online with an additional train of process equipment), and can decrease substantially as production declines if production equipment is either disconnected or removed from the site so that it may be utilized elsewhere or sold. Typically, stripper wells have decreased in production to the point where there may be minimum equipment on site compared to average higher production wells for which EPA's model plant was based. (Note: the average oil stripper well in the U.S. averages approximately 2 BOPD, even though one threshold for classification as a stripper well is 15 BOEP).

As indicated in Section 27.2.4 of our December 4, 2015 comments, sites with equipment configurations or component counts significantly less than EPA's model plants should be exempt from the LDAR requirements based on cost effectiveness. EPA is not correct in their Response to Comments (EPA-HQ-OAR-2010-0505-6983, Excerpt 17) that suggests the model plant cost analysis should equate to all well sites, even those with significantly fewer components, since there are larger well sites that have more components. The best system of emission reduction (BSER) is not based on a calculated average value, but rather it establishes a threshold limit where controlling a source above the threshold is considered cost effective and controlling a source below the threshold is not. One example of this is found in 40 CFR Part 60, subpart JJJJ where applicability and levels of control are linked directly to rated horsepower, which is generally proportional to potential emissions. There is a threshold (e.g. rated horsepower) where technology limits are cost effective and below which they are not. As communicated to the Agency previously, API continues to recommend EPA apply a similar approach for low production wells in regards to LDAR because the typical count of components at those facilities is substantially less than the EPA's model plant analysis.

In addition, low production sites typically have lower operating pressures than average high production sites. Most low production sites operate with a gas gathering system operating at relatively low pressures (<50 psig) because the depleted well cannot provide enough pressure to get into a typical gas gathering pressure of 125 to 200 psig. The number of fugitive components and operating pressure are the two variables that determine leak rates from fugitive components. While production rate does not directly affect the amount of fugitive emissions from a site, it is an appropriate surrogate in the case of low production wells because higher production sites typically have enough wellhead pressure to operate at the higher pressures needed to get into a 125 to 200 psig gas gathering system.

EPA should revise the rule to provide an exemption for low production wells [15 BOED (stripper well)] as requested in API's prior comments. API suggests low production wells be considered wells with < 15 barrels oil equivalent production per day (BOED), also known as stripper wells. Additionally, EPA should provide a mechanism to cease LDAR surveys when production from well sites drops below 15 BOED. The cessation of LDAR after production drops is analogous to the ability the rule provides to remove a control device after emissions from a storage vessel drop.

5. Oil wells should be exempt from the LDAR requirements.

Based on EPA's estimates from the rule proposal, LDAR requirements for oil well sites were not cost effective. Accordingly, API commented that oil wells should be exempt from the Subpart OOOOa LDAR requirements in Section 27.2.8 of our December 4, 2015 comments.

While finalizing the rule, EPA revised the model plant assumptions for oil well sites significantly. This is described in Section 4.2.2.3 of the Final Technical Support Document (TSD). As described in the TSD, EPA created two oil well site model plants, one representing oil well sites with < 300 GOR and one for sites with greater than 300 GOR. The less than 300 GOR oil well site model plant is essentially the same as the model plant proposed. However, for the greater than 300 GOR oil well site model plant, EPA arbitrarily added components to the site. EPA stated:

> "*To develop the model plant for oil well sites with a gas-to-oil ratio greater than 300 standard cubic feet of gas per stock barrel of oil (greater than 300 GOR), three meters/piping were added to the equipment counts included for the less than 300 GOR model plant to account for the handling of the natural gas from the well.*"

There are several problems with the approach EPA took in updating the model plant.

- EPA made significant changes to fundamental assumptions regarding the component counts. These changes resulted in large changes to the cost effectiveness values as the emissions per site more than doubled due to the change.
- EPA is assuming that an oil well model plant with greater than 300 GOR would look exactly like a gas well in terms of the numbers of components associated with metering and piping. In fact, the gas well site assumptions were used directly for the greater than 300 GOR oil well sites.
- EPA is treating "meters/piping" as if it is a single piece of equipment and scaling the number of "meters/piping" based on the assumed number of wells present. In reality, there are many cases where no gas metering occurs at a well site. Further, it is even more infrequent for there to be a need to add proportionally more piping or meters as more wells are brought on line at a given site. The sharing of equipment is a key benefit of multi-well sites.

EPA's updated analysis, indicates, that for oil wells greater than 300 GOR, the costs per ton of methane and per ton of VOC were 2 times higher than for gas wells. Further, for oil wells less than 300 GOR costs per ton were 4 ½ times higher than for gas wells. Therefore, at a minimum, EPA should exempt oil well sites less than 300 GOR from the leak detection and repair requirements, as control of these facilities is still not cost-effective.

6. The timing of LDAR Surveys should be updated to allow for integration into existing LDAR programs.

The final rule states that an initial survey must be completed within 60 days of start of production for a well site or within 60 days from startup or modification of a compressor station. Subsequent surveys then are to take place on a semiannual basis for wells sites and a quarterly basis for compressor stations. The implementation of LDAR programs is not trivial; there are numerous challenges to building a robust program. While API appreciates EPA's recognition of this by providing for a one-year phase in for the LDAR requirements, there remain challenges with the required timing of initial inspections. Given the significant distances between many oil and gas sites, the requirement to have an initial inspection within 60 days creates significant burden for very little benefit when the initial inspection could easily be rolled into the next periodic inspection for the other sources in that area. Furthermore, many sites are located in extremely cold climates in the intermountain west or Alaska that may not be reachable to do the LDAR surveys within 60 days (see also item immediately below).

API recommends EPA allow 180 days for the initial survey. It is noted that this timing is not expected to result in significantly more emissions. If a 180 day period were allowed, on average, half the sites would likely be surveyed at less than 90 days and half would likely be surveyed between 90 to 180 days.

7. The LDAR requirements must include adequate provisions to account for extreme weather in cold climates.

The temperatures on the Alaskan North Slope, and certain other areas throughout the country, are bitterly cold during winter months and adequate provisions must be considered in applying the LDAR provisions in the Subpart OOOOa.

A. The operations on the Alaskan North Slope should be categorically exempt from the LDAR requirements.

EPA set this precedent within Subpart OOOO and now Subpart OOOOa by allowing for an exemption from LDAR in §60.5401(e) and §60.5401a(e) for natural gas processing plants located on the Alaskan North slope. EPA should consider similar exemptions from LDAR for well sites and compressor stations since these operations experience the same harsh conditions.[7]

In the final Subpart OOOOa, the minimum requirement between the semi-annual surveys is 4 months for well sites. The semi-annual surveys on the Alaskan North slope could only be conducted in May/June and September/October due to sustained low winter time temperatures (approximately five consecutive months with average temperature below 0 degrees Fahrenheit). While EPA acknowledged that an exemption was needed for compressor stations and provided a waiver for quarters where the ambient temperatures are below 0 degrees Fahrenheit, the same was not done for well sites. EPA described the rational for this by assuming there would be no 6-month period where all months were below 0 degrees Fahrenheit average. The rule requires an OGI on newly affected sites within 60 days of completion, which is not practical on the Alaskan North Slope five months of the year. For example, if a well is completed at the end of November, an OGI would be required by the end of January. This would not be possible as the ambient temperatures in mid-November through mid-April are very rarely above 0 degrees Fahrenheit on the Alaskan North Slope. Moreover, the 30-day repair window does not accommodate the reality on the Alaska North Slope that parts (custom parts designed for Arctic environment) may be unavailable, and there is no delay of repair provision for this issue.

EPA should consider an exemption for operations on the Alaskan North Slope. At a minimum, EPA should allow for a waiver at well sites similar to the provisions provided for in §60.5397a(g)(5) for compressor stations and extend the initial survey frequency to 8 months (240 days) to adequately account for weather conditions in this region. Extension of the initial survey timing would allow for the survey to coincide with semi-annual survey frequencies. In addition, it would be appropriate to include as a reason for delay of repair, parts unavailability for the Alaska North Slope.

B. Inclement Weather Considerations for completing LDAR are necessary.

For other parts of the country in the Lower 48 that experience sustained inclement weather (Wyoming, North Dakota, Colorado, etc.), EPA should provide an additional extension of time to complete the initial and subsequent surveys due to possible road closures, accessibility of the site and safety of personnel. For example, it is common in states like Wyoming and North Dakota for a snow storm to cover the ground in multiple feet of snow, which would prevent access to many remote well site and compressor station locations. Extended periods of high winds are also common and similarly impact ability to complete surveys.

At a minimum, a 30 day extension should be granted to adequately handle unforeseen inclement weather events.

8. There should be a simple process for determining State Equivalency for the LDAR requirements at the State level; not just the process outlined in §60.5398a for Alternative Means of Emissions Limitations.

The Alternative Means of Emission Limitation (AMEL) process described in §60.5398a and §60.5402a are conceptually helpful, but the process appears to be limited in terms of true practical benefit. EPA's intent is not explicitly clear. For example, once an AMEL has been approved, can it be used by anyone operating in that particular state? While this should be the case, it is not clear. It is inefficient to have multiple operators petitioning for the same equivalency if all operators in a state are subject to the same state requirements. The inefficiency of individual operator petitions will lead to extensive delays of petition approval. EPA's language in the Subpart OOOOa seems to indicate that only owners/operators can apply; however, the potential for various trade groups to petition on behalf of its members in a state would avoid duplicative work by individual operators and burden on EPA. Additionally, under the proposed approach, it is not clear exactly what happens if the state subsequently revises its LDAR requirements. Would the AMEL become invalid? Would there be a grace period to request an update to the equivalency determination?

EPA should consider additional AMEL processes or provide guidance to reduce burden on operators and EPA. For example, EPA should consider allowing trade associations to petition on behalf of operators. At a minimum, EPA must clarify that upon approval of any request for a particular state, all operators in that state can immediately rely upon that equivalency determination.

9. The definition of modification for LDAR should only include wells that are hydraulically refractured in combination with the installation of new production equipment on site.

As mentioned in our December 4, 2015 comments regarding exemption of low production wells from LDAR, the amount of production, in and of itself, does not increase or decrease the amount of fugitive emissions emitted from a site with the relative same number of fugitive components and same approximate operating pressure. A well that is refractured typically does not require additional production equipment and does not typically operate at a pressure higher than before the refracturing since that pressure is set by the gas gathering system pressure. Therefore, as long as a significant piece of processing equipment is not constructed along with the refracture, there is no emissions increase and there is no "modification" as defined in CFR Part 60.2

API recommends that EPA make the following revisions:

- Revise the last sentence in §60.5365a(a): … *However, hydraulic refracturing of a well, <u>with the construction of additional permanent process equipment (storage vessel, separator, compressor, heater treater, or meter-run)</u>, constitutes a modification of the well site for purposes of paragraph (i)(3)(iii) of this section, regardless of affected facility status of the well itself.*
- Revise §60.5365a(i)(3)(iii): *A well at an existing well site is hydraulically refractured <u>and additional permanent process equipment is constructed (storage vessel, separator, compressor, heater treater, or meter-run)</u>.*

10. The digital photo/video requirements associated with LDAR provision in §60.5420a should be removed.

As documented in EPA's Response to Public Comment document (see EPA-HQ-OAR-2010-0505-6924), EPA responded to a request from the State of Arkansas seeking removal of the requirement to keep photograph records by stating: *"The date-stamped digital photograph serves as a record that someone performed a monitoring survey at the site. In the traditional LDAR scenario, the owner or operator tags all of the equipment that must be monitored, and when the Method 21 operator subsequently inspects the affected facility, the operator scans each component's tag and notes the component's instrument reading. This log serves as a documentation of the LDAR monitoring survey. In the fugitive emissions program under subpart OOOOa, we are not requiring owners and operators to document readings for each component, but we still need a compliance assurance mechanism to document that a monitoring survey was performed. We believe that keeping a digital photograph from the survey is a quick and easy way to fulfill this requirement."*

There are two major issues with EPA's logic in requiring these records. First, a digital photo technically only proves that someone was present on site and not the completion of an emission survey. Second, EPA continues to equate the sources covered under OOOOa with sources covered by "traditional LDAR". Chemical plants and refineries with traditional LDAR programs have full-time dedicated staff on site to manage the significant demands associated with running a "traditional LDAR" program. This is very different from un-manned remote production facilities.

API believes that records of repair and tagging of leaks in addition to general recordkeeping validates completion of surveys. EPA should remove the digital photo/video requirement for each OGI survey. At a minimum, EPA should modify the rule to make the photo requirement optional similar to that for REC recordkeeping, where the use of photographs is an alternative to other recordkeeping requirements.

11. Monitoring plan observation path and sitemap requirements under §60.5397a(d) are excessive and should be removed.

A company monitoring plan will cover all the relevant material needed for an effective LDAR program. While EPA eliminated the need for site-specific plans, the requirements for inclusion of site-specific information within the plan remain. There is no added benefit and there is significant added cost of developing hundreds and up to thousands of site-specific details to be included in monitoring plans.

The proposed requirement for site-specific monitoring plans, including the requirement to specify an observation path for each site, is unnecessary and the requirements are onerous. Many times, production areas do not have site maps developed for each site. Development of a sitemap would be solely for this rule. The cost of developing site maps for every site was not included in the cost evaluation for LDAR. Furthermore, the requirement to specify an observation path for each site is unnecessary for oil and natural gas well sites and compressor stations. The person conducting the survey must be trained and have the knowledge and ability to use the monitoring device.

Therefore, EPA should remove the requirements listed under §60.5397a(d)(1) and (2).

12. Delay of Repair Provisions require additional clarity.

In the Preamble of the final rule (FR 35858), EPA states:

> *We also agree that a complete well shutdown or a well shut-in may be necessary to repair certain components, such as components on the wellhead, and this could result in greater emissions than what would be emitted by the leaking component. The EPA does not agree that unavailability of supplies or custom parts is a justification for delaying repair (i.e., beyond the 30 days for repair provided in this final rule) since the operator can plan for accessible or obtaining the parts within 30 days after finding the fugitive emissions.*
>
> *Based on available information, it may be two years before a well is shut-in or shutdown. Therefore, to avoid the excess emissions (and cost) of prematurely forcing a shutdown, we are amending the rule to allow 2 years to fix a leak where it is determined to be technically infeasible*

> *to repair within 30 days; however, if an unscheduled or emergency vent blowdown, compressor station shutdown, well shutdown, or well shut-in occurs during the delay of repair period, the fugitive emissions components would need to be fixed at that time. The owner or operator will have to record the number and types of components that are placed on delay of repair and record an explanation for each delay of repair.*

§60.5397a(h)(2) states:

> *If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier.*

This language was not in the proposed rule. The proposed rule for delay of repair was as follows:

> *If the repair or replacement is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier. (from page FR 56611)*

While API appreciates EPA's recognition that it was not appropriate to require a shutdown after a maximum of six (6) months as EPA originally proposed, the language finalized in Subpart OOOOa requires more clarity. Additional clarity is needed because the language in §60.5397a(h)(2) presumes that various shut down events and well shut-ins would necessarily result in the blow down of all equipment located on site (including the leaking component on delay of repair). This is not accurate. For example, during a well shut-in, some equipment on site may remain isolated, but under pressure (such as the line pressure leaving a well pad).

Further, there are commonly occurring, brief events that could be interpreted as well shutdowns or shut-ins, but should not be. These include: short interruptions in production to control reservoir pressure and manage well life such as plunger lift, pump rod, and manual intermittent well flow control. In addition to these events being very short, some are automated. The events are driven by the need to react to field conditions and, in most cases, they are not possible to predict and plan repairs of leaking components around.

While EPA recognizes that wellhead components may need leak repair, a leak in the master valve or connections below the master valve or at the bradenhead is a special situation that EPA needs to consider. Above the master valve of the Christmas tree, a leak can be repaired provided the master valve or other valve below or behind the leak doesn't leak when closed. Christmas trees are configured differently depending on the expected pressure and flow of the well, and high pressure trees may have dual master shut-in valves while low pressure trees may have only one. However, the lowest master valve is the isolation valve of last resort. If it is the source of the leak or the valve will not close properly to allow shut in of the well if needed to isolate it from the wellhead leak, or the bradenhead connection below the master valve is the source of the leak, a workover will most likely be needed to set a plug downhole to isolate the well so that a wellhead leak can be repaired. If the leak needing repair is small and not a safety concern, then mandating a leak repair within 2 years would not seem appropriate as a needed workover is a significant cost in addition to the cost of repairing or replacing the leaking component. For this situation, a delay of repair for a wellhead should be conditionally based on when a workover is needed for other downhole work and should not be subject to a 2 year limitation. A workover may be less than 2 years in some cases, but it can also be more.

In some cases, such as on the Alaska North Slope, the shutdown of a facility or a group of facilities in the winter can pose significant risks, including potentially the lack of primary electricity generation and space heating, and the potential for idle flow lines to gel or freeze. Backup diesel power generation is available only in limited capacities, and has higher emissions than gas turbines. In such extreme cases, bringing critical facilities back on line should not be delayed for relatively minor repairs for fugitive methane emissions. The rule should allow for such overriding considerations and not put the operator in a position of having to elect between regulatory compliance and prudent facility operations.

API proposes revising the language found at §60.5397a(h)(2) to read:

> *If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown ~~or well shut-in~~, or would be unsafe to repair during operation of the unit, the following special provisions apply. For wellhead component repair or replacement that requires a workover for downhole work to isolate the well from the wellhead leak, repair must be made not later than the next scheduled workover to repair or re-condition the well. Otherwise, the repair or replacement must be completed during the next event requiring a blowdown of the equipment on which the leak was detected, with the shutdown lasting more than one day (e.g. compressor station shutdown, well shutdown, ~~well shut-in,~~ or after a ~~n unscheduled,~~ planned ~~or emergency vent~~ blowdown) or within 2 years, whichever is earlier.*

13. Issues with Compliance Demonstration Requirements for Combustion Devices and Flares Not Addressed.

EPA has failed to adequately respond to and understand concerns that API raised in our December 4, 2015 comments on the control device testing and monitoring compliance assurance related to measuring the volumetric flow rate as required under §60.5413a(b)(2) and under §60.18(f)(4) from storage vessels. Using Method 2, 2A, 2C, or 2D is not technically feasible[8].

EPA's response to comment, copied in below, did not fully address API's comments, nor did EPA cite aa specific meter a specific scenario where EPA has performed testing using Method 2, 2A, 2C, or 2D at a well pad. Specifically, EPA has not adequately shown resolution of the technical challenge of directly measuring the volume of material resulting from the flash of materials in storage vessels that occurs only when the separator dumps condensate to the storage vessel.

The impact to environmental emissions controls is that flow to the control device varies from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized larger than ideal steady state conditions would dictate and makes flow measurement infeasible, particularly to meet the requirement to accurately measure such volume

[8] See Comments 12.1, 12.3, and 12.5 of API's December 4, 2015 comments on Subparts OOOO and OOOOa.

within ±2 percent. Industry has found no such flow meter available that can handle the variable flow which occurs with many of our combustion devices.

EPA has not provided industry with information of such a meter either. A turbine meter with a flow totalizer can be used, however if the upper or lower ranges are exceeded during the 1-hour test, the accuracy of the totalizer may be compromised. For a pitot tube, only a finite number of traverse sets can be collected during a 1-hour period, and can only be used if there is a constant flow, which is not the case with tank flash.

Aside from the technical challenges of obtaining an accurate flow reading for a performance test, there are safety risks for testing personnel due to the need to access the flow line feeding the control device while equipment is operation and flow to device is occurring. To adequately mitigate these risks, a facility shutdown, potentially including the shut-in of numerous wells would need to occur. It is not believed this was EPA's intent as these costs were not considered in rule development. Otherwise, a permanent flow meter would have to be installed, which EPA also did not include in the cost of the control device.

The following excerpt is from EPA's discussion of this in Response to Public Comments Document (Chapter 11):

> *Response: Concerning the portion of the comment related to auto-ignition devices, see response to DCN EPA-HQ-OAR-2010-0505-6808, Excerpt 17. Concerning the portion of the comment related to sonic flares, see response to DCN EPA-HQ-OAR-2010-0505-6846, Excerpt 1.*
>
> *The EPA agrees with the commenter on the ambiguity in regards to the requirements for flares used to control storage vessel emissions. We have revised the final rule to make our intent clear that flares are an acceptable control options under §60.5412(d) and §60.5412a(d) and to add applicable performance requirements for these flares.*
>
> *We are not providing an exemption for low-pressure flares to operate outside of the requirements of §60.18 during malfunction events. The restrictions in §60.18 ensure that the flare will achieve the desired destruction efficiency. The standard for destruction efficiency applies at all times, even during startup, shutdown, and malfunction. Allowing an exemption during these times provides no compliance assurance that the standard is achieved.*
>
> *We disagree that a performance test for flares is unnecessary or burdensome. The performance test ensures that the flare maintains a high destruction efficiency. Determining volumetric flowrate is a simple demonstration. While we acknowledge that engineering calculations can be a valuable tool for demonstrating compliance, actual measurements are necessary to demonstrate the accuracy of the engineering calculations. Actual measurements are also a useful tool for correlating and adjusting engineering calculations.*
>
> *We do not believe that there is a technical infeasibility issue in measuring the gas flow to the flare. While we believe that there will be a high enough flow to the flares to easily measure the flow as the performance test should only be performed at representative conditions, we note that the EPA flow methods are capable of handling low, intermittent and non-steady flow conditions.*

> *Finally, we note that the commenter previously stated that the EPA was incentivizing flare use by requiring measurement of gas flow on enclosed combustion devices, even though an enclosed combustor "yields higher destruction efficiencies than flares". The commenter further stated, "It is counterproductive for the environment to disadvantage enclosed combustors". While the EPA is not requiring a particular control device in Subpart OOOOa, in light of the commenters previous statement about not disadvantaging enclosed combustors, we do not believe that it is prudent to remove compliance demonstrations from flares when enclosed combustors are subject to such a requirement. All control devices should perform a demonstration that they are capable of achieving what they are required to achieve.*

Also, EPA has failed to justify why compliance for a MACT standard (NESHAP HH) is cost effective and necessary under an NSPS for small, dispersed, unmanned facilities in response to Comment 12.2.

The compliance demonstration requirements are still on a mass basis versus a volume basis which the standards are set at as API noted previously[9].

EPA had proposed revisions to the outlet concentration compliance method of §60.5412a(d)(1)(iv)(B) raising the TOC (minus methane and ethane) level from 20 ppmv to 600 ppmv; however, in the final rule this value was changed to 275 ppmv without the opportunity to comment.

API requests that EPA review this issue further and revise the performance testing criteria accordingly. At a minimum, API requests that EPA provide language in the rule to allow for the option to petition for an alternative compliance demonstration for flares and non-certified enclosed combustors.

14. Requiring use of the Compliance and Emissions Data Reporting Interface (CEDRI) if EPA releases the electronic reporting form 90 days prior to the report due date is insufficient for compliance.

As mentioned in our December 4, 2015 comments, it is inappropriate for EPA to require electronic reporting under the Subpart OOOOa before the system is demonstrated capable of accommodating the unique nature of the oil and natural gas industry. The electronic reporting system is not proven generally at this time. Further, the system will require configuration to allow the current area based reporting versus facility by facility. In the past, system revisions have resulted in significant IT challenges, and appropriate time needs to be allowed for the agency to develop, QA/QC, user test and train reporters on the new system. Operators need a significant amount of time to update internal systems to efficiently use CEDRI.

A poorly designed form without adequate testing is likely to result in additional burden to industry with no environmental benefit. Without a final CEDRI rule, more time may be needed to resolve issues in the final rule through the petition process. Finally, EPA cannot require industry to regularly monitor the EPA website for the availability of the CEDRI functionality required in the Subpart OOOOa.

EPA should amend the final rule language to formally allow for continuation of the initial reporting approaches from Subpart OOOO for three years to allow for rollout of the electronic reporting system. In addition, EPA should have a beta test period for CEDRI form before finalizing the form for industry

[9] Comment 12.4 of API's December 4, 2015 comments on Subparts OOOO and OOOOa.

use. At a minimum, EPA should amend the rule language to require CEDRI reporting only if the form is available for a minimum of 1 year prior to required reporting, not the 90 days as required in the current rule.

15. The definition of Capital Expenditure should be removed in §60.5430 of Subpart OOOO as it could be interpreted to imply retroactivity and the OOOOa procedure for calculating capital expenditure should be revised.

In its final rulemaking, EPA added a definition for "capital expenditure" to both Subpart OOOO and Subpart OOOOa claiming to "update[ ] the formula to reflect the calendar year that subpart OOOO was proposed, as well as specified that the B value for subpart OOOO is 4.5"[10]. The rule could be interpreted to impermissibly and retroactively alter the definition under Subpart OOOO. Under such an interpretation, EPA's revision to the Subpart OOOO definition, while cloaked as an update, would apply a legally impermissible retroactive calculation of "capital expenditures". EPA has not demonstrated that the CAA authorizes EPA to retroactively promulgate capital expenditure rules for evaluating modifications. See Bowen v. Georgetown University Hosp., 488 U.S. 204, 471 -72. (1988) ("Retroactivity is not favored in the law." "The power to require readjustments for the past is drastic."). Before EPA can make retroactive changes to Subpart OOOO, it must establish that the CAA allows for retroactive rulemaking. Id. ("it is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress."). EPA has not done this. Moreover, EPA states that "our intent was not to recreate a retroactive requirement by revising subpart OOOO." [11]

Subpart OOOO previously did not separately define "capital expenditure" leaving the only applicable definitions as those included in 40 CFR § 60.2 and/or NSPS Subpart VV.[12] Prior to the rulemaking, (specifically from August 23, 2011 through September 18, 2015), if an operator of an onshore natural gas processing plant had a project at a process unit at the plant, which resulted in a physical or operational change that might be considered a modification, they had to rely upon the provisions associated with NSPS VV. A determination would have been made as to whether a facility change was a modification, i.e. resulted in a physical or operational change that caused an increase of emissions and required a capital expenditure. By changing the definition in Subpart OOOO, it could be interpreted that EPA appears to force operators to re-evaluate prior applicability determinations. Such a scenario would be unreasonable. In EPA's response to comments (section VI.H of preamble and Chapter 14 of Response to Public Comment document), this issue is lumped in with other reconsideration items and does not appear to have been considered adequately by itself.

Additionally, the formula provided by EPA in the definition for Capital Expenditure under Subpart OOOO does not work for a process unit constructed during 2011. For a project where capital expenditure was

[10] 81 FR 35867.
[11] 81 FR 35866.
[12] Previously, for all terms not otherwise specifically defined, Subpart OOOO incorporated by reference the definitions found in the Clean Air Act, in Subpart A and Subpart VVa of 40 CFR Part 60. Subpart VVa's definition of a "capital expenditure" was stayed effective June 2, 2008. See 73 FR 31376 (June 2, 2008); and 73 FR 31379 (June 2, 2008). Thus, as NSPS Subpart KKK cross referenced NSPS Subpart VV, in order to analyze whether a "capital expenditure" occurred for purposes of determining whether a project was exempt from being a modification under 40 CFR § 60.14, an operator employed the terms as defined under 40 CFR § 60.2 and Subpart VV.

being considered, the formula results in the need to take the log(0), which mathematically can only be represented by negative infinity.

EPA must remove the definition of Capital Expenditure from Subpart OOOO to resolve the potential enforcement interpretation of its retroactive applicability, and to comply with Supreme Court rulings on impermissible retroactive application. Bowen, 488 U.S. 204; *Greene v. United States,* 376 U.S. 149, 160, 84 S.Ct. 615, 621–622, 11 L.Ed.2d 576 (1964); *Claridge Apartments Co. v. Commissioner,* 323 U.S. 141, 164, 65 S.Ct. 172, 185, 89 L.Ed. 139 (1944); *Miller v. United States,* 294 U.S. 435, 439, 55 S.Ct. 440, 441–442, 79 L.Ed. 977 (1935); *United States v. Magnolia Petroleum Co.,* 276 U.S. 160, 162–163, 48 S.Ct. 236, 237, 72 L.Ed. 509 (1928).

Further, API believes that the definition of Capital Expenditure (and the equation listed in OOOOa) is unrepresentative of current economic conditions. It was meant to model inflation in the late 1970s and early 1980s, as stated in EPA-FR-1984-Vol 49 No 105, P 22603.

API requests that EPA utilize a ratio of Consumer Price Indices (CPI), as noted in our original comments and as used in the “Civil Monetary Penalty Inflation Adjustment Rule” published in the Federal Register on July 1, 2016 and located at **http://federalregister.gov/a/2016-15411**.

Moving forward, the definition under Subpart OOOOa with our recommended changes will ensure consideration of the definition as we think EPA intended for determination of applicability to modifications.

16. EPA should clarify that coil tubing cleanouts and screenouts are not subject to the provisions in §60.5430a.

API submitted a letter to EPA on June 13, 2016 seeking clarification regarding “screenouts” and “coil tubing cleanouts”. As EPA has previously acknowledged in its September 28, 2012 letter to API, there are necessary processes performed during hydraulic fracturing that are not associated with flowback following hydraulic fracturing and thus not subject to Subpart OOOO. With Subpart OOOOa, EPA must clarify that screenouts and coil tubing clean outs are not subject to the requirements in §60.5375a.

API is proposing to address this issue by adding clarification of the definition of “flowback” §60.5375a as noted below.

> *Flowback* means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage. Screenouts and coil tubing clean out activities on a well are not considered part of the flowback process.

17. Additional Technical Corrections

A. §60.5393a(b)(3)(ii)

In §60.5393a(b)(3)(ii)there is reference to a paragraph that does not exist. API believes EPA intended for this section to reference (b)(3)(i) instead as follows:

"If you subsequently install a control device or have the ability to route to a process, you are no longer required to comply with paragraph ~~(b)(2)(i)~~ (b)(3)(i) of this section..."

B. §60.5397a(d)(4)

"Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with paragraph (g)(3)(i) of this section, and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with paragraph ~~(g)(3)(ii)~~ (g)(4)(ii) of this section."

C. Pneumatic Pump Affected Facilities Outside a Natural Gas Processing Plant

As explained in the preamble (81 FR 35850), EPA has decided to finalize pneumatic pump requirements only for well sites, and not for the gathering and boosting, and transmission and storage segments. This decision was reflected in the final rule by limiting the scope of pneumatic pump affected facilities to pumps "located at a well site", which is a change from the language in the 9/18/2015 proposed rule about pumps "not located at a natural gas processing plant." However, the phrase "not located at a natural gas processing plant" still remains in several paragraphs in the final rule, including: §§60.5410a(e)(2), (3), (4), and (5). This phrase should be replaced with "at a well site."

D. Fugitive Emissions - Timeframe for Resurvey

In the introductory paragraph §60.5397a(h)(3), a resurvey following the repair or replacement of a component is required to be conducted as soon possible, but no later than 30 days "after being repaired." However, §60.5397a(h)(3)(i) requires the resurvey be conducted within 30 days "of finding such fugitive emissions." To be consistent with the introductory paragraph, §60.5397a(h)(3)(i) should be revised as follows:

§60.5397a(h)(3)(i)

For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using either Method 21 or optical gas imaging within 30 days after being repaired ~~of finding such fugitive emissions~~.

E. Table 3 Reference

Table 3 of Subpart OOOOa states that §60.8 applies with the explanation of "Performance testing is required for control devices used on storage vessels, centrifugal compressors and pneumatic pumps."

API believes that pneumatic pumps should be removed from this listing as control devices for pumps are not subject to performance testing.

F. Pump Closed Vent System Issues

As described in Item II.2. above, the compliance assurance requirements for a closed vent system (CVS) routing emissions from a pneumatic pump to a control device should be aligned to the requirements for storage vessels and not centrifugal and reciprocating compressors as currently finalized. Updating the rule language to reflect this will resolve API's primary issue.

However, the language and references under §60.5410a will require close review and updates as well to ensure the proper intent is reflected. For example, currently, under §60.5410a(e)(2), the rule references complying with the closed vent system requirements under §60.5411a(a) and (d). §60.5411a(a) includes pneumatic pumps in the list of applicable equipment. However, §60.5411a(d) refers to the PE certification requirements that appear to apply to storage vessels in §60.5411a(d)(1).

Separately, in §60.5410a(e)(5), the rule language repeats §60.5410a(e)(2) for control devices not able to achieve 95% control (§60.5393a(4)) but says the closed vent system must comply with §60.5411a(c) and §60.5411a(d). §60.5411a(c) only applies to storage vessels. Therefore, in the current rule, it appears that §60.5410a(e)(5) mistakenly references §60.5411a(c) instead of §60.5411a(a).

Again, API believes that pump closed vent system should be aligned with the requirements for storage vessels and not the requirements for affected compressors. The above inconsistencies in the current rule text are provided here to highlight the need to ensure complete and clear updates occur throughout Subpart OOOOa to reflect this change.

Attachment 10

GPA Midstream Association, Request for Partial Reconsideration and Stay of EPA's Final Rule entitled Oil and Natural Gas Sector: Emission Standards for New, Modified, and Reconstructed Sources (Aug. 2, 2016) (excerpts)

August 2, 2016

Via first class mail and email

Administrator Gina McCarthy
Office of the Administrator
Environmental Protection Agency
William Jefferson Clinton Building
Mail Code 1101A
1200 Pennsylvania Ave NW,
Washington DC 20004

RE: Request for Partial Reconsideration and Stay of EPA's Final Rule entitled Oil and Natural Gas Sector: Emission Standards for New, Modified, and Reconstructed Sources, 81 Fed. Reg. 35,824 (June 3, 2016) (Docket No. EPA-HQ-OAR-2010-0505)

Dear Administrator McCarthy,

GPA Midstream Association ("GPA Midstream") respectfully requests that the U.S. Environmental Protection Agency ("EPA") Administrator grant partial reconsideration of a number of specific and discrete issues in EPA's Final Rule entitled Oil and Natural Gas Sector: Emission Standards for New, Modified, and Reconstructed Sources, 81 Fed. Reg. 35,824 (June 3, 2016) (the "Final Rule").

GPA Midstream has served the U.S. energy industry since 1921 as an incorporated non-profit trade association. GPA Midstream is composed of close to 100 corporate members of all sizes that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to in the industry as "midstream activities." Such processing includes the removal of impurities from the raw gas stream produced at the wellhead, as well as the extraction for sale of natural gas liquid products ("NGLs") such as ethane, propane, butane and natural gasoline. GPA Midstream members account for more than 90 percent of the NGLs produced in the United States from natural gas processing. GPA Midstream's members also operate hundreds of thousands of miles of domestic gas gathering lines and are involved with storing, transporting, and marketing natural gas and NGLs.

Introduction

GPA Midstream and its members have a strong commitment to gathering and processing natural gas in a manner that minimizes environmental impacts and reduces emissions of valuable natural gas products to the fullest extent feasible. As a result, GPA Midstream's members have taken significant steps to reduce methane and volatile organic compound ("VOC") emissions from their operations. A number of GPA Midstream's members are voluntary participants in

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

EPA's Natural Gas Star Program where they have reduced methane emissions in accordance with EPA's program requirements. As *The Wall Street Journal* recently reported, over the last decade, methane emissions from the natural gas sector have declined significantly:

> The EPA's Greenhouse Gas Inventory acknowledged this year that methane emissions from natural gas production have fallen 35% since 2007. That's despite a 22% increase in gas production over the same period. The EPA last year found that methane emissions from hydraulically fractured gas wells had fallen 73% from 2011 to 2013. Overall methane emissions are 17% lower than in 1990.[1]

In addition, GPA Midstream has a long history of working collaboratively with state and federal regulators to identify commonsense solutions on a wide range of regulatory issues—including many environmental issues. GPA Midstream hopes to continue that collaborative working relationship with EPA through this rulemaking and reconsideration process.

After reviewing EPA's Final Rule, GPA Midstream has identified several specific and discrete issues that will pose implementations challenges and require reconsideration and/or clarification. The changes requested will still enable EPA to realize its environmental protection goals while at the same time reflecting the pragmatic practices and realities faced by this complex industry.

- First, EPA must increase the 0° Fahrenheit temperature threshold for waiving quarterly leak detection monitoring to 32° Fahrenheit. EPA failed to provide notice that it was considering a temperature-based waiver. A higher temperature is necessary to protect workers from exposure to inclement weather at locations where average temperatures may exceed 0° Fahrenheit, but the combination of cold temperatures, wind, and lack of access to warm structures may pose substantial risk to monitoring personnel.

- Second, EPA must revise the definition of well site to explicitly exclude equipment owned and operated by midstream operators. The definition in the Final Rule is ambiguous and, based on EPA's Response to Comments, this ambiguity could potentially be misinterpreted to include some midstream assets. Upstream producers and midstream operators are legally distinct and it would be both unreasonable and costly to subject midstream operators to leak detection monitoring requirements based on the independent actions of third parties.

- Third, EPA must remove compressors from the definition of fugitive emissions components. Compressors are separately regulated under Subparts OOOO and OOOOa and including them within the definition of fugitive emissions

[1] *Political Target: Natural Gas: The methane rule is part of a regulatory wave to raise drilling costs, The Wall Street Journal* (Aug. 23, 2015).

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

components is duplicative and will provide no added value to EPA while adding significant unnecessary burdens to industry.

- Fourth, EPA must add "the collection of fugitive emission components" at a compressor station to the list of sources that are exempt from reconstruction notification requirements under 40 C.F.R. § 60.15. Collections of fugitive emissions components are subject to the same notification of reconstruction requirements as other sources listed in 40 C.F.R. § 60.5420(a) and should be allowed the same exemption.

- In addition, GPA Midstream supports two items related to Certification by a Professional Engineer ("PE") requirements for which the American Petroleum Institute ("API") has petitioned for reconsideration. Specifically, API requested that the requirements for Certification by a PE finalized for technical infeasibility determinations at brownfield sites be removed and stayed pending reconsideration, and that EPA clarify when a greenfield site transitions to a brownfield site.

GPA Midstream is respectfully requesting that EPA grant reconsideration on these issues and make the necessary changes to clarify the obligations imposed on GPA Midstream's members and to improve implementation of the Final Rule. Because these issues are narrow and discrete they can be addressed by EPA through the reconsideration process without impacting implementation of the rest of the Final Rule or any litigation with respect to the rest of the Final Rule.

I. Standard for Reconsideration

Section 307(d)(7)(B) of the Clean Air Act ("CAA") provides for EPA's reconsideration of a CAA rule upon objection by a petitioner. *See* 42 U.S.C. § 7607(d)(7)(B). EPA *must* grant reconsideration when the petitioner:

> [C]an demonstrate to the Administrator that it was impracticable to raise [an] objection [during the period for public comment] or if the grounds for such objection arose after the period for public comment . . . and if such objection is of central relevance to the outcome of the rule.

Id. In such a situation, reconsideration is mandatory, as the CAA commands that EPA "*shall* convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." *Id.* (emphasis added). In addition, general principles of administrative law permit an interested party to apply to EPA for relief from a rule at any time for any relevant reason.

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

This Petition satisfies the standard for reconsideration. EPA included new provisions in the Final Rule that EPA did not specifically address in its rulemaking proposal. Thus, GPA Midstream was not afforded the opportunity to comment on those newly-included elements of the rule. It was therefore impracticable for GPA Midstream to raise objections to these provisions during the public comment period, and reconsideration is necessary with an accompanying stay. See 42 U.S.C. § 7607(d)(7)(B).

Further, EPA's inclusion of significant new issues in the Final Rule is arbitrary and capricious because none of the new additions are logical outgrowths of the Agency's Proposed Rule. The D.C. Circuit has admonished that, "[g]iven the strictures of notice-and-comment rulemaking, an agency's proposed rule and its final rule may differ only insofar as the latter is a logical outgrowth of the former." *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005). "Whether the 'logical outgrowth' test is satisfied depends on whether the affected party 'should have anticipated' the agency's final course in light of the initial notice." *Agape Church, Inc. v. FCC*, 738 F.3d 397, 412 (D.C. Cir. 2013) (quoting *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 548-49 (D.C. Cir. 1983). Interested parties should not have to "divine the agency's unspoken thoughts," *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1080 (D.C. Cir. 2009), or engage in telepathy, *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 186 (D.C. Cir. 2011). Instead, an agency "must describe the range of alternatives being considered with reasonable specificity. Otherwise, interested parties will not know what to comment on, and notice will not lead to better-informed agency decision-making." *Prometheus Radio Project v. FCC*, 652 F.3d 431, 450 (3d Cir. 2011) (internal citations omitted). Thus, a court will strike down an agency action that seeks to "use the rulemaking process to pull a surprise switcheroo on regulated entities." *Envtl. Integrity Project*, 425 F.3d at 998.

Further, the Final Rule includes inconsistent and duplicative provisions that cannot be adequately justified or explained. *See also Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (an agency must "articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made") (internal quotation omitted). As described below, these inconsistent and duplicative provisions will require GPA Midstream's members to comply with duplicative and potentially inconsistent regulations and further justify reconsideration.

II. Argument

A. EPA's Temperature-Based Waiver Provision for Quarterly Monitoring Surveys Is Not a Logical Outgrowth of the Proposed Rule and Must Be Clarified to Provide Meaningful Relief to Regulated Entities

In the Final Rule, EPA added a new temperature-based waiver provision for quarterly monitoring requirements when average monthly temperatures are below 0^{o} Fahrenheit for two out of three months in a quarter. 81 Fed. Reg. at 35,905 (40 C.F.R. § 60.5397a(g)(5). EPA's Proposed Rule did not indicate that the agency was considering such a temperature-based waiver

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

from monitoring requirements. As written, the waiver will provide no meaningful relief to GPA Midstream's members and must be clarified to ensure that regulated entities are not required to conduct monitoring that would be unsafe or infeasible due to inclement weather.

In the Proposed Rule, EPA included a series of provisions that required quarterly, semi-annual, or annual leak detection monitoring under different circumstances based on a company's history success in reducing methane leaks from compressor stations. *See* 80 Fed. Reg. at 56,668 (proposed 40 C.F.R. § 60.5397a(g)-(i)). EPA solicited comment on the appropriate frequency of leak detection monitoring for compressor stations, *id.* at 56,612-14, but did not suggest that it was considering the inclusion of waiver provisions based on temperature or any other factor.

In its comments on the Proposed Rule, GPA Midstream urged EPA to adopt uniform annual leak detection monitoring requirements for compressor stations. In support of its request for annual leak detection monitoring, GPA Midstream explained that sites located in northern and mountainous regions often experience significant snowfall and extreme temperatures that prevents access to some remote compressors stations for long periods of time. Allowing for annual leak detection monitoring would allow operators to conduct monitoring during summer months when weather conditions permitted.

In the Final Rule, EPA finalized requirements for quarterly leak detection monitoring, but added the following waiver provision for quarterly monitoring requirements:

> (5) The requirements of paragraph (g)(2) of this section are waived for any collection of fugitive emissions components at a compressor station located within an area that has an average calendar month temperature below 0 °Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of paragraph (g)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

80 Fed. Reg. at 56,668 (40 C.F.R. § 60.5397a(g)-(i)). In the preamble to the Final Rule, EPA explained that the waiver provision was included for two reasons. First, commenters explained that extreme winter weather created risk for the safety of monitoring survey personnel and also created access challenges when contractors were required to conduct surveys at unmanned sites. 81 Fed. Reg. at 35,862. EPA also expressed concern that optical gas imaging ("OGI") monitors may not perform correctly at temperatures below 0° Fahrenheit. *Id.*

GPA Midstream supports the inclusion of provisions that provide flexibility for conditions that make quarterly monitoring infeasible or unsafe. However, EPA's inclusion of a temperature-based waiver for quarterly reporting was announced for the first time in the Final Rule and thus is not a logical outgrowth of the Agency's proposal. EPA did not provide GPA

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

Midstream and other commenters with notice that it was considering a temperature-based waiver as a means of addressing challenges posed by quarterly leak detection monitoring. As a result of EPA's silence with respect to the potential waiver of leak detection monitoring requirements under certain circumstances, EPA failed to "describe the range of alternatives being considered with reasonable specificity. *Prometheus Radio Project*, 652 F.3d at 450. The fact that one commenter suggested such a waiver after providing data about sub-zero Fahrenheit temperatures is irrelevant. EPA cannot bootstrap notice from a comment. *The Fertilizer Institute v. EPA*, 935 F.2d 1303, 1312 (D.C. Cir. 1991). By failing to even mention the possibility for a temperature-based waiver, EPA deprived GPA Midstream of the opportunity to comment on such a proposal and explain to EPA what an appropriate temperature threshold might be and whether other waiver provisions might also be required.

Had GPA Midstream been given the opportunity to comment on the potential for waivers for quarterly leak detection monitoring requirements, it would have explained that additional flexibility is required to ensure that quarterly monitoring is feasible and will not endanger worker safety. As an initial matter, limiting the waiver to circumstances where the monthly average temperature of 0° Fahrenheit fails to provide meaningful relief to compressor station operators. First, very few locations in the United States experience sub-zero Fahrenheit average monthly temperatures for two out of three months, particularly when averaged over a three-year period. While one commenter noted that such cold temperatures occur in Nuiqsut, Alaska, EPA-HQ-OAR-2010-0505-6947, GPA Midstream is not aware of any location in the lower 48 states that could meet this standard and allow owners and operators of compressor stations to take advantage of this waiver provision. Moreover, the National Oceanic and Atmospheric Administration ("NOAA") sites used to calculate temperatures may not reflect the actual conditions at remote compressor stations which may be tens of miles from the NOAA monitoring sites and several thousand feet higher in elevation. As a result, the waiver provides no meaningful relief to the vast majority of regulated entities.

Second, a temperature threshold of 0° Fahrenheit is too low to accommodate the equipment EPA has identified for use in conducting leak detection monitoring. In the Final Rule, EPA allows operators to conduct fugitive emissions monitoring using either OGI or Method 21. *See, e.g.*, 81 Fed. Reg. at 35,846. EPA included Method 21 as an alternative method to give operators additional flexibility to continue to use existing equipment rather than purchasing new equipment or hiring new consultants to conduct leak detection monitoring. While EPA asserts in the Final Rule that OGI monitors can be used at temperatures below 0° Fahrenheit, this is not the same for the monitors approved under Method 21. For example, TVA model 1000B from Thermo Environmental Instruments is only certified for use at a temperature of 32° Fahrenheit or higher. Other Method 21 monitors also have temperature certifications at levels above 0° Fahrenheit. In addition, soap bubble monitoring is rendered unusable at temperatures below freezing. Because EPA also requires operators to make certifications regarding the accuracy of their monitoring equipment and the quality of their results, operators cannot use monitoring equipment outside of its certified temperature range. By effectively eliminating these alternative compliance options for cold-weather sites, EPA is eliminating

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

critical flexibility that will dramatically increase the cost of compliance with the Final Rule and may jeopardize compliance completely if the necessary equipment is not available.

Third, a monthly average temperature threshold of 0° Fahrenheit is far too low to protect the safety of monitoring survey personnel who would be required to spend significant amounts of time outside monitoring all of the required equipment at remote compressor stations. Even when temperatures are above 0° Fahrenheit, survey personnel could experience significant harm from exposure, particularly when wind chill is factored in. As the OSHA chart in Appendix A demonstrates, worker protection must be enhanced significantly as wind speed increases. In particular, exposure periods must be limited, more warm-up breaks are required, and workers must have access to warm locations to accommodate longer-term projects such as leak detection monitoring. Further, providing the necessary protection to workers and limiting their exposure time could significantly increase the amount of time needed to complete leak detection monitoring and EPA has not accounted for the associated costs in evaluating whether quarterly monitoring is cost-effective. In light of these risks, EPA must set an average monthly temperature threshold far above 0° Fahrenheit to adequately protect monitoring personnel at remote, unmanned compressor stations. Thus, GPA Midstream respectfully requests that EPA grant reconsideration with respect on this narrow issue and increase the temperature threshold for the waiver to 32° Fahrenheit.

In addition, EPA's temperature-based waiver does not provide any relief with respect to other circumstances that make leak detection monitoring difficult in inclement weather. Heavy snowpack, storms, and other winter conditions can make monitoring at remote locations impossible, even when average temperatures exceed 0° Fahrenheit. Based on GPA Midstream member's experience with other monitoring and testing crews, to accommodate busy schedules, site visits often must be schedule months when future weather conditions cannot be predicted with any accuracy. Thus, as a practical matter, conducting leak detection monitoring in winter months may prove infeasible due to inclement weather conditions that are only tangentially related to temperature. Thus, had GPA Midstream known that EPA was considering waiver provisions, it could have suggested additional alternatives that would provide more widespread relief. Therefore, GPA Midstream also requests that EPA grant reconsideration to provide additional relief for other inclement weather conditions that limit accessibility and will prevent operators from conducting quarterly monitoring at compressor stations.

B. EPA Must Clarify the Definition of Well Site to Exclude Equipment Owned and Operated by Midstream Pipeline Operators.

EPA must also grant reconsideration and revise the definition of well site to explicitly exclude equipment that is owned and operated by midstream pipeline operators. While certain midstream equipment may be co-located at well sites, such midstream equipment is not part of the production process at well sites and midstream operators should not become subject to leak detection monitoring requirements based on the independent actions of third-party well operators. Moreover, EPA's definition of well sites is vague and ambiguous and could be

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

interpreted to include equipment located far downstream and geographically separate from the actual well site. EPA must clarify and limit the definition of well site to avoid unnecessary and unwarranted costs on midstream operators.

In the Proposed Rule, EPA included the following definition of "well site":

> *Well site* means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at § 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

80 Fed. Reg. at 56,697. In comments on the Proposed Rule, GPA Midstream explained that upstream producers and midstream operators are legally distinct entities and urged EPA to clarify in the final rule that equipment owned and operated by midstream operators would not be subject to well site leak detection monitoring. The comments explained that in some circumstances—based on convenience or necessity—midstream assets may be co-located at well sites. But despite their proximity, GPA Midstream explained that the Clean Air Act did not permit EPA to define a source so broadly that it includes equipment owned and operated by legally distinct entities. GPA Midstream also explained the logistical and legal challenges that would occur if equipment owned and operated by midstream operators were subject to EPA's well site leak detection monitoring program. GPA Midstream proposed language for the definition of well site that would have fully excluded midstream equipment.

In the Final Rule, EPA made some changes to the definition of well site, but did not address GPA Midstream's concerns. Specifically, EPA defined well site as follows:

> *Well site* means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at § 60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

81 Fed. Reg. at 35,936. EPA made the revisions to address what it considered to be unclear language and to respond to comments about the status of centralized tank batteries. *Id.* at 35,861. These changes did nothing to address GPA Midstream's concerns about the potential inclusion of midstream equipment. In fact, they raise additional, new concerns about the inclusion of midstream equipment because the terms "one or more surface sites" and "subsequent operations" could be read expansively to include equipment that is far downstream and at a separate geographic location from a conventional well pad. Without a clear limit on the scope of a well site, such an interpretation could potentially encompass a significant amount of midstream assets.

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

Reconsideration is warranted because GPA Midstream was deprived of the opportunity to comment on these new terms and the way that they could potentially be applied to midstream equipment.

Reconsideration is also warranted as a result of EPA's subsequent statements in the Response to Comments document that provide for the first time additional insight into EPA's interpretation of these vague and ambiguous terms. In the Response to Comments document, EPA asserted that "[t]he collection of fugitive emission components at a well site, *regardless of the owner or operator*, is the affected facility and is subject to the fugitive emissions monitoring and repair program requirements specified in §60.5397a …." EPA, Response to Public Comments, Chapt. 4: Fugitives Monitoring at 221, EPA-HQ-OAR-2010-0505-7632 (emphasis added). EPA went on to state that, when a third party owned or operated equipment at a well site, it "believe[d] that resolution for any leaking components identified during surveys can be managed by the operator through cooperative agreements with other potential owners at the site." *Id.* Separately, EPA stated that it was "further clarifying the boundaries of a well site for purposes of the fugitive monitoring requirements. Our intent is to limit the oil and natural gas production segment up to the point of custody transfer *to an oil and natural gas mainline pipeline (including transmission pipelines) or a natural gas processing plant*. Therefore, the collection of fugitive emissions components within this boundary are a part of the well site." *Id.* at 194 (emphasis added). These statements announce, for the first time, a new and potentially expansive interpretation of well site that would pose substantial challenges for midstream operators. In addition, this interpretation of custody transfer deviates from EPA's long standing definition used in other New Source Performance Standards ("NSPS") regulations for the oil and gas industry. *See e.g.*, 40 C.F.R. § 60.111b ("Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation."). This definition of custody transfer is well-understood and much better conforms to the where transfer of custody typically occurs. Reconsideration is warranted here because GPA Midstream had no opportunity to comment on this interpretation of well site during the comment period on the Proposed Rule.

While EPA's interpretation correctly focuses on the transfer of custody as a key event in distinguishing a well site from downstream assets, it does so in a way that increases rather than decreases the likelihood that midstream assets will be included within the definition of well site. First, a natural gas mainline pipeline is a term of art used in the natural gas industry for a pipeline that is regulated by the Department of Transportation ("DOT"). The gathering lines operated by GPA Midstream's members are not typically subject to DOT regulation and thus are not considered natural gas mainline pipelines. Moreover, these gathering pipelines typically supply natural gas to processing plants and thus precede the point where natural gas is delivered to a natural gas processing plant. Under this purported interpretation of the definition of well site, a significant amount of midstream equipment might be considered part of the well site, even if it is physically separate and far downstream from an actual well pad. Such an interpretation would ignore entirely the legal distinction between upstream producers and midstream operators, as

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

well as EPA's longstanding definition of custody transfer in other NSPS regulations. EPA must grant reconsideration and revise the definition of well site to explicitly exclude all equipment owned and operated by all downstream entities, including midstream operators.

Failure to grant reconsideration and revise the definition would pose significant hardship on GPA Midstream's members. First, as a practical matter, midstream operators could become subject to leak detection monitoring requirements based solely on the acts of independent third-party upstream producers. In most cases, upstream producers have no obligation to inform midstream operators if they drill a new well, re-fracture an existing well, or take other action that EPA considers to be a modification or reconstruction. As a result, midstream operators could become subject to leak detection monitoring requirements (and potential enforcement actions) without ever knowing that such an obligation arose.

Second, EPA is incorrect to suggest that midstream operators can simply reach a cooperative agreement with upstream producers to conduct leak detection monitoring and make necessary repairs or replacements. Upstream producers and midstream operators already have complex, negotiated contracts in place that dictate the requirements of each party with respect to the gathering of natural gas, oil, condensate and/or water. It would be a monumental task to revise all of those contracts to include terms to govern leak detection monitoring and repair of fugitive emissions components owned and operated by midstream operators. Even if such cooperative agreements could be reached, EPA's certification requirements would prove problematic because midstream operators would be required to certify leak detection monitoring and repairs that were conducted by legally distinct third parties. Moreover, in many cases, midstream equipment located on well sites is propriety and upstream producers lack the authority to access the equipment to conduct monitoring and repairs. Thus, as a practical matter, it is likely that both upstream producers and midstream operators would have to separately conduct leak detection monitoring at well sites that contain co-located equipment. This would add significant and unnecessary costs to the leak detection monitoring program that EPA has not taken into account. In many cases, such leak detection monitoring may not be cost-effective for midstream operators who may have comparatively few assets located on well sites.

Therefore, GPA Midstream respectfully requests that EPA grant reconsideration and revise the definition of well site to explicitly exclude equipment owned and operated by midstream producers.

C. EPA Should Exclude Compressors from the Definition of Fugitive Emission Components

In the Final Rule, EPA substantially revised the definition of fugitive emission components in response to comments made by GPA Midstream and others. While GPA Midstream agrees that these revisions have improved EPA's regulations and provided some clarity regarding the leak detection monitoring requirements at compressor stations, it is concerned that EPA has included compressors within the definition of fugitive emission

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

components. *See* 81 Fed. Reg. at 35,934. As a result of this inclusion, compressors are subject to leak detection monitoring, repair and replacement requirements, and all of the other regulations applicable to the leak detection monitoring provisions in the Final Rule. Such regulations are wholly unnecessary because EPA has developed separate regulations in the Final Rule that are specifically designed to address compressors. Indeed, 40 C.F.R. §§ 60.5380a and 60.5385a provide emission reduction requirements for methane and VOC emissions that are directly applicable to centrifugal and reciprocating compressors, respectfully. These provisions are geared specifically for compressors and reflect what, in EPA's judgment, is the best system of emission reduction for compressors. Subjecting those same compressors to more the broadly applicable leak detection requirements for fugitive emission components is redundant at best and could potentially conflict with the compressor-specific requirements in 40 C.F.R. §§ 60.5380a and 60.5385a. Therefore, GPA Midstream urges EPA to grant reconsideration and remove compressors from the definition of fugitive emissions component.

D. EPA Must Clarify that "the Collection of Fugitive Emissions Components" at Compressor Station Sites Are Not Subject to the Reconstruction Notification Requirements of 40 C.F.R. § 60.15.

Finally, GPA Midstream requests that EPA grant this petition for reconsideration to clarify in Table 3 to Subpart OOOOa that the general reconstruction notification requirements in 40 C.F.R. § 60.15 do not apply to "the collection of fugitive emissions components" at compressor station sites. In the Proposed Rule, EPA explained that it was unnecessary for certain sources to comply with the notification of reconstruction requirements in 40 C.F.R. § 60.15(d) because those sources are already subject to specific reconstruction notification requirements in proposed 40 C.F.R. §§ 60.5410 and 60.5420. 80 Fed. Reg. at 56,647. The notification requirements EPA proposed for Subpart OOOOa in 40 C.F.R. §§ 60.5410a and 60.5420a mirror those in Subpart OOOO, rendering the requirements in 40 C.F.R. § 60.15 unnecessary for the same reasons. As a result, EPA proposed to include a reference in Table 3 to Subpart OOOOa specifying that 40 C.F.R. § 60.15(d) did not apply to pneumatic controllers pneumatic pumps, centrifugal compressors, or storage vessels. *Id.* at 56,698.

In response to comments that other sources were subject to the same notification requirements for reconstruction pursuant to proposed 40 C.F.R. § 60.5420a, EPA revised Table 3 in the Final Rule to also provide an exemption for wells and reciprocating compressors. 81 Fed. Reg. at 35,941. GPA Midstream supports these exemptions, but respectfully requests that EPA further revise Table 3 to also provide an exemption for collections of fugitive emissions components at compressor station sites. In both the Proposed Rule and Final Rule, EPA states:

> If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

80 Fed. Reg. at 56,688 (proposed 40 C.F.R. § 60.5420a(a)(1)); 81 Fed. Reg. at 35,927 (final 40 C.F.R. § 60.5420a(a)(1)). Thus the notification requirements in 40 C.F.R. § 60.5420(a) that EPA relies on for the exemptions in Table 3 apply to all of those sources, including collections of fugitive emissions components at compressor station sites. It would be arbitrary and capricious for EPA to require owners and operators of collections of fugitive emissions components to comply with the notification requirements in 40 C.F.R. § 60.15(d) while exempting other similarly situated sources.

III. EPA Must Stay the Final Rule Pending Reconsideration

Pending reconsideration, the Administrator should stay implementation of the portions of the Final Rule described above that will adversely affect GPA Midstream's members. Specifically, EPA should stay (1) quarterly leak detection monitoring requirements for compressor stations during the fourth and first quarters of each year, (2) any obligation to conduct well site leak detection monitoring for equipment owned by midstream operators, (3) the inclusion of compressors in leak detection monitoring for collections of fugitive emission components, and (4) the requirement to submit reconstruction notification requirements under 40 C.F.R. § 60.15(d) for fugitive emissions components located at compressor stations. Under the Administrative Procedure Act ("APA"), "[w]hen any agency finds that justice so requires, it may postpone the effective date of the action taken by it, pending judicial review." 5 U.S.C. § 705. EPA has applied this standard to Clean Air Act cases.[2] The standard for an administrative stay is significantly different from the standard for a stay used by the courts because it does not require a demonstration of irreparable harm. This is clear from the text of the APA:

> When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, the reviewing court . . . may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve the status or rights pending conclusion of the review proceedings.

Id. Thus, the APA deliberately contrasts what is required for an administrative stay—"justice so requires"—and a judicial stay—"conditions as may be required" and "irreparable harm." Similarly, Section 307(d)(7)(B) of the Clean Air Act also authorizes an administrative stay, but does not premise that stay on a finding of irreparable injury. Such differences must be given effect,[3] so there is no irreparable harm requirement for an administrative stay.

---

[2] *See, e.g., Ohio: Approval and Promulgation of Implementation Plans*, 46 Fed. Reg. 8,581, 8,582 n.1 (Jan. 27, 1981).

[3] "[W]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

Given the potential economic impact of these regulations on gas processors and the significance of the issues addressed above, justice and basic principles of good government require that EPA stay implementation of the portions of the Final Rule for which GPA Midstream is seeking reconsideration until EPA's reconsideration process is complete. The only express condition imposed on EPA's authority to grant a stay under Section 307 of the Clean Air Act is that EPA must have decided to reconsider the rule. As discussed above, the standard for reconsideration is met and it therefore follows that the standard for a stay under the Clean Air Act is also met. Further, in order to avoid significant adverse impacts on GPA Midstream's members of a rule that is arbitrary and capricious, justice requires that implementation of these portions of the Final Rule be stayed while EPA reconsiders and corrects errors in the Final Rule. Thus, the standard under Section 705 of the APA is also met.

While a stay is warranted under the standards established by both the CAA and APA, it would be justified even under the more stringent standard employed by the courts. Courts typically consider four factors in determining whether to grant a judicial stay: "(1) whether the stay applicant has made a strong showing that he is likely to succeed on the merits; (2) whether the applicant will be irreparably injured absent a stay; (3) whether issuance of the stay will substantially injure the other parties interested in the proceeding; and (4) where the public interest lies." *Nken v. Holder*, 129 S. Ct. 1749, 1761 (2009). These factors must be balanced against one another, such that "[a] stay may be granted with either a high probability of success and some injury, or vice versa." *Cuomo v. US Nuclear Reg. Comm'n*, 772 F.2d 972, 974 (D.C. Cir. 1985). All four factors are satisfied in this case.

First, as described above, GPA Midstream has identified legal, factual, and procedural flaws in EPA's rulemaking process and reconsideration is warranted on the merits.

Second, failure to grant a stay will irreparably harm GPA Midstream's members. For example, as described above, EPA's failure to provide meaningful waivers from quarterly monitoring requirements for cold and other inclement weather will create material health and safety risks for employees and other personnel hired to conduct leak detection monitoring surveys and, if necessary, repair or replace leaking parts. GPA Midstream's members will also suffer irreparable economic harm by being forced to acquire new monitoring equipment, engaging in time consuming leak detection monitoring during inclement weather, by conducting leak detection monitoring at well sites where they own equipment, but are not the site operator, and by complying with duplicative requirements. These harms cannot be remedied by prospective action to revise the Final Rule after granting reconsideration because the necessary costs—and potential harm to employees—will have already been incurred.

Third, there are minimal, if any, offsetting harms to third parties or the public interest from the stay sought by GPA Midstream. As described above, GPA Midstream's members have

---

exclusion." *Russello v. United States*, 464 U.S. 16, 23 (1983) (quotation marks and citations omitted; alteration in original).

GPA Midstream Association
Sixty Sixty American Plaza, Suite 700
Tulsa, Oklahoma 74135
(918) 493-3872

a strong economic interest in reducing methane emissions from their operations and have already taken significant voluntary efforts to reduce such emissions. Thus, temporarily staying the Final Rule while EPA completes the reconsideration process will have little, if any, discernible impact on methane emissions from the gas processing sector. The balance of harms and public interest, thus, favor granting a stay.

Conclusion

For the foregoing reasons, the Administrator must convene a limited proceeding for reconsideration of the Final Rule to address the discrete issues raised by GPA Midstream in this petition.

Respectfully submitted,

M Hite

Matt Hite
Vice President of Government Affairs
GPA Midstream Association
229 ½ Pennsylvania Avenue, SE
Washington, DC 20003
(202) 279-1664
mhite@gpaglobal.org

Cc (via email):
Janet McCabe, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA

APPENDIX A

Work/Warm-up Schedule for a 4-Hour Shift

Air Temperature--Sunny Sky		No Noticeable Wind		5 mph Wind		10 mph Wind		15 mph Wind		20 mph Wind	
°C (approximate)	°F (approximate)	Maximum Work Period	Number of Breaks	Maximum Work Period	Number of Breaks	Maximum Work Period	Number of Breaks	Maximum Work Period	Number of Breaks	Maximum Work Period	Number of Breaks
-26 to -28	-15 to -19	(Normal Breaks) 1		(Normal Breaks) 1		75 min	2	55 min	3	40 min	4
-29 to -31	-20 to -24	(Normal Breaks) 1		75 min	2	55 min	3	40 min	4	30 min	5
-32 to -34	-25 to -29	75 min	2	55 min	3	40 min	4	30 min	5	Non-emergency work should cease	
-35 to -37	-30 to -34	55 min	3	40 min	4	30 min	5	Non-emergency work should cease			
-38 to -39	-35 to -39	40 min	4	30 min	5	Non-emergency work should cease					
-40 to -42	-40 to -44	30 min	5	Non-emergency work should cease							
-43 & below	-45 & below	Non-emergency work should cease									

Schedule applies to any 4-hour work period with moderate to heavy work activity; with warm-up periods of ten (10) minutes in a warm location and with an extended break (e.g. lunch) at the end of the 4-hour work period in a warm location.

Adapted from ACGIH 2012 TLVs

Attachment 11

IPAA et al., Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources" (Aug. 2, 2016) (excerpts)

SPILMAN THOMAS & BATTLE, PLLC
ATTORNEYS AT LAW

James D. Elliott
717.791.2012
jelliott@spilmanlaw.com

August 2, 2016

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources"

Dear Administrator McCarthy:

The following trade associations hereby submit this petition for administrative reconsideration of the final rule entitled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," published at 81 Fed. Reg. 35824 (June 3, 2016) ("Subpart OOOOa" or "Methane NSPS"). We request that you take the time to review what and who these trade associations represent and not simply jump to the issues we are seeking reconsideration of. Many of these trade associations have been around since or before the 1950s. The trade associations represent the "independent" exploration and production companies – from the "mom and pop" operations to some of the larger producers in the country – but that is all they do and it is all they know. Subpart OOOOa, as finalized, will have a disproportionate impact on independents and especially independents that constitute "small business" under the Regulatory Flexibility Act. The issues raised in this petition fall into two categories: 1) issues that are entitled to reconsideration under Section 307(d)(7)(B) of the Clean Air Act ("CAA"), 42 U.S.C. § 7607(d)(7)(B), where it is impracticable to raise an objection during the period of public comment or if the grounds for such an objection arise after the public comment period (but within the time specified for judicial review), and if such objections are of central relevance to the outcome of the rule; and 2) issues the independents commented on, either through their trade association or as an individual company, that the U.S. Environmental Protection Agency ("EPA" or "Agency") failed to address in the final rule and that will have devastating impacts to the exploration and production segment of the industry if not addressed.

The national and state level trade associations joining in and filing this petition for reconsideration, collectively referred to as the "Independent Associations," are described below.

The Independent Petroleum Association of America ("IPAA") is an incorporated trade association that represents thousands of independent oil and natural gas producers and service companies across the United States that are active in the exploration and production segment of the industry, which often involves the hydraulic fracturing of wells. IPAA serves as an informed voice for the exploration and production segment of the industry, and advocates its members' views before the United States Congress, the Administration and federal agencies.

The American Exploration & Production Council ("AXPC") is an incorporated national trade association representing 29 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and the production of oil and natural gas. Moreover, its members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying the innovative and advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from non-conventional sources in environmentally responsible ways.

The Domestic Energy Producers Alliance ("DEPA") is a nationwide collaboration of 25 coalition associations, representing about 10,000 individuals and companies engaged in domestic onshore oil and natural gas production and exploration. Founded in 2009, DEPA gives a loud, clear voice to the majority of individuals and companies responsible for enduring work to secure our nation's energy future.

The Eastern Kansas Oil & Gas Association ("EKOGA") is a nonprofit organization founded in 1957 to become a unified voice representing the unique interests of eastern Kansas oil and gas producers, service companies, suppliers and royalty owners on matters involving oil and gas regulations, safety standards, environmental concerns and other energy related issues.

The Illinois Oil & Gas Association ("IOGA") was organized in 1944 to provide an agency through which oil and gas producers, land owners, royalty owners, and others who may be directly or indirectly affected by or interested in oil and gas development and production in Illinois, may protect, preserve and advance their common interests.

The Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), is a statewide nonprofit trade association that represents companies engaged in the extraction and production of natural gas and oil in West Virginia and the companies that support these extraction and production activities. IOGA-WV was formed to promote and protect a strong, competitive, and capable independent natural gas and oil producing industry in West Virginia, as well as the natural environment of their state.

The Indiana Oil and Gas Association ("INOGA") has a rich history of involvement in the exploration and development of hydrocarbons in the State of Indiana. INOGA was formed in 1942 and historically has been an all-volunteer organization principally made up of representatives of oil and gas exploration and development companies (operators), however, it has enjoyed support and membership from pipeline, refinery, land acquisition, service, supply, legal, engineering and geologic companies or individuals. INOGA has been an active representative for the upstream oil and gas industry in Indiana and provides a common forum for this group. INOGA represents its membership on issues of state, federal, and local regulation/legislation that has, does and will affect the business of this industry. INOGA is a

501(c)(6) trade association incorporated as Non-Profit Domestic Corporation under the statutes of Indiana.

Since 1940, the International Association of Drilling Contractors ("IADC") has exclusively represented the worldwide oil and gas drilling industry. IADC's contract-drilling members own most of the world's land and offshore drilling units that drill the vast majority of the wells producing the planet's oil and gas. IADC's membership also includes oil-and-gas producers, and manufacturers and suppliers of oilfield equipment and services. Through conferences, training seminars, print and electronic publications, and a comprehensive network of technical publications, IADC continually fosters education and communication within the upstream petroleum industry.

The Kansas Independent Oil & Gas Association ("KIOGA") is a nonprofit organization founded in 1937 to represent the interests of oil and gas producers in Kansas, as well as allied service and supply companies. Today, KIOGA is a trade association with over 4,200 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources.

The Kentucky Oil & Gas Association ("KOGA") was formed in 1931 to represent the interests of Kentucky's crude oil and natural gas industry, and more particularly, the independent crude oil and natural gas operators as well as the businesses that support the industry. KOGA is comprised of 220 companies which consist of over 600 member representatives that are directly related to the crude oil and natural gas industry in Kentucky.

The Michigan Oil And Gas Association ("MOGA") represents the exploration, drilling, production, transportation, processing, and storage of crude oil and natural gas in the State of Michigan. MOGA has nearly 850 members including independent oil companies, major oil companies, the exploration arms of various utility companies, diverse service companies, and individuals. Organized in 1934, MOGA monitors the pulse of the Michigan oil and gas industry as well as its political, regulatory, and legislative interest in the state and the nation's capital. MOGA is the collective voice of the petroleum industry in Michigan, speaking to the problems and issues facing the various companies involved in the state's crude oil and natural gas business.

The National Stripper Well Association ("NSWA") was founded in 1934 as the only national association *solely* representing the interests of the nation's smallest and most economically-vulnerable oil and natural gas wells before Congress, the Administration and the Federal bureaucracies. It is the belief of NSWA that producers, owners, and operators of marginally-producing oil and gas wells have a unique set of needs and concerns regarding federal legislation and regulation. NSWA is a member based trade association with nearly 800 members nationwide across 43 states.

The North Dakota Petroleum Council ("NDPC") is a trade association representing more than 590 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipeline, transportation, and storage, as well as mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky

Mountain Region. Established in 1952, NDPC's mission is to promote and enhance the discovery, development, production, transportation, refining, conservation, and marketing of oil and gas in North Dakota, South Dakota, and the Rocky Mountain region; to promote opportunities for open discussion, lawful interchange of information, and education concerning the petroleum industry; to monitor and influence legislative and regulatory activities on the state and national level; and to accumulate and disseminate information concerning the petroleum industry to foster the best interests of the public and industry.

The Ohio Oil & Gas Association ("OOGA") is a trade association with over 2,600 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources within the State of Ohio. OOGA represents the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio.

Founded in 1955, the Oklahoma Independent Petroleum Association ("OIPA") represents more than 2,500 individuals and companies from Oklahoma's oil and natural gas industry. Established by independent oil and natural gas producers hoping to provide a unified voice for the industry, OIPA is the state's largest oil and natural gas association and one of the industry's strongest advocacy groups.

The Pennsylvania Independent Oil & Gas Association ("PIOGA") is a non-profit corporation that was initially formed in 1978 as the Independent Oil and Gas Association of Pennsylvania ("IOGA of PA") to represent the interests of smaller independent producers of Pennsylvania natural gas from conventional limestone and sandstone formations. Effective April 1, 2010, IOGA of PA and another Pennsylvania trade association representing conventional oil and natural gas producers, Pennsylvania Oil and Gas Association ("POGAM"), merged and the name of the merged organization changed to its present name. PIOGA's membership currently is approximately 500 members: oil and natural gas producers developing both conventional and unconventional formations in Pennsylvania; drilling contractors; service companies; engineering companies; manufacturers; marketers; Pennsylvania Public Utility Commission-licensed natural gas suppliers ("NGSs"); professional firms and consultants; and royalty owners. PIOGA promotes the interests of its members in environmentally responsible oil and natural gas operations, as well as the development of competitive markets and additional uses for Pennsylvania-produced natural gas.

The Texas Alliance of Energy Producers ("Texas Alliance") became a statewide organization in 2000 with the merger of two of the oldest oil & gas associations in the nation: the North Texas Oil & Gas Association and the West Central Texas Oil & Gas Association. The Texas Alliance is now the largest statewide oil and gas association in the country representing Independents. With members in 34 states, the Texas Alliance works on behalf of our members at the local, state, and federal levels on issues vital to the industry.

The Texas Independent Producers & Royalty Owners Association ("TIPRO") is a trade association representing the interests of 3,000 independent oil and natural gas producers and royalty owners throughout Texas. As one of the nation's largest statewide associations representing both independent producers and royalty owners, members include small family businesses, the largest, publicly-traded independent producers, and mineral owners, estates, and trusts. Members of TIPRO are responsible for producing more than 85 percent of the natural gas and 70 percent of the oil within Texas, and own mineral interests in millions of acres across the state.

Chartered in 1915, the West Virginia Oil and Natural Gas Association ("WVONGA") is one of the oldest trade organizations in the State, and is the only association that serves the entire oil and gas industry. The activities of our members include construction, environmental services, drilling, completion, gathering, transporting, distribution, and processing.

The Independent Associations respectfully request the Agency reconsider the following issues.

A. SECTION 307(D)(7)(B) RECONSIDERATION ISSUES

1. The low production well (15 barrels of oil equivalent ("boe")/day) exemption from leak detection and repair ("LDAR") and reduced emission completions ("RECs") requirements should be reinstated in the final rule and the requirements regarding low production wells should be stayed pending reconsideration.

In the proposed rule, EPA sought comment on and proposed to exclude low production wells (i.e., those with an average daily production of 15 barrel equivalents or less per day) from REC and LDAR requirements. 80 Fed. Reg. 56633-34, 56639, 56665 (Sept. 18, 2015). The trades representing the independents uniformly supported the low production well exemptions. Based on the preamble discussion of the low production well exemption, EPA listened to, understood, and accepted the arguments and comments set forth by "small entities" during the Small Business Advocacy Review Panel ("Panel") process, in compliance with Section 609(b) of the Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 ("SBREFA"). Small entity representatives ("SERs"), including trade associations that are part of this petition, met with the Panel, which included EPA personnel, on May 19, 2015, and June 18, 2015, and submitted written comments. The SERs' message was clear – the potential REC and LDAR requirements would be the most onerous aspect of any additional controls on their operations. The SERs explained how and why these potential requirements would disproportionality impact small entities. The SERs explained the physical differences associated with low production wells (e.g., primarily pressure and volume) and the marginal profitability of low production wells. EPA seemed to "get it" and stated in the preamble:

> We believe the lower production associated with these wells [low production wells] would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement

> on small businesses, in particular where there is little emission reduction to be achieved.

80 Fed. Reg. 56639. Numerous oil and natural gas trade associations, including many of the parties to this petition filed comments in support of the exemptions and the rationale behind them.

Despite the information provided to EPA during the SBREFA process and Final Report of the Panel, EPA reversed course in the version of Subpart OOOOa and did not provide the low production exemption from either the REC or LDAR requirements. In the preamble to Subpart OOOOa that "one commenter" stated that low production wells have the "potential" to emit high fugitive emissions; "another commenter" stated that the LDAR survey should be conducted quarterly or monthly; and "one commenter" provided an estimate that a "significant" number of wells would be excluded under the low production well exemption. What appears to be EPA's principal reason for reversing course is that

> [S]takeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

81 Fed. Reg. 35856. EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a "modification" for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, i.e., the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then "honor" them in another context to eliminate an "emissions increase" requirement in the traditional definition of "modification."

The estimation or correlation of fugitive emissions with the number or types of components at low production versus non-low production wells was not discussed during the Panel process nor was comment sought by EPA in the proposed rule. If EPA proposed to correlate fugitive emissions at low production well sites with the number or types of components – in place of operating parameters such as line pressure and volume, independents would have been put on notice that additional information and comments were needed on the issue. No such comment was sought and EPA rationale and revocation of the low production well exemption is confounding. An administrative stay of the REC and LDAR requirements to low production wells is warranted pending outcome of the reconsideration proceeding. Although the effective date of the requirements has been extended 180 days, the impact of the regulations is immediate on low production wells. The marginal profitability will mean that many wells will be shut in instead of making the investment to conduct LDAR surveys. Similarly, low production wells that are currently in the planning stage will be reevaluated to take into consideration the additional costs of RECs and it is likely that the plans to drill many wells will be scrapped. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

2. The requirement in Section 60.5375a of Subpart OOOOa that requires a separator be "onsite during the entirety of the flowback period" was not part of the proposal and imposes an unnecessary cost on many conventional wells drilled by independents.

From the inception of the Subpart OOOO rulemaking, independent operators have informed the Agency that operating parameters during flowback of certain hydraulically fractured wells, often what is referred to as "conventional" wells, are such that a separator does not "work" – or as EPA has focused on is not technically feasible. EPA initially seems to understand this point and states:

> … we do not have sufficient data to consistently and accurately identify the subcategory or types of wells for which these circumstances occur regularly or what criteria would be used as the basis for an exemption to the REC requirement such that a separator would not be required to be onsite for these specific well completions. In order to accommodate these concerns raised by commenters, the final rule requires a separator to be onsite during the entire flowback period for subcategory 1 wells (i.e., non-exploratory or non-delineation wells, also known as development wells), but does not require performance of REC where a separator cannot function. We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use. For the reason stated above, we do not believe that requiring a separator onsite would incur cost with no environmental benefit.

81 Fed. Reg. 35881. Independent Associations take issue with the conclusion that requiring a separator onsite throughout the entire flowback period would incur no cost. The cost of having the separator on site is a significant cost and could be a limitation on the operations of certain operators. The existing regulations make clear that a separator must be utilized during the separation flowback stage and EPA has increased the record keeping and monitoring associated with the different stages of flow back. In addition to these requirements, there is the general duty clause to reduce emissions. The requirement to have a separator onsite throughout the flowback process is an unnecessary cost to many independent operators that provides no economic benefit. The proposed rule did not contemplate requiring a separator to be onsite throughout the flowback process and in fact inferred just the opposite. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

3. Subpart OOOOa added a variety of requirements associated with "technical infeasibility" that were not purposed or even mentioned in the proposed rule

that increase the cost of compliance with disproportionally impacts on independent operators.

While the Agency has appropriately accepted the concept that it is not technically feasible to implement certain controls, EPA added a number of requirements in Subpart OOOOa that were not proposed or discussed in the proposed rule:

- The final rule requires that Professional Engineers ("PE") certify connections of pneumatic pumps (§60.5393a) or closed vent systems (§60.5411a(d) are not technically feasible at brownfield sites. The certification by a PE will add considerable cost with no demonstrated benefits. As with many of these requirements. the independent operators do not have the ability in-house to meet these requirements and are dependent on third-party contractors. As EPA pushes the envelope on new/additional requirements, economies of scale favor the larger operators and to the extent the contractors are available for hire, it comes at a premium cost for the smaller entities and/or independent operators.
- Without discussion in the proposed rule, the Agency has also removed the "technical infeasibility" option for controls at "greenfields." Neither the proposed rule nor Subpart OOOOa define what constitutes a brownfield versus a greenfield. At some point in time a greenfield becomes a brownfield. Not only does the proposed rule fail to mention the concept of brownfield versus greenfield, Subpart OOOOa fails to provide any differentiation.
- The additional recordkeeping requirements added in Subpart OOOOa, at end of §60.5420a(c)(1)(iii)(A), associated with technical infeasibility, which were not part of the proposed rule, demonstrates that the Agency fails to understand that such requirements disproportionally impact small entities and many independent producers and operators.

The additional requirements associated with technical infeasibility were not only not addressed in the proposed rule, but the Agency failed to consider and address the disproportionate impact they would have on independent operators.

B. ADDITIONAL ISSUES IN NEED OF REVISION

The following issues were arguably addressed in some manner during the SBREFA and/or notice and comment process, but based on a review of the record, the Independent Associations believe they warrant additional discussion. The Independent Associations will provide the Agency additional information on these issues of concern.

1. The definition of "modification" as it relates to refractured wells and the LDAR requirements needs to be clarified and changed. The refracturing of wells does not necessarily mean emissions will increase. Emissions must increase to meet the NSPS definition of modification. As currently defined, Subpart OOOOa would unjustifiably subject "existing sources" that have not necessarily been modified to extensive and costly requirements.

2. Certain oil wells should be exempt from the LDAR requirements. Similarly, there should be a different definition of "low pressure well."

3. There should be an "off ramp" for the LDAR requirements when existing wells or new wells become "low production" or marginal wells.

4. Although Subpart OOOOa provides a state equivalency process for LDAR programs, the procedure set forth in the regulations (§60.5398a) is overly burdensome to the point that states are unlikely to avail themselves of the provisions.

5. The digital/video LDAR related requirements (§60.5420a) are unnecessary and should be removed.

6. EPA should reinstate options to reduce the emission surveys to annual surveys. While certain operators might prefer the consistency of bi-annual surveys, many independent operators and small entities would still benefit from the ability to reduce survey frequency by demonstrating few/no leaks during consecutive surveys.

7. Extended implementation periods are necessary and warranted for small entities that lack the bargaining power and resources (and the in-house capabilities) to contract with consultants to undertake the surveys, testing and documentation required by Subpart OOOOa. .

As indicated above, the Independent Associations will provide additional information on the issues raised above. In the interim, if the EPA has any questions or concerns, please do not hesitate to contact me.

Respectfully submitted,

James D. Elliott

Counsel to the Independent Associations

cc: Janet McCabe, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA

Attachment 12

TXOGA, Petition for Reconsideration (Aug. 2, 2016) (excerpts)

HUNTON & WILLIAMS LLP
575 MARKET STREET
SUITE 3700
SAN FRANCISCO, CALIFORNIA 94105

TEL 415 • 975 • 3700
FAX 415 • 975 • 3701

SHANNON S. BROOME
DIRECT DIAL: 415 • 975 • 3718
EMAIL: SBroome@hunton.com

August 2, 2016

VIA FACSIMILE-CERTIFIED MAIL-EMAIL

The Honorable Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Mail Code: 1101A
Washington, DC 20460
mccarthy.gina@epa.gov
Fax No: 202-501-1450

The Honorable Janet McCabe
Assistant Administrator
Office of Air and Radiation
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Mail Code: 6101A
Washington, DC 20460
mccabe.janet@epa.gov
Fax No: 202-501-0986

Re: Petition for Reconsideration

Dear Administrator McCarthy and Assistant Administrator McCabe:

Please find attached a Petition for Reconsideration filed on behalf of the Texas Oil & Gas Association with respect to the rule entitled, *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources;* Final Rule, 81 Fed. Reg. 35,824 (June 3, 2016), codified at 40 C.F.R. Part 60, EPA–HQ–OAR–2010-0505.

Feel free to contact me (415.975.3718) to discuss the Petition.

Sincerely,

Shannon S. Broome

Shannon S. Broome

Attachment

cc: Cory Pomeroy
Peter Tsirigotis

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN RE: OIL AND NATURAL GAS SECTOR: EMISSION STANDARDS FOR NEW, RECONSTRUCTED, AND MODIFIED SOURCES FINAL RULE, 81 FED. REG. 35,824 (JUNE 3, 2016)	DOCKET ID. NO. EPA–HQ–OAR–2010-0505

PETITION FOR RECONSIDERATION

by

THE TEXAS OIL & GAS ASSOCIATION

SHANNON S. BROOME
Hunton & Williams LLP
575 Market Street
Suite 3700
San Francisco, CA 94105
(415) 975-3718
sbroome@hunton.com

CHARLES H. KNAUSS
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, D.C. 20037
(202) 419-2003
cknauss@hunton.com

Counsel for the Texas Oil & Gas Association

Dated: August 2, 2016

I. INTRODUCTION

Pursuant to Section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), the Texas Oil and Gas Association (Petitioner or TXOGA) respectfully petitions the U.S. Environmental Protection Agency (EPA or Agency) to reconsider the nationally applicable final action entitled, *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule*, 81 Fed. Reg. 35,824 (June 3, 2016), codified at 40 C.F.R. Part 60, EPA–HQ–OAR–2010-0505 (Oil and Gas Subpart OOOOa Rule or Final Rule). TXOGA informs the Agency that TXOGA also filed today a petition for judicial review of the Oil and Gas Subpart OOOOa Rule and that it intends to raise in that litigation the issues on which reconsideration is requested below.

II. PETITIONER'S BACKGROUND AND RULEMAKING PARTICIPATION

The Texas Oil & Gas Association ("TXOGA") is a non-profit corporation representing the interests of the oil and natural gas industry in the State of Texas. Founded in 1919 and currently representing more than 5,000 members, TXOGA is the largest and oldest petroleum organization in Texas. The membership of TXOGA produces in excess of 90 percent of Texas' crude oil and natural gas, operates nearly 100 percent of the state's refining capacity and is responsible for the vast majority of the state's pipelines. The Texas oil and natural gas industry not only produces the products we use every day; it anchors our state's economy. In 2015 Texas' oil and natural gas industry paid $13.8 billion in taxes and royalties that directly fund our schools, roads and emergency services. An important element of TXOGA's purpose is to advocate the interests of its members on legislative and regulatory matters at the federal, state, and local levels. TXOGA has participated in EPA's proceedings leading to issuance of the Oil and Gas Subpart OOOOa Rule, having filed extensive comments on the Proposed Rule on December 4, 2015.[1]

III. BASES FOR RECONSIDERATION

A. EPA Must Convene a Reconsideration Proceeding Where, As Here, The Grounds for Reconsideration That Are of Central Relevance to the Outcome of a Rule Arose After the Close of the Comment Period.

Clean Air Act Section 307(d)(7)(B) provides:

> Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b) of this section). Such reconsideration shall not postpone the effectiveness of the rule. The effectiveness of the rule may be stayed during such reconsideration, however, by the Administrator or the court for a period not to exceed three months.[2]

The criteria for convening a reconsideration proceeding are plainly met here.

IV. ISSUES FOR WHICH TXOGA REQUESTS RECONSIDERATION

TXOGA has had the opportunity to review and discuss the petition for reconsideration filed by the American Petroleum Institute (API). We concur with and adopt the API petition as our own with respect to the following issues:

1) The requirements for Certification by Professional Engineer finalized in §60.5411a(d) for closed vent systems and §60.5393a for pneumatic pump technical infeasibility determination at brownfield sites should be removed and stayed pending reconsideration.

---

[1] *See* Comments of the Texas Oil & Gas Association on EPA's *Oil and Natural Gas Sector: Emission Standards for New and Modified Sources; Proposed Rule*, 80 Fed. Reg. 56,593 (Sept. 18, 2015), Docket No. EPA-HQ-OAR-2010-0505-7058.

[2] 42 U.S.C. § 7607(d)(7)(B) (emphasis added).

2) Coincident with PE certification requirements for pneumatic pump technical infeasibility determinations, EPA introduced but inadequately defined "greenfield" site as there is no clarity with respect to determining when a greenfield site transitions to a brownfield site. As well, it is inappropriate to categorically prohibit a claim of technical infeasibility for greenfield sites.
3) Clarification is required regarding location of separator finalized in §60.5375a for well completion operations.
4) The requirements in the final rule to document and report claims of technical infeasibility related to capturing of emissions during a well completion were not proposed and should be removed from the final rule.
5) Flares for control of Subpart OOOO affected facilities Should Not be Subject to 40 CFR § 60.18 retroactively.
6) Clarification is required for boilers and process heaters used to reduce emissions, particularly as used for pneumatic pumps.
7) The compliance assurance requirements for a closed vent system (CVS) routing emissions from a pneumatic pump to a control device should be aligned to the requirements for storage vessels and not centrifugal and reciprocating compressors as currently finalized.
8) There should be a pathway to reduce LDAR survey frequency to annual for well sites and semi-annual for compressor stations.
9) There should be an exemption from LDAR requirements for new low production wells and a pathway to discontinue LDAR at new wells that become low production wells.
10) Oil wells should be exempt from the LDAR requirements.
11) The timing of LDAR Surveys should be updated to allow for integration into existing LDAR programs.
12) The LDAR requirements must include adequate provisions to account for extreme weather in cold climates.
13) There should be a simple process for determining State Equivalency for the LDAR requirements at the State level; not just the process outlined in §60.5398a for Alternative Means of Emissions Limitations.
14) The definition of modification for LDAR should only include wells that are hydraulically refractured in combination with the installation of new production equipment on site.
15) The digital photo/video requirements associated with LDAR provision in §60.5420a should be removed.
16) Monitoring plan observation path and sitemap requirements under §60.5397a(d) are excessive and should be removed.
17) Delay of Repair Provisions require additional clarity.

18) Issues with Compliance Demonstration Requirements for Combustion Devices and Flares Not Addressed.

19) Requiring use of the Compliance and Emissions Data Reporting Interface (CEDRI) if EPA releases the electronic reporting form 90 days prior to the report due date is insufficient for compliance.

20) The definition of Capital Expenditure should be removed in §60.5430 of Subpart OOOO and the OOOOa procedure for calculating capital expenditure should be revised.

21) EPA should clarify that coil tubing cleanouts and screenouts are not subject to the provisions in §60.5430a.

22) Additional Technical Corrections.

Respectfully submitted,

Shannon S. Broome

Shannon S. Broome
Hunton & Williams LLP
575 Market Street
Suite 3700
San Francisco, CA 94105
(415) 975-3718
sbroome@hunton.com

Charles H. Knauss
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, D.C. 20037
(202) 419-2003
cknauss@hunton.com

Counsel for the Texas Oil & Gas Association

Dated: August 2, 2016

CERTIFICATE OF SERVICE

A copy of the preceding was sent on August 2, 2016 to the following *via* facsimile, certified mail and email:

The Honorable Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Mail Code: 1101A
Washington, DC 20004
mccarthy.gina@epa.gov
Fax No.: 202-501-1450

The Honorable Janet McCabe
Assistant Administrator
Office of Air and Radiation
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Mail Code: 6101A
Washington, DC 20460
mccabe.janet@epa.gov
Fax No.: 202-501-0986

U.S. Environmental Protection Agency
Correspondence Control Unit
Office of General Counsel
1200 Pennsylvania Avenue, NW
Mail Code: 2310A
Washington, DC 20460
garbow.avi@epa.gov

Shannon S. Broome

Shannon S. Broome

Attachment 13

Letter from E. Scott Pruitt, Administrator, U.S. EPA, to Howard J. Feldman, API, et al. (Apr. 18, 2017)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

April 18, 2017

THE ADMINISTRATOR

Mr. Howard J. Feldman
American Petroleum Institute
1220 L Street, NW
Washington, D.C. 20005

Ms. Shannon S. Broome
Counsel for the Texas Oil and Gas Association
Hunton & Williams LLP
575 Market Street, Suite 3700
San Francisco, California 94105

Mr. James D. Elliott
Counsel to the Independent Associations
Spilman Thomas & Battle PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, Pennsylvania 17050

Mr. Matt Hite
GPA Midstream Association
229 ½ Pennsylvania Avenue, SE
Washington, D.C. 20003

RE: Convening a Proceeding for Reconsideration of Final Rule, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources," published June 3, 2016, 81 Fed. Reg. 35824

Dear Mr. Feldman, Ms. Broome, Mr. Elliott and Mr. Hite:

This letter concerns petitions from the American Petroleum Institute, Texas Oil and Gas Association, Independent Associations and GPA Midstream Association, all dated August 2, 2016, to the U.S. Environmental Protection Agency requesting reconsideration, and in some circumstances an administrative stay, of provisions included in the EPA's final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources," 81 FR 35824 (June 3, 2016), pursuant to section 307(d)(7)(B) of the Clean Air Act and section 705 of the Administrative Procedure Act.

We find that the petitions have raised at least one objection to the fugitive emissions monitoring requirements included in the Final Rule (§60.5397a and associated provisions) that arose after the comment period or was impracticable to raise during the comment period and that is of central relevance to the rule under 307(d)(7)(B) of the CAA. Therefore, by this letter the EPA is convening a proceeding for reconsideration of those fugitive emissions monitoring requirements.

Among the issues raised in the petitions that meet the requirements for reconsideration under CAA section 307(d)(7)(B) are objections regarding the provisions for requesting and receiving an alternative means of emission limitations and the inclusion of low-production wells. These provisions, or certain aspects of these provisions, were not included in the proposed rule so the public could not have raised objections to these provisions during the public comment period. As part of the reconsideration process, the EPA will provide an opportunity for notice and comment on the issues raised in the petitions that meet the standard of CAA section 307(d)(7)(B), as well as any other matter we believe will benefit from additional comment.

As a result of this reconsideration, the EPA intends to exercise its authority under CAA section 307 to issue a 90-day stay of the compliance date for the fugitive emissions monitoring requirements. Sources will not need to comply with these requirements while the stay is in effect.

This letter does not address other requests for reconsideration raised in these and other petitions. Nor does it address the merits of, or suggest a concession of error on, any issue raised in the petitions.

If you have any questions concerning this action, please contact Mr. Peter Tsirigotis in the Office of Air Quality Planning and Standards at (888) 627-7764 or airaction@epa.gov.

Respectfully yours,

Scott Pruitt

E. Scott Pruitt

Attachment 14

Letter from Bakeyah Nelson, Air Alliance Houston, et al., to E. Scott Pruitt, Administrator, U.S. EPA (May 25, 2017)

May 25, 2017

Administrator E. Scott Pruitt
Office of the Administrator, Code 1101A
Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Re: Reconsideration and Stay of EPA's Methane New Source Performance Standards for the Oil and Natural Gas Sector

Dear Administrator Pruitt:

We write to convey our opposition to your April 18 decision to reconsider important provisions of the currently effective performance standards for new and modified sources in the oil and natural gas sector, which will reduce harmful methane, smog-forming pollution, and toxic emissions from these sources. We also oppose your stated intent to stay those provisions.

In a letter you sent to several oil and gas industry associations on April 18, you indicated that you intend to reconsider and stay requirements to find and fix equipment leaks, promising that "sources will not need to comply with these requirements while the stay is in effect." The current compliance date for these requirements is June 3, 2017. This stay will increase health risks for numerous Americans living in close proximity to wells and other facilities, which will emit significant amounts of additional hazardous and smog-forming pollution that would otherwise have been reduced. The stay will also add thousands of tons of methane, a highly potent greenhouse gas, to an atmosphere already overburdened with heat-trapping pollutants. Further, the stay will cause the waste of substantial volumes of valuable natural gas.

The leak detection and repair provisions that your letter threatens to stay are the cornerstone of EPA's methane standards. They require oil and gas operators to use proven, common-sense solutions to monitor their infrastructure and equipment in order to identify and then repair components that are leaking natural gas (the predominant component of which is methane) into the air. The agency projects that the leak detection and repair requirements alone will deliver over half of the rule's methane reductions and nearly 90 percent of its toxic air pollution reductions, including known human carcinogens like benzene. These protections also will result in substantial reductions of volatile organic compounds, which form ground-level ozone, the primary component of smog.

Suspending these requirements would allow thousands of newly-drilled or modified wells and compressor stations across the country to continue leaking large volumes of this harmful air pollution, posing serious health risks to communities, families, and workers. Such an action would leave the people living and working in these communities unprotected while delaying modest compliance expenditures by the oil and gas companies that own and operate new and modified wells—expenditures that represent a tiny fraction of these companies' tens of billions of dollars in annual revenues.

These measures are highly cost-effective, even without accounting for the climate and health benefits of preventing leaks. In public testimony on EPA's proposed rule, a leak detection and repair company indicated that it provides surveys for $250 per well, and other sources have documented similarly modest costs. Moreover, compliance with the leak detection and repair provisions will prioritize taxpayers' interests by ensuring resources that would otherwise be leaked to the atmosphere are instead captured and put to use. And greater adoption of methane mitigation practices will help to put Americans to work in the methane mitigation industry, which represents over 130 U.S. companies with locations in almost every state, helping to recover otherwise wasted natural gas. The stay will harm companies that provide methane mitigation technologies and services – 60% of which are small businesses.

EPA's methane standards are national protections that will ensure *all* communities benefit from these common sense best practices—and not just those located in states that have adopted such regulations. These proven state-level standards—including requirements in Colorado, Ohio, and Wyoming—demonstrate that protective pollution measures are entirely consistent with continued development and economic growth. The purpose of national standards under section 111 of the Clean Air Act is to ensure that all Americans are protected from sources of harmful pollution. The stay, however, will leave millions of Americans at risk.

A broad and diverse set of stakeholders supports the current oil and gas standards, including lawmakers in major producing states, small businesses, manufacturing workers' groups, investors, health professionals, public health groups, labor unions, and environmental organizations. Polling during the rule's comment period showed that 67 percent of Americans supported the proposed safeguards.

We strongly urge you to adhere to the rule's deadlines and not attempt to stay the leak detection and repair provisions.

You can contact Peter Zalzal at pzalzal@edf.org or 303-447-7214 to further discuss this request.

Respectfully submitted,

Bakeyah Nelson
Air Alliance Houston

Laura Belleville
Appalachian Trail Conservancy

Georgia Murray
Appalachian Mountain Club

Jessica Eckdish
BlueGreen Alliance

Rebecca Roter
Breathe Easy Susquehanna County

Deborah Burney-Sigman, Ph.D.
Breathe Utah

Jill Wiener
Catskill Citizens for Safe Energy

William Snape
Center for Biological Diversity

Veronica Coptis
Center for Coalfield Justice

Sue Chiang
Center for Environmental Health

Joseph Otis Minott, Esq.
Clean Air Council

Conrad Schneider
Clean Air Task Force

John Noël
Clean Water Action

Joseph K. Lyou, Ph.D.
Coalition for Clean Air

Benton Howell
Common Ground Rising

Pete Maysmith
Conservation Colorado

Sean Mahoney
Conservation Law Foundation

Demis Foster
Conservation Voters New Mexico
Conservation Voters New Mexico Education Fund

Timothy Ballo
Earthjustice

Lauren Pagel
Earthworks

Taylor Thomas
East Yard Communities for Environmental Justice

Peter Zalzal
Environmental Defense Fund

Adam Kron
Environmental Integrity Project

Howard A. Learner
Environmental Law & Policy Center

Diane Dreier
Gas Drilling Awareness Coalition of Luzerne County, Inc.

Amber Reimondo
Grand Canyon Trust

Todd Larsen
Green America

Tanja Srebotnjak
Harvey Mudd College

Susan Stephenson
Interfaith Power & Light

Madeleine Foote
League of Conservation Voters

Ranjana Bhandari
Liveable Arlington

Maureen Drouin
Maine Conservation Voters

Rebecca Boulos
Maine Public Health Association

Molly Rauch
Moms Clean Air Force

H. Drew Galloway
MOVE San Antonio

Shannon Heyck-Williams
National Wildlife Federation

David Doniger
Natural Resources Defense Council

Melinda Hughes
Nature Abounds

Joan Brown, OSF
New Mexico Interfaith Power & Light

Deborah Hanson
Northern Plains Resource Council

Melanie Houston
Ohio Environmental Council

Robert Altenburg
PennFuture

Barbara Gottlieb
Physicians for Social Responsibility

Karen D'Andrea
Physicians for Social Responsibility, Maine

Ned Ketyer, MD, FAAP
Walter Tsou, MD, MPD
Physicians for Social Responsibility, Philadelphia

Stephanie Thomas
Public Citizen

Barbara Jarmoska
Responsible Drilling Alliance

Michael Kellett
RESTORE: The North Woods

Tricia Cortez
Rio Grande International Study Center

Diane Duesterhoeft
San Antonio Interfaith Power & Light

Mark Pearson
San Juan Citizens Alliance

Andres Restrepo
Sierra Club

Glen Brand
Sierra Club, Maine

Dr. Cyrus Reed
Sierra Club, Lone Star Chapter

Raina Rippel
Southwest Pennsylvania Environmental Health Project

Robin Schneider
Texas Campaign for the Environment

Yaira Robinson
Texas Physicians for Social Responsibility

Chase Huntley
The Wilderness Society

Dan York
The Wildlands Conservancy

Harriett Jane Olson
United Methodist Women

Roy Houseman
United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union (USW)

James C. Harrison
Utility Workers Union of America, ALF-CIO

Steve Allerton
Western Colorado Congress

Thomas Singer, Ph.D.
Western Environmental Law Center

Sara Kendall
Western Organization of Resource Councils

Gary Wilmot
Wyoming Outdoor Council

Attachment 15

Letter from David Doniger, NRDC, et al., to E. Scott Pruitt, Administrator, U.S. EPA (June 1, 2017)

June 1, 2017

Administrator E. Scott Pruitt
Office of the Administrator, Code 1101A
Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Request for Withdrawal of Stay of Methane Oil and Gas NSPS Provisions

Dear Administrator Pruitt,

The undersigned organizations respectfully request that you withdraw the 90-day stay of provisions of the 2016 New Source Performance Standard for the Oil and Gas Industry Sector that you signed on May 26 and posted publicly yesterday at https://www.epa.gov/sites/production/files/2017-05/documents/frn_90daystay.pdf.

The undersigned are among the more than 60 organizations who wrote you on May 25, 2017, to ask you not to stay the long-sought leak detection and repair requirements scheduled to take full effect on June 3, 2017. The stay as issued yesterday covers those leak detection and repair requirements, plus two additional requirements of the Rule that you signaled an intent to stay only yesterday.

The stay should be withdrawn in its entirety because you lack legal authority to stay these regulations under section 307(d)(7)(B) of the Clean Air Act. A stay under this provision requires a valid reconsideration proceeding under that subparagraph of the Act. A reconsideration proceeding may be opened *only* if based on objections that could not practicably have been raised during the comment period in the rulemaking, and if the issues are of central relevance to the outcome of the rule. In this case, none of the objections on which you purported to have opened a reconsideration proceeding meets these threshold requirements.

First, the objections were in fact raised during the comment period, in some cases by multiple commenters. Second, EPA's dispositions of the matters in question were without question logical outgrowths of the original proposal and the comments received. Third, the objections are not of central relevance to the outcome of the rule. Further, the stay is illegally overbroad because it affects far more of the Rule's requirements than are implicated by the narrow objections on which you purport to base reconsideration.

Without the predicate of valid bases for reconsideration, you have no authority to issue a stay.

Whatever authority you may have to initiate new rulemaking with a view to possibly changing an existing regulation, you must do so through a notice and comment rulemaking that complies with section 307(d)(1) through (6) of the Act. Those provisions for new rulemaking do not include any authority to stay existing regulations. Where, as here, the threshold conditions for reconsideration under section 307(d)(7)(B) are not present, existing regulations must remain in effect until validly changed.

As the May 25 letter explains, your stay will cause irreparable harm to thousands of the members of the undersigned organizations and many thousands of similarly situated Americans. It will increase health risks for numerous Americans living in close proximity to covered wells and other facilities, which will emit significant amounts of additional hazardous and smog-forming pollution that would otherwise have been reduced. The stay will also add thousands of tons of methane, a highly potent greenhouse gas, to an atmosphere already overburdened with heat-trapping pollutants, harming all Americans at risk of climate change, and wasting substantial volumes of natural gas.

For these reasons, we respectfully ask that you withdraw the stay immediately so that the Rule will take full effect on June 3, 2017, as required.

As lead contact for the signatories, you can contact ddoniger@nrdc.org or (202) 289-2403 to further discuss this request.

Respectfully submitted,

Peter Zalzal
Environmental Defense Fund
2060 Broadway, Ste. 300
Boulder, CO 80302

Darin Schroeder
Clean Air Task Force
18 Tremont, Suite 530
Boston, MA 02108
Counsel for Earthworks

Adam Kron
Environmental Integrity Project
1000 Vermont Ave. NW, Suite 1100
Washington, DC 20005

David Doniger
Natural Resources Defense Council
1152 15th St. NW, Suite 300
Washington, DC 20005

Tim Ballo
Earthjustice
1625 Massachusetts Ave., NW
Suite 702
Washington, DC 20036
Counsel for Sierra Club and Clean Air Council

Joanne Marie Spalding
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612

Attachment 16

U.S. EPA, Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, **Proposed Rule**, 80 Fed. Reg. 56,593 (Sept. 18, 2015) (excerpts)

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9929–75–OAR]

RIN 2060–AS30

Oil and Natural Gas Sector: Emission Standards for New and Modified Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes to amend the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category. The Environmental Protection Agency (EPA) is including requirements for methane emissions in this proposal because methane is a greenhouse gas (GHG), and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations. The EPA is proposing both methane and VOC standards for several emission sources not currently covered by the NSPS and proposing methane standards for certain emission sources that are currently regulated for VOC. The proposed amendents also extend the current VOC standards to the remaining unregulated equipment across the source category and additionally establish methane standards for this equipment. Lastly, amendments to improve implementation of the current NSPS are being proposed which result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, final NSPS for the oil and natural gas sector and related amendments. Except for the implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the current standards.

DATES: Comments. Comments must be received on or before November 17, 2015. Under the Paperwork Reduction Act(PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before November 17, 2015. The EPA will hold public hearings on the proposal. Details will be announced in a separate announcement.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2010–0505, to the Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e. on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Instructions: All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. Direct your comments to Docket ID Number EPA–HQ–OAR–2010–0505. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or email. (See section III.B below for instructions on submitting information claimed as CBI.) The *www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you submit an electronic comment through *www.regulations.gov,* the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. If you send an email comment directly to the EPA without going through *www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. Electronic files should avoid the use of special characters, any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at: *www.epa.gov/epahome/dockets.htm.*

Docket: The EPA has established a docket for this rulemaking under Docket ID Number EPA–HQ–OAR–2010–0505. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, EPA WJC West Building, Room Number 3334, 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For information concerning this action, or for other information concerning the EPA's Oil and Natural Gas Sector regulatory program, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 541–3470; email address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION: *Outline.* The information presented in this preamble is organized as follows:

I. Preamble Acronyms and Abbreviations

Several acronyms and terms are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

ANGA America's Natural Gas Alliance
API American Petroleum Institute
bbl Barrel
BID Background Information Document
BOE Barrels of Oil Equivalent
bpd Barrels Per Day
BSER Best System of Emissions Reduction
BTEX Benzene, Toluene, Ethylbenzene and Xylenes
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous Parametric Monitoring Systems
EIA Energy Information Administration
EPA Environmental Protection Agency
GOR Gas to Oil Ratio
HAP Hazardous Air Pollutants
HPD HPDI, LLC
LDAR Leak Detection and Repair
Mcf Thousand Cubic Feet
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act of 1995
OAQPS Office of Air Quality Planning and Standards
OGI Optical Gas Imaging
OMB Office of Management and Budget
OVA Olfactory, Visual and Auditory
PRA Paperwork Reduction Act
PTE Potential to Emit
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
scfh Standard Cubic Feet per Hour
scfm Standard Cubic Feet per Minute
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. Executive Summary

A. Purpose of the Regulatory Action

The purpose of this action is to propose amendments to the NSPS for the oil and natural gas source category. To date the EPA has established standards for emissions of VOC and sulfur dioxide (SO_2) for several operations in the source category. In this action, the EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category (*i.e.,* production, processing, transmission and storage). The EPA is including requirements for methane emissions in this proposal because methane is a GHG and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.1 The proposed amendments would require reduction of methane as well as VOC across the source category.

In addition, the proposed amendments include improvements to several aspects of the existing standards related to implementation. These improvements and the setting of standards for methane are a result of reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, NSPS (77 FR 49490) and on the September 13, 2013, amendments (78 FR 58416). Except for these implementation improvements, these proposed amendments do not change the requirements for operations and equipment already covered by the current standards.

B. Summary of the Major Provisions of the Regulatory Action

The proposed amendments include standards for methane and VOC for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas source category. These emission sources include those that are currently unregulated under the current NSPS (hydraulically fractured oil well completions, pneumatic pumps and fugitive emissions from well sites and compressor stations); those that are currently regulated for VOC but not for methane (hydraulically fractured gas well completions, equipment leaks at natural gas processing plants); and certain equipment that are used across the source category, but which the current NSPS regulates VOC emissions from only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors), with the exception of compressors located at well sites.

Based on the EPA's analysis (see section VIII), we believe it is important to regulate methane from the oil and gas sources already regulated for VOC emissions to provide more consistency across the category, and that the best system of emission reduction (BSER) for methane for all these sources is the same as the BSER for VOC. Accordingly, the current VOC standards also reflect the BSER for methane reduction for the same emission sources. In addition, with respect to equipment used category-wide of which only a subset of those equipment are covered under the NSPS VOC standards (i.e., pneumatic controllers, and compressors located other than at well sites), EPA's analysis shows that the BSER for reducing VOC from the remaining unregulated equipment to be the same as the BSER for those currently regulated. The EPA is therefore proposing to extend the current VOC standards for these equipment to the remaining unregulated equipment.

The additional sources for which we are proposing methane and VOC standards were evaluated in the 2014 white papers (EPA Docket Number EPA–HQ–OAR–2014–0557). The papers summarized the EPA's understanding of VOC and methane emissions from these sources and also presented the EPA's understanding of mitigation techniques (practices and equipment) available to reduce these emissions, including the efficacy and cost of the technologies and the prevalence of use in the industry. The EPA received 26 submissions of peer review comments on these papers, and more than 43,000 comments from the public. The information gained through this process has improved the EPA's understanding of the methane and VOC emissions from these sources and the mitigation techniques available to control them.

The EPA has also received extensive and helpful input from state, local and tribal governments experienced in these operations, industry organizations, individual companies and others with data and experience. This information has been immensely helpful in determining appropriate standards for the various sources we are proposing to regulate. It has also helped the EPA design this proposal so as to complement, not complicate, existing state requirements. EPA acknowledges that a state may have more stringent state requirements (*e.g.*, fugitives monitoring and repair program). We believe that affected sources already complying with more stringent state requirements may also be in compliance with this rule. We solicit comment on how to determine whether existing state requirements (*i.e.*, monitoring, record keeping, and reporting) would demonstrate compliance with this federal rule.

During development of these proposed requirements, we were mindful that some facilities that will be subject to the proposed EPA standards will also be subject to current or future requirements of the Department of Interior's Bureau of Land Management (BLM) rules covering production of natural gas on Federal lands. We believe, to minimize confusion and unnecessary burden on the part of owners and operators, it is important that the EPA requirements not conflict with BLM requirements. As a result, EPA and BLM have maintained an ongoing dialogue during development of this action to identify opportunities for alignment and ways to minimize potential conflicting requirements and will continue to coordinate through the agencies' respective proposals and final rulemakings.

Following are brief summaries of these sources and the proposed standards.

Compressors. The EPA is proposing a 95 percent reduction of methane and VOC emissions from wet seal centrifugal compressors across the source category (except for those located at well sites).[2] For reciprocating compressors across the source category (except for those located at well sites), the EPA is proposing to reduce methane and VOC emissions by requiring that owners and/or operators of these compressors replace the rod packing based on specified hours of operation or elapsed calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure. See sections VIII.B and C of this preamble for further discussion.

Pneumatic controllers. The EPA is proposing a natural gas bleed rate limit of 6 standard cubic feet per hour (scfh) to reduce methane and VOC emissions from individual, continuous bleed, natural gas-driven pneumatic controllers at locations across the source category other than natural gas processing plants. At natural gas processing plants, the proposed rule regulates methane and VOC emissions by requiring natural gas-operated pneumatic controllers to have a zero natural gas bleed rate, as in the current NSPS. See section VIII.D of this preamble for further discussion.

Pneumatic pumps. The proposed standards for pneumatic pumps would apply to certain types of pneumatic pumps across the entire source category. At locations other than natural gas processing plants, we are proposing that the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps be reduced by 95 percent if a control device is already available on site. At natural gas processing plants, the proposed standards would require the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps to be zero. See section VIII.E of this preamble for further discussion.

Hydraulically fractured oil well completions. For subcategory 1 wells (non-wildcat, non-delineation wells), we are proposing that for hydraulically fractured oil well completions, owners and/or operators use reduced emissions completions, also known as ''RECs'' or ''green completions,'' to reduce methane and VOC emissions and maximize natural gas recovery from well completions. To achieve these reductions, owners and operators of hydraulically fractured oil wells must use RECs in combination with a completion combustion device. As is specified in the rule for hydraulically fractured gas well completions, the rule proposed here does not require RECs where their use is not feasible (*e.g.*, if it technically infeasible for a separator to function). For subcategory 2 wells (wildcat and delineation wells), we are proposing that for hydraulically fractured oil well completions, owners and/or operators use a completion combustion device to reduce methane and VOC emissions. The proposed standards for hydraulically fractured oil well completions are the same as the requirements finalized for hydraulically fractured gas well completions in the 2012 NSPS and as amended in 2014 (see 79 FR 79018, December 31, 2014). See section VIII.F of this preamble for further discussion.

Fugitive emissions from well sites and compressor stations. We are proposing that new and modified well sites and compressor stations (which include the transmission and storage segment and the gathering and boosting segment) conduct fugitive emissions surveys

[2] During the development of the 2012 NSPS, our data indicatedd that there were no centrifugal compressors located at well sites. Since the 2012 NSPS, we have not received information that would change our understanding that there are no centrifugal compressors in use at well sites.

semiannually with optical gas imaging (OGI) technology and repair the sources of fugitive emissions within 15 days that are found during those surveys. We are also co-proposing OGI monitoring surveys on an annual basis for new and modified well sites, and requesting comment on OGI monitoring surveys on a quarterly basis for both well sites and compressor stations. Fugitive emissions can occur immediately on startup of a newly constructed facility as a result of improper makeup of connections and other installation issues. In addition, during ongoing operation and aging of the facility, fugitive emissions may occur. Under this proposal, the required survey frequency would decrease from semiannually to annually for sites that find fugitive emissions from fewer than one percent of their fugitive emission components during a survey, while the frequency would increase from semiannually to quarterly for sites that find fugitive emissions from three percent or more of their fugitive emission components during a survey. We recognize that subpart W already requires annual fugitives reporting for certain compressor stations that exceed the 25,000 Metric Ton CO_2e threshold, and request comments on the overlap of these reporting requirements.

Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. Based on this concept, we solicit comment on criteria we can use to determine whether and under what conditions well sites and other emission sources operating under corporate fugitive monitoring plans can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

Other reconsideration issues being addressed. The EPA is granting reconsideration of a number of issues raised in the administrative reconsideration petitions and, where appropriate, is proposing amendments to address such issues. These issues are as follows: Storage vessel control device monitoring and testing provisions, initial compliance requirements in § 60.5411(c)(3)(i)(A) for a bypass device that could divert an emission stream away from a control device, recordkeeping requirements of § 60.5420(c) for repair logs for control devices failing a visible emissions test, clarification of the due date for the initial annual report under the 2012 NSPS, flare design and operation standards, leak detection and repair (LDAR) for open-ended valves or lines, compliance period for LDAR for newly affected units, exemption to notification requirement for reconstruction, disposal of carbon from control devices, the definition of capital expenditure and initial compliance clarification. We are proposing to address these issues to clarify the rule, improve implementation and update procedures, as fully detailed in section IX.

C. Costs and Benefits

The EPA has estimated emissions reductions, costs and benefits for two years of analysis: 2020 and 2025. Actions taken to comply with the proposed NSPS are anticipated to prevent significant new emissions, including 170,000 to 180,000 tons of methane, 120,000 tons of VOC and 310 to 400 tons of hazardous air pollutants (HAP) in 2020. The emission reductions are 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOC, and 1,900 to 2,500 tons of HAP in 2025. The methane-related monetized climate benefits are estimated to be $200 to $210 million in 2020 and $460 to $550 million in 2025 using a 3 percent discount rate (model average).[3]

In addition to the benefits of methane reductions, stakeholders and members of local communities across the country have reported to the EPA their significant concerns regarding potential adverse effects resulting from exposure to air toxics emitted from oil and natural gas operations. Importantly, this includes disadvantaged populations.

The measures proposed in this action achieve methane and VOC reductions through direct regulation. The hazardous air pollutant (HAP) reductions from these proposed standards will be meaningful in local communities. In addition, reduction of VOC emissions will be very beneficial in areas where ozone levels approach or exceed the National Ambient Air Quality Standards for ozone. There have been measurements of increasing ozone levels in areas with concentrated oil and natural gas activity, including Wyoming and Utah. Several VOCs that commonly are emitted in the oil and natural gas source category are HAPs listed under Clean Air Act (CAA) section 112(b), including benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ‘‘BTEX’’) and n-hexane. These pollutants and any other HAP included in the VOC emissions controlled under the NSPS, including requirements for additional sources being proposed in this action, are controlled to the same degree. The co-benefit HAP reductions for the measures being proposed are discussed in the Regulatory Impact Analysis (RIA) and in the Background Technical Support Document (TSD) which are included in the public docket for this action.

The EPA estimates the total capital cost of the proposed NSPS will be $170 to $180 million in 2020 and $280 to $330 million in 2025. The estimate of total annualized engineering costs of the proposed NSPS is $180 to $200 million in 2020 and $370 to $500 million in 2025 when using a 7 percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the proposed NSPS are estimated to be $150 to $170 million in 2020 and $320 to $420 million in 2025, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf). These compliance cost estimates include revenues from recovered natural gas as the EPA estimates that about 8 billion cubic feet in 2020 and 16 to 19 billion cubic feet in 2025 of natural gas will be recovered by implementing the NSPS.

Considering all the costs and benefits of this proposed rule, including the resources from recovered natural gas that would otherwise be vented, this rule results in a net benefit. The quantified net benefits (the difference between monetized benefits and compliance costs) are estimated to be $35 to $42 million in 2020 using a 3 percent discount rate (model average) for climate benefits.[4] The quantified net benefits are estimated to be $120 to $150 million in 2025 using a 3 percent discount rate (model average) for climate benefits. All dollar amounts are in 2012 dollars.

[3] We estimate methane benefits associated with four different values of a one ton CH_4 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this summary, we present the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section XI and in the RIA.

[4] Figures may not sum due to rounding.

We did not find any nonair quality health and environmental impacts, or energy requirements associated with the use of OGI or Method 21 for monitoring, repairing and resurvey fugitive components at well sites. Based on the above analysis, we believe that the BSER for reducing fugitive methane and VOC emissions at well sites is a monitoring and repair standard based on semi-annual monitoring using OGI and resurvey using Method 21.

As mentioned above, OGI monitoring requires trained OGI personnel and OGI instruments. Many owners and operators, in particular small businesses, may not own OGI instruments or have staff who are trained and qualified to use such instruments; some may not have the capital to acquire the OGI instrument or provide training to their staff. While our cost analysis takes into account that owners and operators may need to hire contractors to perform the monitoring survey using OGI, we do not have information on the number of available contractors and OGI instruments. In light of our estimated 20,000 active wells in 2012 and that the number will increase annually, we are concerned that some owners and operators, in particular small businesses, may have difficulty securing the requisite OGI contractors and/or OGI instrumentation to perform monitoring surveys on a semi-annual basis. Larger companies, due to the economic clout they have by offering the contractors more work due to the higher number of wells they own, may preferentially retain the services of a large portion of the available contractors. This may result in small businesses experiencing a longer wait time to obtain contractor services. In light of the potential concern above, we are co-proposing monitoring survey on an annual basis at the same time soliciting comment and supporting information on the availability of trained OGI contractors and OGI instrumentation to help us evaluate whether owners and operators would have difficulty acquiring the necessary equipment and personnel to perform a semi-annual monitoring and, if so, whether annual monitoring would alleviate such problems.

Recognizing that additional data may be available, such as emissions from super emitters that may have higher emission factors than those considered in this analysis, we are also taking comment on requiring monitoring survey on a quarterly basis.

CAA section 111(h)(1) states that the Administrator may promulgate a work practice standard or other requirements, which reflects the best technological system of continuous emission reduction when it is not feasible to enforce an emission standard. CAA section 111(h)(2) defines the phrase ‘‘not feasible to prescribe or enforce an emission standard’’ as follows:

> [A]ny situation in which the Administrator determines that (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

The work practice standards for fugitive emissions from well sites are consistent with CAA section 111(h)(1)(A), because no conveyance to capture fugitive emissions exist for fugitive emissions components at a well site. In addition, OGI does not measure the extent the fugitive emissions from fugitive emissions components. For the reasons stated above, pursuant to CAA section 111(h)(1)(b), we are proposing work practice standards for fugitive emissions from the collection of fugitive emission components at well sites.

The proposed work practice standards include details for development of a fugitive emissions monitoring plan, repair requirements and recordkeeping and reporting requirements. The fugitive emissions monitoring plan includes operating parameters to ensure consistent and effective operation for OGI such as procedures for determining the maximum viewing distance and wind speed during monitoring. The proposed standards would require a source of fugitive emissions to be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We have historically allowed 15 days for repair/resurvey in LDAR programs, which appears to be sufficient time. Further, in light of the number of components at a well site and the number that would need to be repaired, we believe that 15 days is also sufficient for conducting the required repairs under the proposed fugitive emission standards.[103] That said, we are also soliciting comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites.[104]

Many recent studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources.[105] Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of components (e.g., gross emitters). Based on this information, we solicit comment on whether the fugitive emissions monitoring program should be limited to ‘‘gross emitters.’’

We believe that a properly maintained facility would likely detect very little to no fugitive emissions at each monitoring survey, while a poorly maintained facility would continue to detect fugitive emissions. As shown in our TSD, we estimate the number of fugitive emission components at a well site to be around 700. We believe that a facility with proper operation would likely find one to three percent of components to have fugitive emissions. To encourage proper maintenance, we are proposing that the owner or operator may go to annual monitoring if the initial two consecutive semiannual monitoring surveys show that less than one percent of the collection of fugitive emissions components at the well site has fugitive emissions. For the same reason, we are proposing that the owner or operator conduct quarterly monitoring if the initial two semi-annual monitoring surveys show that more than three percent of the collection of fugitive emissions components at the well site has fugitive emissions. We believe the first year to be the tune-up year to allow owners and operators the opportunity to refine the requirements of their monitoring/repair plan. After that initial year, the required monitoring frequency would be annual if a monitoring survey shows less than one percent of components to have fugitive emissions; semi-annual if one to three percent of total components have fugitive emissions; and quarterly if over three percent of total components have fugitive emissions. We solicit comment on this approach, including the percentage used to adjust the monitoring frequency. We also solicit comment on the appropriateness of performance based monitoring frequencies. We also solicit comment on the appropriateness of triggering different monitoring frequencies based on the percentage of components with fugitive emissions. Under the proposed standards, the affected facility would be

[103] In our TSD we estimate the number of fugitive emissions components to be around 700 and of those components we estimate that about 1 percent would need to be repaired.

[104] This timelines is consistent with the timeline originally established in 1983 under 40 CFR part 60 subpart VV.

[105]

defined as the collection of fugitive emissions components at a well site. To clarify which components are subject to the fugitive emissions monitoring provisions, we propose to add a definition to § 60.5430 for ''fugitive emissions component'' as follows:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump would be considered fugitive emissions.

Thus, all fugitive emissions components at the affected facility would be monitored for fugitive emissions of methane and VOC.

For the reasons stated in section VII.G.1, for purposes of the proposed standards for fugitive emissions at well sites, modification of a well site is defined as when a new well is drilled or a well at the well site (where collection of fugitive emissions components are located) is hydraulically fractured or refractured. As explained in that section, other than these events, we are not aware of any other physical change to a well site that would result in an increase in emissions from the collection of fugitive components at such well site. To clarify and ease implementation, we propose to define ''modification'' to include only these two events for purposes of the fugitive emissions provisions at well sites.

In the 2012 NSPS, we provided that completion requirements do not apply to refracturing of an existing well that is completed responsibly (i.e. green completions). Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. It has come to our attention that some owners and operators may already have in place, and are implementing, corporate-wide fugitive emissions monitoring and repair programs at their well sites that are equivalent to, or more stringent than our proposed standards. Such corporate efforts present the potential to further the development of LDAR technologies. To encourage companies to continue such good corporate policies and encourage advancement in the technology and practices, we solicit comment on criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards). We recognize that meeting an NSPS performance level should not, standing alone, be a basis for a source not becoming an affected facility.

For the reasons stated above, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well sites fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

We are requesting comment on whether the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites or just to those components that are connected to the fractured, refractured or added well. For some modified well sites, the fractured or refractured or added well may only be connected to a subset of the fugitive emissions components on site. We are soliciting comment on whether the fugitive emission requirements should only apply to that subset. However, we are aware that the added complexity of distinguishing covered and non-covered sources may create difficulty in implementing these requirements. However, we note that it may be advantageous to the operator from an operational perspective to monitor all the components at a well site since the monitoring equipment is already onsite.

As explained above, Method 21 is not as cost-effective as OGI for monitoring. That said, there may be reasons why and owner and operator may prefer to use Method 21 over OGI. While we are confident with the ability of Method 21 to detect fugitive emissions and therefore consider it a viable alternative to OGI, we solicit comment on the appropriate fugitive emissions repair threshold for Method 21 monitoring surveys. As mentioned above, EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm is generally detectable using OGI instrumentation provided that the right operating conditions (e.g., wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI As mentioned above, we believe that OGI. In light of the above, we solicit comment on whether the fugitive emissions repair threshold for Method 21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold).

While we did not identify OGI as the BSER for resurvey because of the potential cost associated with rehiring OGI personnel, there is no such additional cost for those who either own the OGI instrument or can perform repair/resurvey at the same time. Therefore, the proposed rule would allow the use either OGI or Method 21 for resurvey. When Method 21 is used to resurvey components, we are proposing that the component is repaired if the Method 21 instrument indicates a concentration less than 500 ppm above background. This has been historically used in other LDAR programs as an indicator of no detectable emissions.

The proposed standards would require that operators begin monitoring fugitive emissions components at a well site within 30 days of the initial startup of the first well completion for a new well or within 30 days of well site modification. We are proposing a 30 day period to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey. We are requesting comment on whether 30 days is an appropriate amount of time to begin conducting fugitive emissions monitoring.

We received new information indicating that some companies could experience logistical challenges with the availability of OGI instrumentation and qualified OGI technicians and operators to perform monitoring surveys and in some instances repairs. We solicit comment on both the availability of OGI instruments and the availability of qualified OGI technicians and operators to perform surveys and repairs.

We are proposing to exclude low production well sites (i.e., a low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) [106] from the standards for fugitives emissions from well sites. We believe the lower production associated with these wells would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement on small businesses, in particular where there is little emission reduction to be achieved. To more fully evaluate the exclusion, we solicit comment on the air emissions associated with low production wells, and the relationship between production and fugitive emissions. Specifically, we solicit comment on the relationship between production and fugitive emissions over time. While we have learned that a daily average of 15 barrel per day is representative of low production wells, we solicit comment on the appropriateness of this threshold for applying the standards for fugitive emission at well sites. Further, we solicit comment on whether EPA should include low production well sites for fugitive emissions and if these types of well sites are not excluded, should they have a less frequent monitoring requirement.

We are also requesting comment on whether there are well sites that have inherently low fugitive emissions, even when a new well is drilled or a well site is fractured or refractured and, if so, descriptions of such type(s) of well sites. The proposed standards are not intended to cover well sites with no fugitive emissions of methane or VOC. We are aware that some sites may have inherently low fugitive emissions due to the characteristics of the site, such as the gas to oil ratio of the wells or the specific types of equipment located on the well site. We solicit comment on these characteristics and data that would demonstrate that these sites have low methane and VOC fugitive emissions.

We are requesting comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future. We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM–33 approaches (*e.g.,* Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (*e.g.,* Rebellion photonics), and Airborne Differential Absorption Lidar (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring surveys should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies.

2. Fugitive Emissions From Compressor Stations

Fugitive emissions at compressor stations in the oil and natural gas source category may occur for many reasons (*e.g.,* when connection points are not fitted properly, or when seals and gaskets start to deteriorate). Changes in pressure and mechanical stresses can also cause fugitive emissions. Potential sources of fugitive emissions include agitator seals, distance pieces, crank case vents, blowdown vents, connectors, pump seals or diaphragms, flanges, instruments, meters, open-ended lines, pressure relief devices, valves, open thief hatches or holes in storage vessels, and similar items on glycol dehydrators (*e.g.,* pumps, valves, and pressure relief devices). Equipment that vents as part of normal operations, such as gas driven pneumatic controllers, gas driven pneumatic pumps or the normal operation of blowdown vents are not considered to be sources of fugitive emissions.

Based on our review of the public and peer review comments on the white paper and the Colorado and Wyoming state rules, we believe that there are two options for reducing methane and VOC fugitive emissions at compressor stations: (1) A fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs, or (2) a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Several public and peer reviewer comments on the white paper noted that these technologies are currently used by industry to reduce fugitive emissions from the production segment in the oil and natural gas industry.

Each of these control options are evaluated below based on varying the frequency of conducting the monitoring survey and fugitive emissions repair threshold (*e.g.,* the specified concentration when using Method 21 or visible identification of methane or VOC when an OGI instrument is used). For our analysis, we considered quarterly, semiannual and annual monitoring frequencies. For Method 21, we considered 10,000 ppm, 2,500 ppm and 500 ppm fugitive repair thresholds. The leak definitions for other NSPS referencing Method 21 range from 500–10,000 ppm. Therefore, we selected 500 ppm, 2,500 ppm and 10,000 ppm. For OGI, we considered visible emissions as the fugitive repair threshold (*i.e.,* emissions that can be seen using OGI). EPA's recent work with OGI indicate that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI instrumentation, provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI.[107]

In order to estimate fugitive emissions from compressor stations, we used component counts from the GRI/EPA report [108] for each of the compressor station segments. Fugitive emission factors from AP–42 [109] were used to estimate emissions from gathering and boosting stations in the production

[106] For the purposes of this discussion, we define 'low production well' as a well with an average daily production of 15 barrel equivalents or less. This reflects the definition of a stripper well property in IRC 613A(c)(6)(E).

[107] Draft Technical Support Document Appendices, Optical Gas Imaging Protocol (40 CFR part 60, Appendix K), August 11, 2015.

[108] Gas Research Institute/U.S. Environmental Protection Agency, Research and Development, Methane Emission Factors from the Natural Gas Industry, Volume 8, Equipment Leaks, June 1996 (EPA–600/R–96–080h).

[109] Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates, Table 2–4, November 1995 (EPA–453/R–95–017).

subpart OOOO a provision similar to subpart KKK, 40 CFR 60.632(a), which allows a compliance period of up to 180 days after initial start-up. The commenter was ''concerned that a modification at an existing facility or a subpart KKK regulated facility could subject the facility to Subpart OOOO LDAR requirements without adequate time to bring the whole process unit into compliance with the new regulation.'' [120]

We clarify that subpart OOOO, as promulgated in 2012, already includes a provision similar to subpart KKK, § 60.632(a), as requested in the comment. Specifically, § 60.5400(a) requires compliance with 40 CFR 60.482–1a(a), which provides that ''[e]ach owner or operator subject to the provisions of this subpart shall demonstrate compliance . . . within 180 days of initial startup.'' This provision applies to all new, modified, and reconstructed sources. With respect to modification, which was of specific concern to the commenter, a change to a unit sufficient to trigger a modification and thus application of the subpart OOOO LDAR requirements for on-shore natural gas processing plants would be followed by startup, which would mark the beginning of the 180 day compliance period provided in 40 CFR 60.482–1a(a) (incorporated by reference in subpart OOOO § 60.5400(a)).

9. Tanks Associated With Water Recycling Operations

In many cases, flowback water from well completions and water produced during ongoing production is collected, treated and recycled to reduce the volume of potable water withdrawn from wells or other sources. Large, non-earthen tanks are used to collect the water for recycling following separation to remove crude oil, condensate, intermediate hydrocarbon liquids and natural gas. These collection tanks used for water recycling are very large vessels having capacities of 25,000 barrels or more, with annual throughput of millions of barrels of water. In contrast, industry standard storage vessels commonly found in well site tank batteries and used to contain crude oil, condensate, intermediate hydrocarbon liquids and produced water typically have capacities in the 500 barrel range.

Pollutants Reviews, 76 FR 52738 (Aug. 23, 2011). Pp. 3, 32–33.

[120] Comments of the Gas Processors Association Regarding the Proposed Rule, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 FR 52738 (Aug. 23, 2011). Pp. 33.

In the 2012 NSPS, we had envisioned the storage vessel provisions as regulating the vessels in well site tank batteries and not these large tanks primarily used for water recycling. It was never our intent to cover these large water recycling tanks. It recently came to our attention that these water recycling tanks could be inadvertently subject to the NSPS due to the extremely low VOC content combined with the millions of barrels of throughput each year, which could result in a potential to emit VOC exceeding the NSPS storage vessel threshold of 6 tpy.[121] The EPA encourages efforts on the part of owners and operators to maximize recycling of flowback and produced water. We are concerned that the inadvertent coverage of these tanks under the NSPS could discourage recycling. It is our understanding that, due to the size and throughput of these tanks, combined with the trace amounts of VOC emissions that are difficult to control, that operators may choose to discontinue recycling to avoid noncompliance with the NSPS.

As a result, we are considering changes in the final rule to remove tanks that are used for water recycling from potential NSPS applicability. We solicit comment on approaches that could be taken to amend the definition of ''storage vessel'' or other changes to the NSPS that would resolve this issue without excluding storage vessels appropriately covered by the NSPS. In addition, we solicit comment on location, capacity or other criteria that would be appropriate for such purpose.

X. Next Generation Compliance and Rule Effectiveness

A. Independent Third-Party Verification

The EPA is taking comment on establishing a third-party verification program as discussed below. Third-party verification is when an independent third-party verifies to a regulator that a regulated entity is meeting one or more of its compliance obligations. The regulator retains the ultimate responsibility to monitor and enforce compliance but, as a practical matter, gives significant weight to the third-party verification provided in the context of a regulatory program with effective standards, procedures, transparency and oversight. While requiring regulated entities to monitor and report should improve compliance by establishing minimum requirements for a regulated entity's employees and managers, well-structured third-party compliance monitoring and reporting may further improve compliance.

[121] Letter from Obie O'Brien, Vice President—Government Affairs/Corporate Outreach, Apache Corporation, to EPA Docket, Docket ID Number EPA–HQ–OAR–2010–4755, April 20, 2015. Similar letters from Rockwater Energy Solutions (EPA–HQ–OAR–2010–4756) and Permian Basin Petroleum Association (EPA–HQ–OAR–2010–4757).

The third-party verification program would be designed to ensure that the third-party reviewers are competent, independent, and accredited, apply clear and objective criteria to their design plan reviews, and report appropriate information to regulators. Additionally, there would need to be mechanisms to ensure regular and effective oversight of third-party reviewers by the EPA and/or states which may include public disclosure of information concerning the third parties and their performance and determinations, such as licensing or registration.

The EPA is considering a broad range of possible design features for such a program under the following two scenarios: (A) Third-Party Verification of Closed Vent System Design and (B) Third-Party Verification of IR Camera Fugitives Monitoring Program. These include those discussed or included in the following articles, rules, and programs:

(1) Lesley K. McAllister, Regulation by Third-Party Verification, 53 B.C. L. REV. 1, 22–23 (2012);

(2) Lesley K. McAllister, THIRD–PARTY PROGRAMS FINAL REPORT (2012) (prepared for the Administrative Conference of the United States), available at *http://www.acus.gov/report/third-party-programs-final-report;*

(3) Esther Duflo *et al.,* Truth-Telling By Third-Party Auditors and the Response of Polluting Firms: Experimental Evidence From India, 128 Q. J. OF ECON. 4 at 1499–1545 (2013);

(4) EPA CAA Renewable Fuel Standard (RFS) program: The RFS regulations include requirements for obligated parties to, in relevant part, submit independent third-party engineering reviews to the EPA before generating Renewable Identification Numbers (RINs).[122]

(5) Massachusetts Underground Storage Tank (UST) third-party inspection program: The owners/operators of most underground storage tanks in Massachusetts are required to have their USTs inspected by third-party inspectors every three years. While the third-party inspectors are hired directly by the tank owners and operators, they report to the Massachusetts Department of Environmental Protection (MassDEP). The third parties conduct and document detailed inspections of USTs and piping systems, review facility recordkeeping to ensure it meets UST program requirements, and submit reports on their findings electronically to MassDEP.[123]

[122] EPA, Renewable Fuel Standards (RFS), *http://www.epa.gov/OTAQ/fuels/renewablefuels/.*

[123] MassDEP, Third-Party Underground Storage Tank (UST) Inspection Program, *http://*

(6) Massachusetts licensed Hazardous Waste Site Cleanup Professional program: Private parties who are financially responsible under Massachusetts law for assessing and cleaning up confirmed and suspected hazardous waste sites must retain a licensed Hazardous Waste Site Cleanup Professional (commonly called a ''Licensed Site Professional'' or simply an ''LSP'') to oversee the assessment and cleanup work.[124]

We have identified one potential area for third-party verification under this rule.

Professional Engineer Certification of Closed Vent System and Control Device Design and Installation

When produced liquids from oil and natural gas operations are routed from the separator to the condensate storage tank, a drop in pressure from operating pressure to atmospheric pressure occurs. This results in ''flash emissions'' as gases are liberated from the condensate stream due to the change in pressure. The magnitude of flash emissions can dwarf normal working and breathing losses of a storage tank. If the control system (closed vent system and control device, including pressure relief devices and thief hatches on storage vessels) cannot accommodate the peak instantaneous flow rate of flash emissions, working losses, breathing losses and any other additional vapors, this may cause pressure relief devices and thief hatches to ''pop'' and they may not properly reseat, resulting in immediate and potentially continuing excess emissions. Through our energy extraction enforcement initiative, we have seen this to be the case, due in large part to undersized control systems that may have been inadequately designed to accommodate only working and breathing losses of a storage tank. We have worked in conjunction with states, including Colorado, in conducting inspection campaigns associated with storage vessels. In two inspection campaigns, in two different regions, we recorded venting from thief hatches or other parts of the control system at over 60 percent of the tank batteries inspected. Another inspection campaign resulted in a much higher leak rate, with 23 of 25 tank batteries experiencing fugitive emissions.

One potential remedy for the inadequate design and sizing of the closed vent system would be to require an independent third-party (independent of the well site owner/operator and control device manufacturer), such as a professional engineer, to review the design and verify that it is designed to accommodate all emissions scenarios, including flash emissions episodes. Another element of the professional engineer verification could be that the professional engineer verifies that the control system is installed correctly and that the design criteria is properly utilized in the field.

Another approach to detecting overpressure in a closed vent system would be to require a continuous pressure monitoring device or system, located on the thief hatches, pressure relief devices and other bypasses from the closed vent system. Through our inspections, we have seen thief hatch pressure settings below the pressure settings of the storage tanks to which they are affixed. This results in emissions escaping from the thief hatch and not making it to the control device.

The EPA requests comment on these approaches. Specifically, we request comment as to whether we should specify criteria by which the PE verifies that the closed vent system is designed to accommodate all streams routed to the facility's control system, or whether we might cite to current engineering codes that produce the same outcome. We also request comment as to what types of cost-effective pressure monitoring systems can be utilized to ensure that the pressure settings on relief devices is not lower than the operating pressure in the closed vent to the control device and what types of reporting from such systems should be required, such as through a supervisory control and data acquisition (SCADA) system.

B. Fugitives Emissions Verification

As discussed in sections VII.G and VIII.G, the EPA is proposing the use of OGI as a low cost way to find leaks. While we believe we are proposing a robust method to ensure that OGI surveys are done correctly, we have ample experience from our enhanced leak detection and repair (LDAR) efforts under our Air Toxics Enforcement Initiative, that even when methods are in place, routine monitoring for fugitives may not be as effective in practice as in design. Similar to the audits included as part of consent decrees under the Initiative (*See U.S. et. Al.* v. *BP Products North America Inc.),* we are soliciting comment on an audit program of the collection of fugitive emissions components at well sites and compressor stations.

For this rule, we are anticipating a structure in which the facilities themselves are responsible for determining and documenting that their auditors are competent and independent pursuant to specified criteria. The Agency seeks comment as to whether this approach is appropriate for the type of auditing we describe below, or whether an alternative approach, such as requiring auditors to have accreditation from a recognized auditing body or EPA, or other potentially relevant and applicable consensus standards and protocols (*e.g.*, American National Standards Institute (ANSI), ASTM International (ASTM), European Committee for Standardization (CEM), International Organization for Standardization (ISO), and National Institute of Standards and Technology (NIST) standards), would be preferable.

In order to ensure the competence and independence of the auditor, certain criteria should be met. Competence of the auditor can include safeguards such as licensing as a Professional Engineer (PE), knowledge with the requirements of rule and the operation of monitoring equipment (*e.g.*, optical gas imaging), experience with the facility type and processes being audited and the applicable recognized and generally accepted good engineering practices, and training or certification in auditing techniques.

Independence of the auditor can be ensured by provisions and safeguards in the contracts and relationships between the owner and operator of the affected facility with auditors. These can include: The auditor and its personnel must not have conducted past research, development, design, construction services, or consulting for the owner or operator within the last 3 years; the auditor and its personnel must not provide other business or consulting services to the owner or operator, including advice or assistance to implement the findings or recommendations in the Audit report, for a period of at least 3 years following the Auditor's submittal of the final Audit report; and all auditor personnel who conduct or otherwise participate in the audit must sign and date a conflict of interest statement attesting the personnel have met and followed the auditors' policies and procedures for competence, impartiality, judgment, and operational integrity when auditing under this section; and must receive no financial benefit from the outcome of the Audit, apart from payment for the auditing services themselves. In addition, owners or operators cannot provide future employment to any of the auditor's personnel who conducted or otherwise participated in the Audit for a period of at least 3 years following the Auditor's submittal of its final Audit report and must be empowered to direct

www.mass.gov/eea/agencies/massdep/toxics/ust/third-party-ust-inspection-program.html.

[124] *http://www.mass.gov/eea/agencies/massdep/cleanup/licensed-site-professionals.html.*

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410a.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415a.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a.

§ 60.5390a What methane and VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the methane and VOC standards, based on natural gas as a surrogate for methane and VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in § 60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410a.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415a.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a, except that you are not required to submit the notifications specified in § 60.5420a(a).

§ 60.5393a What methane and VOC standards apply to pneumatic pump affected facilities?

For each pneumatic pump affected facility you must comply with the methane and VOC standards, based on natural gas as a surrogate for methane and VOC, in either paragraph (a)(1) or (b)(1) of this section, as applicable.

(a)(1) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

(2) Each pneumatic pump affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic pump as required in § 60.5420a(c)(16)(i).

(b)(1) Each pneumatic pump affected facility at a location other than a natural gas processing plant must reduce natural gas emissions by 95.0 percent, except as provided in paragraph (b)(2) of this section.

(2) You are not required to install a control device solely for the purposes of complying with the 95.0 percent reduction of paragraph (b)(1) of this section. If you do not have a control device installed on-site by the compliance date, then you must comply instead with the provisions of paragraphs (b)(2)(i) and (ii) of this section.

(i) Submit a certification in accordance with § 60.5420(b)(8)(i).

(ii) If you subsequently install a control device, you are no longer required to submit the certification in § 60.5420(b)(8)(i) and must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of installation of the control device. Compliance with this requirement should be reported in the next annual report in accordance with § 60.5420(b)(8)(iii).

(3) Each pneumatic pump affected facility at a location other than a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pump as required in § 60.5420a(c)(16)(i).

(4) If you use a control device to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of § 60.5411a(a) and route emissions to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c) and performance tested in accordance with § 60.5413a. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(c) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5410a.

(d) You must demonstrate continuous compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5415a.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a, except that you are not required to submit the notifications specified in § 60.5420a(a).

§ 60.5395a What VOC standards apply to storage vessel affected facilities?

Except as provided in paragraph (e) of this section, you must comply with the VOC standards in this section for each storage vessel affected facility.

(a) You must comply with either the requirements of paragraphs (a)(1) and