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Title 3—

The President

Proclamation 10304 of November 8, 2021

World Freedom Day, 2021

By the President of the United States of America

A Proclamation

For nearly 3 decades, the Berlin Wall stood as a physical symbol of the Cold War, dividing democratic West Berlin from communist East Berlin. Today, we remember the East Germans who escaped and those who died attempting to attain a life of freedom. We recognize the irrepressible human spirit that no wall could contain, which fueled the civil resistance, sacrifice, and courageous defiance of people across Central and Eastern Europe. We recall the euphoria and the hope of the East and West Berliners who gathered at the wall on November 9, 1989, chanting ''Tor auf!''—''Open the gate!''

It was the aspirations for freedom of the people of Central and Eastern Europe that ultimately brought down the Berlin Wall and overcame the Soviet Union's attempts to keep Europe divided by force. On World Freedom Day, we commemorate this historic event and honor all those who peacefully rose up and claimed their freedom and all those who continue their legacy by peacefully working to end tyranny and oppression in our world today.

Since the Berlin Wall was torn down in 1989, we have seen great progress to advance human rights and fundamental freedoms as well as to build and consolidate democratic institutions across the formerly communist countries of Central and Eastern Europe and around the world. However, democracy is still fragile, and in too many places it remains under threat. Authoritarians elevate their own power over the rights of their citizens, and around the world we see aspiring autocrats trample the rule of law, attack freedom of the press, and undermine an independent judiciary.

In the face of resurgent authoritarianism and attacks on human rights around the globe, the United States is working to support democratic renewal and resilience at home and abroad. It remains as important as ever to counter the range of threats to democracy—and, ultimately, peace and stability—including transnational repression, corruption, cyberattacks, disinformation, digital authoritarianism, inequality and injustice, voter suppression, and economic coercion.

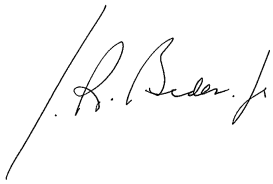
World Freedom Day also reminds us of the hopeful future people still seek for themselves around the world. In recent years, brave women and youths in Sudan have withstood violence and oppression to push a genocidal dictator from power and today continue to defend their democratic progress. Proud Moldovans helped deliver a victory for the forces of democracy. Citizens of Zambia, especially young people, turned out in historic numbers to elect their new president. Ukraine continues to make progress in countering corruption, safeguarding human rights, and strengthening its democratic institutions all while standing up to Russian aggression. Courageous anti-corruption activists, human rights defenders, journalists, and peace protestors in Belarus, Burma, Cuba, Hong Kong, Syria, Venezuela, and elsewhere continue to demand respect for their human rights and a democratic future. To all those who continue to endure repression under authoritarian regimes, know that the people of the United States stand with you.

Today, we reaffirm our commitment to the ideal that democracy—a Government of the people, by the people, and for the people—is how we best safeguard the rights, freedoms, and dignity that belong to every person.

Together with other free nations, the United States remains committed to the vital work of strengthening our democratic institutions, defending civil society, advancing human rights, and holding those who commit abuses and foster corruption accountable. To demonstrate this, on December 9–10, 2021, I will host a virtual Summit for Democracy to help set an agenda for democratic renewal across the globe.

NOW, THEREFORE, I, JOSEPH R. BIDEN JR., President of the United States of America, do hereby proclaim November 9, 2021, as World Freedom Day. I call upon the people of the United States of America to recall the hope symbolized by the fall of the Berlin Wall and reaffirm our dedication to freedom and democracy.

IN WITNESS WHEREOF, I have hereunto set my hand this eighth day of November, in the year of our Lord two thousand twenty-one, and of the Independence of the United States of America the two hundred and forty-sixth.



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Rules and Regulations

Federal Register

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DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2020–0103; Product Identifier 2019–NM–149–AD; Amendment 39–21718; AD 2021–18–17]

RIN 2120–AA64

Airworthiness Directives; The Boeing Company Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The FAA is superseding Airworthiness Directive (AD) 2012–21–08, which applied to certain The Boeing Company Model 737–600, –700, –700C, –800, and –900 series airplanes. AD 2012–21–08 required inspecting for part numbers of the operational program software (OPS) of the flight control computers (FCCs) and installing and testing an updated version of the FCC OPS. This AD was prompted by reports that during autopilot coupled instrument landing system (ILS) approaches, the airplane did not capture or track the glideslope correctly. This AD retains the requirement to inspect for part numbers of the OPS of the FCCs, and adds a new requirement to update the version of the FCC OPS if necessary. This AD also expands the applicability to include The Boeing Company Model 737–900ER series airplanes. The FAA is issuing this AD to address the unsafe condition on these products.

DATES: This AD is effective December 20, 2021.

The Director of the Federal Register approved the incorporation by reference of a certain publication listed in this AD as of December 20, 2021.

The Director of the Federal Register approved the incorporation by reference of certain other publications listed in this AD as of November 27, 2012 (77 FR 64711, October 23, 2012).

ADDRESSES: For service information identified in this final rule, contact Boeing Commercial Airplanes, Attention: Contractual & Data Services (C&DS), 2600 Westminster Blvd., MC 110–SK57, Seal Beach, CA 90740–5600; telephone 562–797–1717; internet *https://www.myboeingfleet.com.* You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195. It is also available at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2020–0103.

Examining the AD Docket

You may examine the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2020–0103; or in person at Docket Operations between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this final rule, any comments received, and other information. The address for Docket Operations is U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: Michael J. Tucker, Aerospace Engineer, Systems and Equipment Section, FAA, Seattle ACO Branch, 2200 South 216th St., Des Moines, WA 98198; phone and fax: 206–231–3974; email: *michael.j.tucker@faa.gov.*

SUPPLEMENTARY INFORMATION:

Background

The FAA issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 to supersede AD 2012–21–08, Amendment 39–17224 (77 FR 64711, October 23, 2012) (AD 2012–21–08). AD 2012–21–08 applied to certain The Boeing Company Model 737–600, –700, –700C, –800, and –900 series airplanes. The NPRM published in the **Federal Register** on February 27, 2020 (85 FR 11319). The NPRM was prompted by reports that during autopilot coupled ILS approaches, the airplane did not capture or track the glideslope correctly. In the NPRM, the FAA proposed to continue to require inspecting for part numbers of the OPS of the FCCs, and to add a new requirement to update the version of the FCC OPS if necessary. The NPRM also proposed to expand the applicability to include The Boeing Company Model 737–900ER series airplanes. The FAA is issuing this AD to address the glideslope capture problem, which could allow the airplane to descend below the glideslope beam and result in controlled flight into terrain on airplanes that do not have the upgraded FCC OPS installed.

Discussion of Final Airworthiness Directive

Comments

The FAA received comments from two commenters, including Air Line Pilots Association, International (ALPA) and United Airlines, who supported the NPRM without change.

The FAA received additional comments from three commenters, including Boeing, Alaska Airlines, and Aviation Partners Boeing. The following presents the comments received on the NPRM and the FAA's response to each comment.

Effect of Winglets on Accomplishment of the Proposed Actions

Aviation Partners Boeing stated that the installation of winglets per Supplemental Type Certificate (STC) ST00830SE does not affect the actions specified in the NPRM.

The FAA agrees with the commenter that STC ST00830SE does not affect the accomplishment of the manufacturer's service instructions. Therefore, the installation of STC ST00830SE does not affect the ability to accomplish the actions required by this AD. The FAA has not changed this AD in this regard.

Request To Require Removal of Certain Software Versions

Alaska Airlines requested that the proposed AD be revised to require removing a particular version of the software or earlier versions, rather than require installing a particular version or later versions. The commenter asserted that Rockwell Collins software versions 9.0 and earlier are the cause of the unsafe condition.

The FAA does not agree with the suggested change to the requirements of this AD. Such a change would require operators who have certain acceptable earlier software to install different software unnecessarily. Paragraph (k) of

this AD specifically prohibits installing Rockwell Collins FCC OPS software versions P1.1, P2.0, P3.0, P8.0, and P9.0. The unsafe conditions identified in AD 2012–21–08 and in this AD only exist with Rockwell Collins software versions P1.1, P2.0, P3.0, P8.0, and P9.0.

Paragraph (k) of the proposed AD had inadvertently referred to software version ''P1.0'' as one of the affected versions that was prohibited for installation. Boeing Alert Service Bulletin 737–22A1211 correctly identifies this affected software version as ''P1.1.'' The FAA has corrected this reference as version ''P1.1'' in paragraph (k) of this AD.

Request To Require Latest Service Information

Boeing requested that the FAA revise the NPRM to refer to Boeing Alert Requirements Bulletin 737–22A1322 RB, Revision 1, dated January 28, 2021, rather than Boeing Alert Requirements Bulletin 737–22A1322 RB, dated November 21, 2018. Boeing noted that Boeing Alert Requirements Bulletin 737–22A1322 RB, Revision 1, dated January 28, 2021, is the most current revision and has the correct FAA-only approval statement for The Boeing Company Model 737–700C airplanes.

The FAA agrees with the request. The changes in Revision 1 are non-substantive and do not affect the requirements as proposed in the NPRM for this AD. Therefore, the FAA has revised this final rule to refer to Boeing Alert Requirements Bulletin 737–22A1322 RB, Revision 1, dated January 28, 2021, as the appropriate source of service information for the newly required software installation. The FAA also has added paragraph (l) of this AD to provide credit for certain actions that were performed before the effective date of this AD using Boeing Alert Requirements Bulletin 737–22A1322 RB, dated November 21, 2018. Subsequent paragraphs have been re-identified accordingly.

Conclusion

The FAA reviewed the relevant data, considered any comments received, and determined that air safety requires adopting this AD as proposed. Except for minor editorial changes, and any other changes described previously, this AD is adopted as proposed in the NPRM. None of the changes will increase the economic burden on any operator.

Related Service Information Under 1 CFR Part 51

The FAA reviewed Boeing Alert Requirements Bulletin 737–22A1322 RB, Revision 1, dated January 28, 2021. The service information describes procedures for installing and testing an updated version of the FCC OPS.

This AD also requires Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010; and Boeing Alert Service Bulletin 737–22A1224, dated May 18, 2012; which the Director of the Federal Register approved for incorporation by reference as of November 27, 2012 (77 FR 64711, October 23, 2012).

This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in **ADDRESSES**.

Costs of Compliance

The FAA estimates that this AD affects 520 airplanes of U.S. registry. The FAA estimates the following costs to comply with this AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Inspection and installation (retained actions from AD 2012–21–08).	3 work-hours × $85 per hour = $255 per inspection.	$0	$255	$52,785 (based on 207 affected airplanes).
Part number inspection (new action).	1 work-hour × $85 per hour = $85	0	85	$44,200.

The FAA estimates the following costs to do any necessary on-condition actions that would be required. The FAA has no way of determining the number of aircraft that might need these on-condition actions:

ON-CONDITION COSTS

Action	Labor cost	Parts cost	Cost per product
Install upgraded software	1 work-hour × $85 per hour = $85	$0	$85

According to the manufacturer, all of the costs of this AD may be covered under warranty, thereby reducing the cost impact on affected operators. The FAA does not control warranty coverage for affected operators. As a result, the FAA has included all costs in this cost estimate.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs, describes in more detail the scope of the Agency's authority.

The FAA is issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: General requirements. Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

This AD will not have federalism implications under Executive Order 13132. This AD will not have 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.

For the reasons discussed above, I certify that this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866,

(2) Will not affect intrastate aviation in Alaska, and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by:

■ a. Removing Airworthiness Directive (AD) 2012–21–08, Amendment 39–17224 (77 FR 64711, October 23, 2012); and

■ b. Adding the following new AD:

2021–18–17 The Boeing Company: Amendment 39–21718; Docket No. FAA–2020–0103; Product Identifier 2019–NM–149–AD.

(a) Effective Date

This airworthiness directive (AD) is effective December 20, 2021.

(b) Affected ADs

This AD replaces AD 2012–21–08, Amendment 39–17224 (77 FR 64711, October 23, 2012) (AD 2012–21–08).

(c) Applicability

This AD applies to all The Boeing Company Model 737–600, –700, –700C, –800, –900, and –900ER series airplanes, certificated in any category.

(d) Subject

Air Transport Association (ATA) of America Code 22, Auto flight.

(e) Unsafe Condition

This AD was prompted by reports that during autopilot coupled instrument landing system (ILS) approaches, the airplane did not capture or track the glideslope correctly. The FAA is issuing this AD to address this condition, which could allow the airplane to descend below the glideslope beam and result in controlled flight into terrain.

(f) Compliance

Comply with this AD within the compliance times specified, unless already done.

(g) Retained Part Numbers Inspection, With Revised Paragraph References and Removed Terminating Action

This paragraph restates the requirements of paragraph (h) of AD 2012–21–08, with revised paragraph references and removed terminating action. For The Boeing Company Model 737–600, –700, –700C, –800, and –900 series airplanes, certificated in any category; delivered with the Rockwell Collins Enhanced Digital Flight Control System (EDFCS), as identified in the variable number table in Section 1.A.1., Effectivity, of Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010, and not defined by the ''Group 1'' description in Section 1.A. of Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010: Within 3 months after November 27, 2012 (the effective date of AD 2012–21–08), inspect to determine the part number of the operational program software (OPS) of the flight control computers (FCCs), in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010, and install the software as required by paragraph (g)(1) of this AD, or verify that the software is installed as specified by paragraph (g)(2) of this AD, as applicable.

(1) For any OPS having a part number identified in table 1 of the Accomplishment Instructions of Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010: Before further flight, do the actions specified in paragraph (g)(1)(i) or (ii), as applicable.

(i) Install software identified in table 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010, in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010.

(ii) Install software identified in table 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 737–22A1224, dated May 18, 2012, in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010.

(2) For any OPS having a part number identified in table 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010; or in table 2 of the Accomplishment Instructions of Boeing Alert Service Bulletin 737–22A1224, dated May 18, 2012: No further action is required by this paragraph.

(h) Retained Optional Software Installation, With Revised Paragraph References

This paragraph restates the requirements of paragraph (i) of AD 2012–21–08, with revised paragraph references. Installing a version of the FCC OPS approved after May 18, 2012 (the issue date of Boeing Alert Service Bulletin 737–22A1224) terminates the requirements of paragraph (g) of this AD, provided that the conditions specified in paragraphs (h)(1) and (2) of this AD are met.

(1) The version of the FCC OPS must be approved by the Manager, Seattle ACO Branch, FAA; the Manager, Boeing Aviation Safety Oversight Office (BASOO), FAA; or The Boeing Company Organization Designation Authorization (ODA). If approved by the ODA, the approval must include the ODA-authorized signature.

(2) The installation must be done in accordance with a method approved by the Manager, Seattle ACO, FAA; the Manager, BASOO, FAA; or The Boeing Company ODA. If approved by the ODA, the approval must include the ODA-authorized signature.

(i) New Requirement of This AD: Inspection

For all airplanes: Within 12 months after the effective date of this AD, inspect to determine the FCC OPS vendor and version installed on FCC A and FCC B. A review of airplane maintenance records is acceptable in lieu of this inspection if the FCC OPS vendor and version can be conclusively determined from that review.

(j) New Requirement of This AD: Software Installation

(1) For airplanes equipped with Rockwell Collins FCCs with FCC OPS version P8.0 or P9.0 software: Within 12 months after the effective date of this AD, do all applicable actions identified in, and in accordance with, the Accomplishment Instructions of Boeing Alert Requirements Bulletin 737–22A1322 RB, Revision 1, dated January 28, 2021.

Note 1 to paragraph (j)(1): Guidance for accomplishing the actions required by paragraph (j)(1) of this AD can be found in Boeing Alert Service Bulletin 737–22A1322, Revision 1, dated January 28, 2021, which is referred to in Boeing Alert Requirements Bulletin 737–22A1322 RB, Revision 1, dated January 28, 2021.

(2) For airplanes not equipped with Rockwell Collins FCCs with FCC OPS version P8.0 or P9.0 software: No further action is required by this paragraph.

(k) New Requirement of This AD: Parts Installation Prohibition

For all airplanes: As of the effective date of this AD, no person may install Rockwell Collins FCC OPS software version P1.1, P2.0, P3.0, P8.0, or P9.0, on any airplane.

(l) Credit for Previous Actions

This paragraph provides credit for the actions specified in paragraph (j) of this AD, if those actions were performed before the effective date of this AD using Boeing Alert Requirements Bulletin 737–22A1322 RB, dated November 21, 2018.

(m) Alternative Methods of Compliance (AMOCs)

(1) The Manager, Seattle ACO Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or local Flight Standards District Office, as appropriate. If sending information directly to the manager of the certification office, send it to the attention of the person identified in paragraph (n)(1) of this AD. Information may be emailed to: *9-ANM-Seattle-ACO-AMOC-Requests@faa.gov.*

(2) Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the local flight standards district office/ certificate holding district office.

(3) An AMOC that provides an acceptable level of safety may be used for any repair, modification, or alteration required by this

AD if it is approved by The Boeing Company ODA that has been authorized by the Manager, Seattle ACO Branch, FAA, to make those findings. To be approved, the repair method, modification deviation, or alteration deviation must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

(n) Related Information

(1) For more information about this AD, contact Michael J. Tucker, Aerospace Engineer, Systems and Equipment Section, FAA, Seattle ACO Branch, 2200 South 216th St., Des Moines, WA 98198; phone and fax: 206–231–3974; email: *michael.j.tucker@faa.gov*.

(2) Service information identified in this AD that is not incorporated by reference is available at the addresses specified in paragraphs (o)(5) and (6) of this AD.

(o) Material Incorporated by Reference

(1) The Director of the Federal Register approved the incorporation by reference (IBR) of the service information listed in this paragraph under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) You must use this service information as applicable to do the actions required by this AD, unless this AD specifies otherwise.

(3) The following service information was approved for IBR on December 20, 2021.

(i) Boeing Alert Requirements Bulletin 737–22A1322 RB, Revision 1, dated January 28, 2021.

(ii) [Reserved]

(4) The following service information was approved for IBR on November 27, 2012 (77 FR 64711, October 23, 2012).

(i) Boeing Alert Service Bulletin 737–22A1211, dated April 13, 2010.

(ii) Boeing Alert Service Bulletin 737–22A1224, dated May 18, 2012.

(5) For service information identified in this AD, contact Boeing Commercial Airplanes, Attention: Contractual & Data Services (C&DS), 2600 Westminster Blvd., MC 110–SK57, Seal Beach, CA 90740–5600; telephone 562–797–1717; internet *https://www.myboeingfleet.com*.

(6) You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195.

(7) You may view this service information that is incorporated by reference at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fr.inspection@nara.gov,* or go to: *https://www.archives.gov/federal-register/cfr/ibr-locations.html.*

Issued on August 30, 2021.

Gaetano A. Sciortino,

Deputy Director for Strategic Initiatives, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2021–24864 Filed 11–12–21; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2021–0547; Project Identifier MCAI–2021–00574–T; Amendment 39–21762; AD 2021–21–02]

RIN 2120–AA64

Airworthiness Directives; Airbus SAS Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The FAA is adopting a new airworthiness directive (AD) for certain Airbus SAS Model A318, A319, A320, A321, A330–200, A330–200 Freighter, A330–300, A330–800, A330–900, A340–200, A340–300, A340–500, A340–600, and A380–800 series airplanes. This AD was prompted by a determination that repetitive disconnection and reconnection of certain parts manufacturer approval (PMA) nickel-cadmium (Ni-Cd) batteries during airplane parking or storage could lead to a reduction in capacity of those batteries. This AD requires replacing certain PMA Ni-Cd batteries with serviceable Ni-Cd batteries, or maintaining the electrical storage capacity of those PMA Ni-Cd batteries during airplane storage or parking. This AD corresponds to a previously proposed AD on type design Ni-Cd batteries with the same unsafe condition on the same model airplanes. The FAA is issuing this AD to address the unsafe condition on these products.

DATES: This AD is effective December 20, 2021.

The Director of the Federal Register approved the incorporation by reference of certain publications listed in this AD as of December 20, 2021.

ADDRESSES: For service information identified in this final rule, contact Airbus SAS, Airworthiness Office—EIAS, Rond-Point Emile Dewoitine No: 2, 31700 Blagnac Cedex, France; telephone +33 5 61 93 36 96; fax +33 5 61 93 44 51; email *account.airworth-eas@airbus.com*; internet *https://www.airbus.com*. You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195. It is also available at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2021–0547.

Examining the AD Docket

You may examine the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2021–0547; or in person at Docket Operations between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this final rule, any comments received, and other information. The address for Docket Operations is U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: Dan Rodina, Aerospace Engineer, Large Aircraft Section, International Validation Branch, FAA, 2200 South 216th St., Des Moines, WA 98198; telephone and fax 206–231–3225; email *dan.rodina@faa.gov*.

SUPPLEMENTARY INFORMATION:

Background

The FAA issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 by adding an AD that would apply to certain Airbus SAS Model A318, A319, A320, A321, A330–200, A330–200 Freighter, A330–300, A330–800, A330–900, A340–200, A340–300, A340–500, A340–600, and A380–800 series airplanes. The NPRM published in the **Federal Register** on July 19, 2021 (86 FR 37936). The NPRM was prompted by a determination that repetitive disconnection and reconnection of certain PMA Ni-Cd batteries during airplane parking or storage could lead to a reduction in capacity of those batteries. In the NPRM, the FAA proposed to require replacing certain PMA Ni-Cd batteries with serviceable Ni-Cd batteries, or maintaining the electrical storage capacity of those PMA Ni-Cd batteries during airplane storage or parking. The NPRM corresponds to a previously proposed AD on type design Ni-Cd batteries with the same unsafe condition on the same model airplanes. The FAA is issuing this AD to address reduced capacity of certain PMA Ni-Cd batteries, which could lead to reduced battery endurance performance and possibly result in failure to supply the minimum essential electrical power during abnormal or emergency conditions.

Discussion of Final Airworthiness Directive

Comments

The FAA received comments from Air Line Pilots Association, International, which supported the NPRM without change.

The FAA received additional comments from two commenters, including American Airlines and United Airlines. The following presents the comments received on the NPRM and the FAA's response to each comment.

Request To Combine Rulemaking

American Airlines and United Airlines stated there is an NPRM, Docket No. FAA–2021–0350 (86 FR 25810, May 11, 2021), for a different AD that addresses an unsafe condition for certain type design Ni-Cd batteries (original equipment manufacturer (OEM) parts) on Airbus airplanes, which corresponds to European Union Aviation Safety Agency (EASA) AD 2020–0274, dated December 10, 2020 (EASA AD 2020–0274). American Airlines and United Airlines noted that this NPRM, Docket No. FAA–2021–0547, addresses that same unsafe condition for PMA Ni-Cd batteries (PMA parts) and has the same required actions. American Airlines requested that the intent of both NPRMs be combined into a single AD to simplify tracking and actions associated with the aforementioned NPRMs. United Airlines questioned why the FAA is planning on issuing two separate ADs.

The FAA does not agree to combine both NPRMs into a single AD. At the time the NPRMs were developed, the FAA separated the rulemaking for OEM parts from the PMA parts since the FAA was informed of implementation issues with the adoption of combined rulemaking (OEM parts and PMA parts) by the foreign civil aviation authorities. Therefore, as an interim action, the FAA has decided to issue separate ADs for the OEM parts and the PMA parts. The FAA is discussing how to address OEM and PMA parts in ADs for future rulemaking. However, in the interest of safety to address the unsafe condition on the PMA parts identified in this AD, the FAA has determined this AD cannot be delayed.

Request for Information on the Work Scope

United Airlines stated that the requirements in paragraphs (g), (h), and (i) of the proposed AD for the PMA parts have more detail than the requirements in NPRM, Docket No. FAA–2021–0350, for the OEM parts. United Airlines asked if there is contrasting work scopes between the OEM parts NPRM and the PMA parts NPRM.

The FAA notes that the work scope is the same in both NPRMs. The OEM parts NPRM (published as AD 2021–20–08, Amendment 39–21746 (86 FR 57025, October 14, 2021)), refers to EASA AD 2020–0274 as the appropriate source of service information. EASA AD 2020–0274 provides the details for the required actions. Paragraphs (g), (h), and (i) of this AD correspond to the Definitions and paragraphs (1) and (2) of EASA AD 2020–0274.

Conclusion

The FAA reviewed the relevant data, considered any comments received, and determined that air safety requires adopting this AD as proposed. Except for minor editorial changes, this AD is adopted as proposed in the NPRM. None of the changes will increase the economic burden on any operator.

Related Service Information Under 1 CFR Part 51

Airbus has issued Alert Operators Transmission—AOT A24L007–20, Rev 00, dated September 23, 2020; Alert Operators Transmission—AOT A24N006–20, Rev 01, dated October 12, 2020; and Alert Operators Transmission—AOT A24R009–20, Rev 00, dated September 23, 2020. This service information describes procedures for maintaining the electrical storage capacity of Ni-Cd batteries during airplane storage or parking. These documents are distinct since they apply to different airplane models. This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in the **ADDRESSES** section.

Costs of Compliance

The FAA estimates that this AD affects up to 1,814 airplanes of U.S. registry. The FAA estimates the following costs to comply with this AD:

ESTIMATED COSTS FOR REQUIRED ACTIONS

Labor cost	Parts cost	Cost per product	Cost on U.S. operators
5 work-hours × $85 per hour = $425	$8,000	$8,425	Up to $15,282,950.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs, describes in more detail the scope of the Agency's authority.

The FAA is issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: General requirements. Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

This AD will not have federalism implications under Executive Order 13132. This AD will not have 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.

For the reasons discussed above, I certify that this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866,

(2) Will not affect intrastate aviation in Alaska, and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by adding the following new airworthiness directive:

2021–21–02 Airbus SAS: Amendment 39–21762; Docket No. FAA–2021–0547; Project Identifier MCAI–2021–00574–T.

(a) Effective Date

This airworthiness directive (AD) is effective December 20, 2021.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Airbus SAS airplanes identified in paragraphs (c)(1) through (7) of this AD, certificated in any category, equipped with any parts manufacturer approval (PMA) part approved for the type design nickel cadmium (Ni-Cd) batteries identified in Figure 1 to paragraph (c) of this AD.

Figure 1 to paragraph (c) – *Ni-Cd battery*

Airplane Type	Part Number
A318, A319, A320 and A321	2758 or 416526
A330 and A340	4059, 405CH or 505CH
A380	505CH2

(1) Model A318–111, –112, –121, and –122 airplanes.

(2) Model A319–111, –112, –113, –114, –115, –131, –132, –133, –151N, –153N, and –171N airplanes.

(3) Model A320–211, –212, –214, –215, –216, –231, –232, –233, –251N, –252N, –253N, –271N, –272N, and –273N airplanes.

(4) Model A321–111, –112, –131, –211, –212, –213, –231, –232, –251N, –251NX, –252N, –252NX, –253N, –253NX, –271N, –271NX, –272N, and –272NX airplanes.

(5) Model A330–201, –202, –203, –223, –223F, –243, –243F, –301, –302, –303, –321, –322, –323, –341, –342, –343, –743L, –841, and –941 airplanes.

(6) Model A340–211, –212, –213, –311, –312, –313, –541, –542, –642, and –643 airplanes.

(7) Model A380–841, –842, and –861 airplanes.

(d) Subject

Air Transport Association (ATA) of America Code 24, Electrical Power.

(e) Unsafe Condition

This AD was prompted by a determination that repetitive disconnection and reconnection of certain PMA Ni-Cd batteries during airplane parking or storage could lead to a reduction in capacity of those batteries. The FAA is issuing this AD to address reduced capacity of certain PMA Ni-Cd batteries, which could lead to reduced battery endurance performance and possibly result in failure to supply the minimum essential electrical power during abnormal or emergency conditions.

(f) Compliance

Comply with this AD within the compliance times specified, unless already done.

(g) Definitions

(1) For the purposes of this AD, a serviceable PMA Ni-Cd battery is defined as a PMA battery approved for a Ni-Cd battery identified in Figure 1 to paragraph (c) of this AD, all serial numbers, which was, prior to installation, fully (re)charged in an approved battery shop at constant current and after (re)charging, was never installed and (re)connected to an airplane which was parked or stored for more than 2 days, except when the disconnection and subsequent connection of the battery has been accomplished using the preservation procedures as defined in the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD. Where the applicable service information refers to Ni-Cd battery part numbers, use those procedures, as applicable, for the PMA batteries that are approved for that part number.

(i) For A318, A319, A320, and A321 airplanes: Airbus Alert Operators Transmission—AOT A24N006–20, Rev 01, dated October 12, 2020.

(ii) For A330 and A340 airplanes: Airbus Alert Operators Transmission—AOT A24L007–20, Rev 00, dated September 23, 2020.

(iii) For A380 airplanes: Airbus Alert Operators Transmission—AOT A24R009–20, Rev 00, dated September 23, 2020.

(2) For the purposes of this AD, a serviceable non-PMA Ni-Cd battery is defined as a type design Ni-Cd battery having a part number identified in Figure 1 to paragraph (c) of this AD, all serial numbers, which was, prior to installation, fully (re)charged in an approved battery shop at constant current and after (re)charging, was never installed and (re)connected to an airplane which was parked or stored for more than 2 days, except when the disconnection and subsequent connection of the battery has been accomplished using the preservation procedures as defined in the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD.

(3) For the purposes of this AD, a reconnection cycle is defined as one instance of disconnection and connection of a battery, installed on an airplane, to the airplane electrical system during parking or storage periods (for A330 and A340 airplanes) or parking periods (for A318, A319, A320, A321 and A380 airplanes) since the last battery charge at constant current in an approved battery shop, as defined in the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD, except when the conditions specified in paragraph (g)(3)(i) or (ii) have been met. Where the applicable service information refers to Ni-Cd battery part numbers, use those procedures, as applicable, for the PMA batteries that are approved for that part number.

(i) The on-wing battery preservation procedures as defined in the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD have been applied.

(ii) The battery has been disconnected, physically removed from the airplane and then subsequently installed and connected following a shop visit as defined in the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD.

(4) For the purposes of this AD: Group 1 airplanes are those which have a PMA part approved for Ni-Cd batteries identified in Figure 1 to paragraph (c) of this AD installed, which has more than 4 reconnection cycles. Group 2 airplanes are those which have a PMA part approved for Ni-Cd batteries identified in Figure 1 to paragraph (c) of this AD installed, which has 4 or less reconnection cycles, or have a serviceable PMA Ni-Cd battery.

(h) Replacement

(1) For Group 1 airplanes: Within the applicable compliance time specified in paragraphs (h)(1)(i) and (ii) of this AD and thereafter before each release to service of an airplane after parking or storage, as applicable, replace each PMA part approved for a Ni-Cd battery identified in Figure 1 to paragraph (c) of this AD with a serviceable PMA Ni-Cd battery or serviceable non-PMA

Ni-Cd battery, in accordance with the instructions of the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD. Where the applicable service information refers to Ni-Cd battery part numbers, use those procedures, as applicable, for the PMA batteries that are approved for that part number. After replacement of a battery with a serviceable PMA Ni-Cd battery, the airplane becomes a Group 2 airplane.

Note 1 to paragraph (h)(1): Airplanes on which a battery is replaced with a serviceable non-PMA Ni-Cd battery are no longer affected by this AD. AD 2021–20–08, Amendment 39–21746 (86 FR 57025, October 14, 2021), provides requirements for serviceable non-PMA Ni-Cd batteries.

Note 2 to paragraph (h)(1): For Group 1 and Group 2 airplanes, guidance on preventing further reduction of the capacity of Ni-Cd batteries can be found in the off-wing or on-wing battery preservation procedures (including battery shop visits, as applicable) detailed in the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD.

(i) For A318, A319, A320 and A321 airplanes: Within 4 months after the effective date of this AD.

(ii) For A330, A340, and A380 airplanes: Within 6 months after the effective date of this AD.

(2) For Group 2 airplanes: A Group 2 airplane on which the preservation procedures, as detailed in the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD, are not accomplished becomes a Group 1 airplane after application of more than 4 reconnection cycles and must comply with paragraph (h)(1) of this AD. A Group 2 airplane on which preservation procedures, as detailed in the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD, continue to be accomplished, remains a Group 2 airplane. Where the applicable service information refers to Ni-Cd battery part numbers, those procedures, as applicable, must be used for the PMA batteries that are approved for that part number.

(i) Preservation

For Group 2 airplanes: As of the effective date of this AD, provided that the preservation procedures (off-wing or on-wing, as applicable) are accomplished on an airplane in accordance with the instructions of the applicable service information specified in paragraphs (g)(1)(i) through (iii) of this AD, no replacements of affected parts in accordance with the requirements of paragraph (h)(1) of this AD are required (anymore) for that airplane. Where the applicable service information refers to Ni-Cd battery part numbers, those procedures, as applicable, must be used for the PMA batteries that are approved for that part number.

(j) No Reporting Requirement

Although the service information specified in paragraphs (g)(1)(i) through (iii) of this AD specifies to submit certain information to the manufacturer, this AD does not include that requirement.

(k) Other FAA AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, Large Aircraft Section, International Validation Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or responsible Flight Standards Office, as appropriate. If sending information directly to the Large Aircraft Section, International Validation Branch, send it to the attention of the person identified in paragraph (l) of this AD. Information may be emailed to: *9-AVS-AIR-730-AMOC@faa.gov*. Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the responsible Flight Standards Office.

(2) *Contacting the Manufacturer:* For any requirement in this AD to obtain instructions from a manufacturer, the instructions must be accomplished using a method approved by the Manager, Large Aircraft Section, International Validation Branch, FAA; or the European Union Aviation Safety Agency (EASA); or Airbus SAS's EASA Design Organization Approval (DOA). If approved by the DOA, the approval must include the DOA-authorized signature.

(3) *Required for Compliance (RC):* Except as required by paragraph (k)(2) of this AD, if any service information contains paragraphs that are labeled as RC, the instructions in RC paragraphs, including subparagraphs under an RC paragraph, must be done to comply with this AD; any paragraphs, including subparagraphs under those paragraphs, that are not identified as RC are recommended. The instructions in paragraphs, including subparagraphs under those paragraphs, not identified as RC may be deviated from using accepted methods in accordance with the operator's maintenance or inspection program without obtaining approval of an AMOC, provided the instructions identified as RC can be done and the airplane can be put back in an airworthy condition. Any substitutions or changes to instructions identified as RC require approval of an AMOC.

(l) Related Information

For more information about this AD, contact Dan Rodina, Aerospace Engineer, Large Aircraft Section, International Validation Branch, FAA, 2200 South 216th St., Des Moines, WA 98198; telephone and fax 206–231–3225; email *dan.rodina@faa.gov*.

(m) Material Incorporated by Reference

(1) The Director of the Federal Register approved the incorporation by reference (IBR) of the service information listed in this paragraph under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) You must use this service information as applicable to do the actions required by this AD, unless the AD specifies otherwise.

(i) Airbus Alert Operators Transmission—AOT A24L007–20, Rev 00, dated September 23, 2020.

(ii) Airbus Alert Operators Transmission—AOT A24N006–20, Rev 01, dated October 12, 2020.

(iii) Airbus Alert Operators Transmission—AOT A24R009–20, Rev 00, dated September 23, 2020.

(3) For service information identified in this AD, contact Airbus SAS, Airworthiness Office—EIAS, Rond-Point Emile Dewoitine No: 2, 31700 Blagnac Cedex, France; telephone +33 5 61 93 36 96; fax +33 5 61 93 44 51; email *account.airworth-eas@airbus.com*; internet *https://www.airbus.com*.

(4) You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195.

(5) You may view this service information that is incorporated by reference at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, *fr.inspection@nara.gov,* or go to: *https://www.archives.gov/federal-register/cfr/ibr-locations.html*.

Issued on September 29, 2021.

Lance T. Gant,

Director, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2021–24508 Filed 11–12–21; 8:45 am]

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

15 CFR Part 922

[Docket No. 211103–0224]

RIN 0648–BI01

Monterey Bay National Marine Sanctuary Regulations

AGENCY: Office of National Marine Sanctuaries (ONMS), National Ocean Service (NOS), National Oceanic and Atmospheric Administration (NOAA), Department of Commerce (DOC).

ACTION: Final rule and notification of availability of a final management plan and final environmental assessment.

SUMMARY: The National Oceanic and Atmospheric Administration (NOAA) issues final regulations, a final management plan, and a final environmental assessment (EA) for Monterey Bay National Marine Sanctuary (MBNMS or sanctuary). The final rule includes modifications to three provisions of the MBNMS regulations, the modification of an appendix to the MBNMS regulations that describes sanctuary zone boundaries, and the addition of one new definition to the MBNMS regulations. A

final EA and finding of no significant impact (FONSI) have been prepared for this action.

DATES: This final rule is effective on December 15, 2021.

ADDRESSES: To obtain a copy of the final management plan, environmental assessment, and FONSI, contact the Management Plan Review Coordinator at Monterey Bay National Marine Sanctuary, Address: 99 Pacific Street, Building 455A, Monterey, CA 93940; phone number (831) 647–4201; or via email at *mbnmsmanagementplan@noaa.gov*. Copies can also be downloaded from the Monterey Bay National Marine Sanctuary website at *https://montereybay.noaa.gov*.

FOR FURTHER INFORMATION CONTACT: Lisa Wooninck, Monterey Bay National Marine Sanctuary Acting Superintendent, at *lisa.wooninck@noaa.gov* or (831) 647–4201.

SUPPLEMENTARY INFORMATION:

I. Background

A. Introduction

NOAA's Office of National Marine Sanctuaries (ONMS) serves as the trustee for a network of underwater parks encompassing more than 600,000 square miles of marine and Great Lakes waters from Washington State to the Florida Keys, and from Lake Huron to American Samoa. The network includes a system of 15 national marine sanctuaries and two marine national monuments.

B. Monterey Bay National Marine Sanctuary

NOAA established Monterey Bay National Marine Sanctuary in 1992 for the purposes of protecting and managing the conservation, ecological, recreational, research, educational, historical, and aesthetic resources and qualities of the area, including the submarine Monterey Canyon and, subsequently, Davidson Seamount. The sanctuary is located offshore of California's central coast, encompassing a shoreline length of approximately 276 miles between Rocky Point (Marin County) and Cambria (San Luis Obispo County). With the inclusion of the Davidson Seamount Management Zone (DSMZ) in 2008, the sanctuary now spans approximately 6,094 square miles (4,602 square nautical miles (nmi^2)) of ocean and coastal waters, and the submerged lands thereunder, extending an average distance of 30 miles (26 nautical miles (nmi)) from shore. Supporting some of the world's most diverse and productive marine ecosystems, the sanctuary is home to numerous mammals, seabirds, fishes, invertebrates, sea turtles and plants.

C. Need for Action

The primary purpose of the action is to fulfill section 304(e) of the National Marine Sanctuaries Act (16 U.S.C. 1431 *et seq.*) (NMSA). Section 304(e) (16 U.S.C. 1434(e)) requires periodic review of sanctuary management plans to ensure that site-specific management techniques and strategies effectively address changing environmental conditions and threats to protected resources and qualities of the sanctuaries, and that they fulfill the purposes and policies of the NMSA. The management plan review process also includes an assessment of existing sanctuary regulations to determine if any regulatory changes are needed to support management plan objectives.

Accordingly, ONMS conducted a review of the MBNMS management plan and regulations, which resulted in the development of a new management plan for the sanctuary and changes to the sanctuary's regulations.

With this final rule, NOAA modifies three provisions of the MBNMS regulations, modifies appendix E to the MBNMS regulations, and adds one new definition to the MBNMS regulations. These changes support more efficient and effective program management and enhanced stewardship of the sanctuary's natural resources. The need for each regulatory action is described in greater detail in Section III below.

D. Process

The process for this action included four major stages: (1) Information collection and characterization via development and issuance of a sanctuary condition report that describes the status and trends of driving forces and pressures on the ecosystem and natural and archaeological resource conditions in MBNMS, as well as public scoping to further identify issues associated with revising the management plan (scoping was completed on October 30, 2015); (2) preparation and release of a proposed rule (85 FR 40143, July 6, 2020), draft revised management plan, and draft EA in accordance with the National Environmental Policy Act (NEPA); (3) public review and comment on the proposed rule, draft management plan, and draft EA; and (4) preparation and release of a final rule, final management plan, final EA, and FONSI. With the publication of this final rule, NOAA completes the fourth phase of the process. All written comments NOAA received are available at *https://www.regulations.gov/docket/NOAA-NOS-2020-0094*. NOAA's responses to public comments are included in Appendix A of the final EA, and the comments pertaining to this rulemaking are included in Section IV of this document.

Together with this final rule, NOAA is releasing the final management plan, as well as a final EA and FONSI. The management plan describes strategies and action plans for conservation and management of the sanctuary. The EA contains more detailed information on the considerations of the final management plan and regulatory amendments, including an assessment of alternatives, analysis of environmental impacts, and references. The management plan, EA, and FONSI can be found on the website listed in the **ADDRESSES** section above.

II. Changes From Proposed to Final Regulations

After considering the public comments received between July 6 and September 4, 2020, and engaging in interagency consultations and internal deliberations, NOAA revised the proposed beneficial use definition in 15 CFR 922.131 to modify the standard applicable to dredged material eligible for beneficial use in the sanctuary and to clarify that beneficial use includes habitat protection and restoration purposes (changes described in detail below). NOAA made corresponding changes to the final EA and management plan. Additionally, NOAA made technical changes to the descriptions and coordinates of the Motorized Personal Watercraft (MPWC) Zones and access routes within the sanctuary in appendix E to subpart M of part 922. All other regulatory modifications NOAA outlined in the proposed rule remain the same in the final rule.

In the proposed rule, NOAA proposed a definition of ''beneficial use of dredged material'' to mean the use of dredged material removed from any of the four public harbors immediately adjacent to the shoreward boundary of the sanctuary (Pillar Point, Santa Cruz, Moss Landing, and Monterey) that has been determined by the Director to be clean (as defined by 15 CFR 922.131) and suitable (as consistent with regulatory agency reviews and approvals applicable to the proposed beneficial use) as a resource for habitat restoration purposes only. NOAA also proposed the clarification that the beneficial use of dredged material is not disposal of dredged material. With this final rule, NOAA finalizes the definition of ''beneficial use of dredged material'' to mean the use of dredged material

removed from any of the four public harbors adjacent to the sanctuary (Pillar Point, Santa Cruz, Moss Landing, and Monterey) that has been determined by the Director to be suitable as a resource for habitat protection or restoration purposes only. NOAA also finalizes the clarification that the beneficial use of dredged material is not disposal of dredged material.

NOAA made changes to the definition in response to two primary concerns raised during the public comment period. First, several commenters expressed concern that the prescribed use of dredged material for habitat restoration was too restrictive and precluded the use of such material for more proactive shoreline protection projects, such as: Protecting habitat for wildlife; softscape erosion control alternatives; shoreline stabilization; and adaptive management to address impacts from sea level rise. NOAA acknowledges that the term ''restoration'' alone does not adequately encompass proactive measures to protect habitat that may prevent the need for restoration by helping to prevent future habitat degradation. For example, placing sediment on an eroding beach can help protect it from further erosion, and it can contribute to the coastal sediment transport system, which provides sediment to other nearby coastal beaches. Nourishing beaches also helps protect coastal dunes, which provide habitat for threatened and endangered species, such as western snowy plovers. NOAA also recognizes that there may be ancillary benefits from these projects, such as the protection of coastal infrastructure. The purpose of the beneficial use regulatory provisions is to protect and restore sanctuary habitats, such as beaches, through the beneficial use of dredged material. Therefore, NOAA replaces the term ''restoration'' with ''protection or restoration'' to allow the beneficial use of suitable dredged material removed from any of the four local harbors to cover protecting and restoring MBNMS habitats.

Second, commenters expressed concern that the standard NOAA proposed in the definition of ''beneficial use of dredged material'' for sediment to be ''clean'' would be a prohibitively strict threshold because, based on other definitions in the MBNMS regulations, it would mean that the sediment used for habitat protection or restoration projects could contain no detectable levels of any of the substances listed pursuant to section 42 U.S.C. 9601(14) of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) at 40 CFR 302.4.[1] Commenters were concerned that if this standard were applied, it would be more restrictive than those used by other Federal agencies that utilize dredged materials for similar projects, such as the U.S. Army Corps of Engineers (USACE) and the Environmental Protection Agency (EPA). Commenters also expressed concern that it would be very difficult to find sediment that could meet the proposed standard, which would effectively prevent the placement of any dredged sediment and make implementation of the regulation impracticable.

After reviewing public comments, conferring with other agencies, and conducting internal deliberations, NOAA determined that the proposed use of ''clean'' as a standard created challenges, given that word's meaning elsewhere in MBNMS definitions. Upon consideration, NOAA concurs with the concerns outlined above that were raised during the public comment period. Moreover, NOAA has determined that the purpose of protection of sanctuary resources and qualities can be maintained via a revised sediment standard and through the implementation of permit and/or authorization review criteria. Therefore, with this final rule, NOAA revises the standard so that the ONMS Director must determine that the dredged material is ''suitable'' as a resource for habitat protection or restoration purposes only.

NOAA also removed the parenthetical language in the proposed rule following ''suitable'' (*i.e.,* ''as consistent with the regulatory agency reviews and approvals applicable to the proposed beneficial use'') to clarify that the ONMS Director's ''suitable'' determination is not limited to only considering regulatory agency reviews and approvals, although these reviews and approvals will continue to be required. The revised standard fulfills the same purposes and policies of the originally proposed ''clean'' and ''suitable'' standard by ensuring that dredged sediment for proposed habitat protection or restoration projects is subject to rigorous evaluation and furthers the statutory and regulatory purpose of protection of sanctuary resources. The beneficial use of dredged material within MBNMS for habitat protection or restoration purposes still has to meet NOAA's own permitting and/or authorization criteria and undergo environmental review, as well as other rigorous testing and screening criteria established by other Federal and state regulatory agencies, as applicable.

Additionally, NOAA has made technical changes to the descriptions of the harbors in the definition of ''beneficial use of dredged material,'' as well as to the descriptions and coordinates of the Motorized Personal Watercraft (MPWC) Zones and access routes within the sanctuary in appendix E to subpart M of part 922. These technical changes include: Revising the phrase ''removed from any of the four public harbors immediately adjacent to the shoreward boundary of the sanctuary (Pillar Point, Santa Cruz, Moss Landing, and Monterey)'' to ''removed from any of the four public harbors adjacent to the sanctuary (Pillar Point, Santa Cruz, Moss Landing, and Monterey)''; adding the missing phrase ''[Coordinates listed in this appendix are unprojected (Geographic) and based on the North American Datum of 1983]'' to the beginning of appendix E to clarify which projection NOAA uses to calculate the zone coordinates; adding the last point coordinates to each of the five zones to complete the polygon, along with descriptive text explaining how to draw the polygons from point to point; and correcting the magnetic bearings listed for each zone to make them more accurate. These technical changes in the final rule do not result in differences in the list of eligible harbor sources or locations of the polygons from the proposed rule.

NOAA determined that the changes made from proposed to final rule did not result in any changes in the conclusions of the final EA with regard to the significance of the impacts.

III. Summary of Final Regulations

A. Beneficial Use of Suitable Dredged Material

The MBNMS terms of designation and regulations prohibit permitting the disposal of dredged material within the sanctuary other than at sites authorized by the EPA prior to the effective date of designation.[2] NOAA is adding a new definition for ''beneficial use of dredged material'' to 15 CFR 922.131 and amending 15 CFR 922.132(f) to clarify

[1] *See* 15 CFR 922.131 (MBNMS regulation defining ''clean'' as ''not containing detectable levels of harmful matter'' and defining ''harmful matter'' as any substance, or combination of substances, that because of its quantity, concentration, or physical, chemical, or infectious characteristics may pose a present or potential threat to Sanctuary resources or qualities, including but not limited to: Fishing nets, fishing line, hooks, fuel, oil, and those contaminants (regardless of quantity) listed pursuant to 42 U.S.C. 9601(14) of the Comprehensive Environmental Response, Compensation, and Liability Act at 40 CFR 302.4).

[2] Article V of the Monterey Bay National Marine Sanctuary Terms of Designation, 73 FR 70488 (Nov. 20, 2008); 15 CFR 922.132(f).

that ''beneficial use'' of dredged material as defined in 15 CFR 922.131 is not ''disposal'' of dredged material as described at 15 CFR 922.132(a)(2)(i)(F) and 15 CFR 922.132(f). Together, these regulatory changes clarify that the MBNMS terms of designation and regulations do not preclude NOAA from approving the beneficial use of dredged material within sanctuary boundaries that has been removed from any of the four public harbors adjacent to the sanctuary and that has been determined by the Director to be suitable for habitat protection or restoration purposes. In this section, NOAA discusses the requirements to approve beneficial use projects; provides additional historical context for this regulatory clarification in light of the original terms of designation and management approaches; summarizes additional options for sediment placement for habitat protection and restoration purposes that are currently available and remain unchanged by this rulemaking; and provides a brief overview of the regulatory context of dredge, fill, and disposal projects that helped inform this rulemaking.

1. Review and Permitting of Beneficial Use Projects

This section provides additional context on the review criteria and other requirements that must be met for beneficial use projects to be approved.

Any project that proposes the beneficial use of dredged material would require a NOAA sanctuary permit and/or authorization, as well as appropriate review under NEPA, the Clean Water Act, and other applicable statutes. The ONMS Director has broad authority in applying permit review criteria to ensure the proposed project is conducted in a manner that is compatible with the primary objective of protecting sanctuary resources and qualities; to consider other permit review factors deemed appropriate; and to include any permit terms or conditions deemed appropriate.[3] The ONMS Director also has broad authority in applying authorization reviews of any valid lease, permit, license, or approval to include any terms or conditions deemed reasonably necessary to protect sanctuary resources and qualities.[4] The Director would also assess the suitability of the sediment using water quality and sediment quality criteria that are established and updated by the sanctuary to ensure that it matches the physical properties of native sediments at any planned receiving site (*e.g.,* grain size, sediment type) and meets sanctuary water quality objectives.

A proposed project involving the use of dredged material would only be eligible for approval by NOAA if the project demonstrates a sanctuary habitat protection or restoration purpose under the new definition of ''beneficial use of dredged material'' at 15 CFR 922.131. For the purposes of the ''beneficial use of dredged material'' definition in this final rule, ''habitat restoration'' means placing sediment for the purpose of re-establishing natural habitats that have been negatively impacted by erosion processes, including but not limited to wetlands, sandy beaches, and coastal dune habitats. For the purposes of the ''beneficial use of dredged material'' definition in this final rule, ''habitat protection'' means placing sediment at sites in the sanctuary to protect against habitat degradation and reduce the need for future habitat restoration. As an example of how habitat protection may proactively reduce the need for future habitat restoration, a well-designed project could help minimize coastal erosion by providing a buffer of protection during seasonally dynamic storm cycles that could otherwise remove or replace large volumes of sand. Furthermore, when a coastal beach habitat is restored or protected, the adjacent upland resources such as shoreline infrastructure may also be protected.

In addition to a sanctuary permit and/or authorization and an appropriate environmental review, the beneficial use of dredged material at sites within the sanctuary may also require review and permitting by other Federal and State regulatory authorities with jurisdiction over the proposed beneficial use project.

2. Sources of Sediment Eligible for Use in Beneficial Use Projects

This section explains the historical context of the prohibition in the MBNMS terms of designation and regulations on permitting disposal of harbor dredged materials. This section also explains the sources of sediment that are eligible for use in permitted beneficial use projects in the sanctuary: Suitable sediment from local harbors immediately adjacent to the sanctuary; suitable sediment from upland and onshore sources; and suitable sediment from non-harbor offshore sources within the sanctuary.

a. Historical Context of the MBNMS Terms of Designation and Regulations

A key provision of the terms of designation and regulations governing MBNMS stipulates that in no event may sanctuary managers permit, authorize, or approve the disposal of dredged material within the sanctuary other than at federally approved dredge disposal sites established prior to sanctuary designation.[5] Absent clarification in MBNMS regulations that ''disposal of dredged material'' is a different activity than ''beneficial use of dredged material'' for habitat protection or restoration, NOAA has not authorized discharges of harbor-dredged material directly into the sanctuary under its discretionary authority described at 15 CFR 922.48, 922.49, 922.132(e), and 922.133 other than at pre-approved disposal sites.

However, in the last MBNMS Management Plan (November 2008), NOAA stated, ''[i]f investigations indicate that employment of additional beach nourishment sites using clean dredged harbor material would be possible and appropriate, MBNMS may examine whether revision of MBNMS regulations and Designation Document may be warranted; or if a beneficial program might occur via MBNMS permit or authorization in concert with other agencies.''[6]

NOAA has determined that the protection and restoration purposes of local harbor-driven beach nourishment projects—projects that have, to date, largely relied on onshore placement of suitable material—can be further promoted by allowing placement of suitable dredged material directly into the sanctuary below the mean high water (MHW) line for habitat protection or restoration purposes. One example site that could benefit from placement of sediment below MHW line, subject to a project proposal and applicable permit and environmental review criteria, is the potential placement of suitable dredged material from Pillar Point Harbor into the shallow subtidal zone of the sanctuary at El Granada/Surfer's Beach (discussed in more detail below). The beneficial use of suitable dredged material for habitat protection or restoration purposes in the sanctuary would provide an additional effective and sustainable option to address sites in the sanctuary where shoreline habitat and resources have been heavily impacted by erosion or no longer exist due to the presence of shoreline structures, coastal armoring, sea level rise, and increased storm activity.

For the reasons explained here and throughout this final rule, NOAA has

[3] 15 CFR 922.133.

[4] 15 CFR 922.49(a)(4) and 922.132(e).

[5] Article V of the MBNMS Terms of Designation, 73 FR 70488 (Nov. 20, 2008); 15 CFR 922.132(f).

[6] Final Management Plan, pg. 96. available at: *https://montereybay.noaa.gov/intro/mp/welcome.html.*

determined that employment of additional habitat protection or restoration projects using suitable dredged material from any of the four adjacent harbors would be possible and appropriate. Accordingly, this final rule clarifies that beneficial use projects may occur through MBNMS permits and/or authorizations if all applicable criteria are met.

b. Sediment From Local Harbors Immediately Adjacent to the Sanctuary

The four harbors immediately adjacent to the sanctuary, and no other harbors, are considered eligible sources of material for protecting or restoring habitats for several reasons.[7]

First, the four harbors and the sanctuary are in the same local sediment transport cell, which means that the sediments that settle in the four harbor channels generally come from the same sources as those that settle in the sanctuary. Second, if the four harbors adjacent to the sanctuary did not exist, sand and other sediment would not settle in the harbors and would thus remain in the coastal transport cell. Therefore, the regulatory clarifications regarding the permitted use of suitable dredged material from the four named harbors for beneficial use projects achieve the intent of helping restore the normal transport of sediment along the coast within the sanctuary.

Third, the original terms of designation and regulations for MBNMS regarding dredge disposal contemplated the need to accommodate dredging from the four local harbors via disposal of such dredged material at authorized, offshore disposal sites, but they never envisioned the sanctuary as a site to absorb dredge materials from harbors distant to the sanctuary. In fact, NOAA's final EIS for the 1992 MBNMS designation discussed how designating the new sanctuary would prevent the creation of new disposal sites within MBNMS's boundaries for dredged material extracted from the harbors within San Francisco Bay, due to the sanctuary's regulatory prohibition on designation and use of any new ocean dredged material disposal sites within the sanctuary.[8]

Therefore, the clarification in this final rule that disposal of dredged material does not include the beneficial use of dredged material is meant to only address material dredged from any of the four harbors immediately adjacent to MBNMS. For these reasons, the new definition for ''beneficial use of dredged material'' applies to material removed from these four local harbors and not to material removed from other harbors.

c. Upland and Onshore Sediment Sources

As explained above, the original prohibition on the disposal of dredged material in the MBNMS terms of designation and regulations addressed a concern with disposal of harbor-dredged material.[9] Onshore or upland sources of sediment, provided they are not sourced from dredging a harbor other than the four adjacent to MBNMS, are treated differently because they are not harbor-dredged material. NOAA received public comments on the proposed rule that expressed confusion as to the effect of the rulemaking on NOAA's ability to permit placement of upland material for beneficial use projects. This rulemaking does not change NOAA's current authority and long-standing approach with respect to permitting placement of upland or onshore sediments within the sanctuary. The placement of suitable material within the sanctuary that originates from onshore sources (*e.g.,* sediment from coastal bluffs/dunes, coastal lagoon sediment traps, coastal highway construction projects, river maintenance) for habitat protection or restoration projects may continue to be allowed through appropriate permits and/or authorizations and environmental review. NOAA has issued permits in the past for placement of these types of materials within the sanctuary, such as south of Año Nuevo and along the Big Sur coast from coastal highway maintenance and repair projects.

d. Offshore Sediment Sources Within the Sanctuary

NOAA also received public comments that expressed confusion about whether beneficial use projects in the sanctuary may rely upon sediment from offshore sources. Similar to proposed beneficial use projects using upland material, NOAA may permit the placement of suitable sediment from offshore sources within the sanctuary for habitat protection and restoration purposes, as long as the sediment is not dredged from a harbor other than one of the four local harbors referenced above. This rulemaking does not alter NOAA's ability to permit such projects and does not preclude a potential permit applicant from requesting to source and dredge material from within MBNMS (*e.g.,* an offshore sand cell) and deposit it nearshore for habitat protection or restoration.

Review of such a proposed project currently, and after this rulemaking, would need to evaluate the environmental impacts of the removal of the offshore material and the impacts of its deposit elsewhere in the sanctuary. In order to approve such a project, NOAA would need to make the necessary findings within the MBNMS permit or authorization review criteria and other applicable regulations. Review and approval by other agencies may also be required.

3. Other Sediment Placement Options

This section provides a brief summary of two available options for sediment placement for beneficial use purposes in which the sediment is placed outside, rather than within, the sanctuary.

a. Onshore Sediment Placement Shoreward of the Sanctuary's Mean High Water Boundary

Placement of sediment above the mean high water (MHW) line (*i.e.,* outside the MBNMS shoreward boundary) immediately adjacent to the sanctuary would not constitute prohibited disposal of dredged material within the sanctuary. To date, NOAA has accommodated requests for such placement of dredged sediment above the MHW line from three of the four adjacent harbors for beach nourishment purposes.

Several examples of such projects are as follows. In 2007, NOAA concurred with other agencies to allow Moss Landing Harbor to place suitable beach nourishment material from harbor dredging on the beach above MHW immediately south of the harbor breakwater, in an area not within the sanctuary. Further, beach replenishment projects currently occur at Del Monte Beach in Monterey and Twin Lakes Beach in Santa Cruz. The City of Monterey has an MBNMS authorization for the annual placement of dredged material from Monterey Harbor onto two EPA-approved locations above MHW at Del Monte Beach. The material meets USACE, EPA, and California Regional Water Quality Control Board water and

[7] The boundaries of these harbor jurisdictions are described in 15 CFR 922.130(a) and 15 CFR part 922, subpart M, appendix A. *See* 15 CFR 922.130(a). Maps of these harbor jurisdictions with harbor exclusion coordinates noted are located here: *https://nmsmontereybay.blob.core.windows.net/montereybay-prod/media/materials/maps/harbor1_lg.jpg.*

[8] Monterey Bay National Marine Sanctuary Final Environmental Impact Statement and Management Plan Vol 1. 1992. Pgs. IV–31 to IV–35. available at: *https://montereybay.noaa.gov/intro/mp/archive/original_eis/partIV_sI.html.*

[9] *See also* Monterey Bay National Marine Sanctuary Final Environmental Impact Statement and Management Plan Vol 1. 1992, pg. II–79, for additional discussion of dredging and dredge disposal activities in the context of harbor activities. Available at: *https://montereybay.noaa.gov/intro/mp/archive/original_eis/partII_sIII.html#d.*

sediment quality standards and consists primarily of an acceptable grain size that is compatible with the receiving beach. Sediment deposited at these two beach locations in Monterey is eventually washed by natural wave action into lower tidal areas (*i.e.,* below MHW and thus inside the sanctuary) and laterally along the shoreline, effectively maintaining or creating improved coastal habitat and recreational resources within the sanctuary. A similar but larger on-shore beach restoration protocol has been established at Twin Lakes Beach in Santa Cruz for suitable sediment dredged from the entrance channel to Santa Cruz Harbor.

Based upon the past successful use of suitable dredged material for beach nourishment at Santa Cruz, Moss Landing, and Monterey, in 2015 NOAA wrote to Pillar Point Harbor to convey how onshore placement of its suitable dredge material would not constitute discharge within the bounds of the sanctuary and could allow the harbor district to implement a beach nourishment project it had long sought for El Granada/Surfer's Beach next to that harbor. Due to the interruption of natural sand transport patterns, the beach has eroded to such a degree that ocean waters now extend to the toe of the riprap armoring that safeguards Highway 1. El Granada/Surfer's Beach is now often submerged at MHW, and a fraction of the former beach appears only at the lowest tide levels. An on-shore beach restoration project could restore the natural coastal beach habitat, as well as provide recreational benefits to beach goers and protect the highway infrastructure. Pillar Point Harbor has received grant funds and continues to study such an on-shore beach restoration project.

The habitat restoration projects described here have proven successful in maintaining the integrity of high public use beaches that would otherwise suffer from accelerated erosion due to human interruptions of natural sediment transport patterns in the area. Placement of dredged material on these beaches has helped protect coastal beaches and dunes, stabilize their geologic profiles, and protect these habitats for wildlife. Although NOAA has determined that the protection and restoration purposes of local harbor-driven beach nourishment projects can be further promoted by allowing placement of suitable harbor-dredged material directly into the sanctuary, the option of a project using onshore placement of suitable material remains available.

b. Sediment Placement in Areas Outside the Sanctuary

This rulemaking does not affect the current prohibitions on deposition in the sanctuary of any material dredged from harbors other than the four adjacent to the sanctuary, such as the complex of harbors in San Francisco Bay or the San Francisco main ship channel, except for use of federally-approved disposal sites SF–12 and SF–14 off Moss Landing. Nonetheless, Federal and State agencies and harbor managers could discharge suitable material from these sources for beach nourishment offshore of or onshore the approximately 12 miles of coastal habitat and beaches off San Francisco, Daly City, and Pacifica that is outside of the boundaries of Monterey Bay National Marine Sanctuary, subject to other applicable review and permitting requirements. Such a beach nourishment project along this stretch of coast would be closer to the dredged source, which would both increase project feasibility and restore the material to the closest location within the littoral coastal transport cell. A beach nourishment project in this area would not be governed by sanctuary regulations unless there was a potential for that material to enter and injure sanctuary resources.

4. Statutory and Regulatory Context of Dredge, Fill, and Disposal Projects

This action, which clarifies NOAA's authority to approve the use of dredged material from the four adjacent public harbor jurisdictions that has been determined by the Director to be suitable as a resource for habitat protection or restoration purposes within the sanctuary, is consistent with the regulatory framework for dredge, fill, and disposal projects as outlined by the Clean Water Act (33 U.S.C. 1251 *et seq.*), the Ocean Dumping Act (33 U.S.C. 1401 *et seq.*), and applicable USACE and EPA regulations. The existing regulatory framework differentiates between the disposal, or discarding, of dredged material and the beneficial use of dredged material, which refers to the purposeful application of material. For example, the ''disposal into ocean waters'' of dredged material is regulated under provisions of the Ocean Dumping Act, whereas discharge of dredged material for fill, including beach nourishment, is regulated under Section 404 of the Clean Water Act.[10] In addition to the ONMS Director's approval, any proposed beneficial use of dredged material project in MBNMS would be subject to applicable permit and regulatory reviews of other Federal and State authorities with jurisdiction over the proposed project.

Finally, this action is also consistent with current State and Federal coastal management practices that favor softscape approaches to restoring and protecting beaches and shorelines over hardscape methods (*e.g.,* riprap, groins and seawalls).[11] The USACE Engineering and Design Manual on Dredging and Dredged Material (July 2015) states, ''Interest in using dredged material as a manageable, beneficial resource, as an alternative to conventional placement practices, has increased.'' [12] The USACE/EPA Beneficial Use Planning Manual states, ''the promotion of beneficial uses continues to require a shift from the common perspective of dredged material as a waste product to one in which this material is viewed as a valuable resource that can provide multiple benefits to society.'' [13] The planning manual further notes that in general, ''clean, coarse-grained sediments (sands) are suitable for a wide variety of beneficial uses.'' [14] Finally, the USACE/EPA Manual on The Role of the Federal Standard in the Beneficial Reuse of Dredged Material indicates, ''a beneficial use option may be selected for a project even if it is not the Federal Standard for that project.'' [15]

NOAA has determined the placement in the sanctuary of local dredged material (removed from any of the four public harbors adjacent to the sanctuary) that has been determined by the Director to be suitable for habitat protection or restoration purposes is appropriate and consistent with the

[10] 33 CFR 336.0.

[11] *See* California Coastal Commission's Sea Level Rise Policy Guidance, available at: *https://documents.coastal.ca.gov/assets/slr/guidance/2018/0_Full_2018AdoptedSLRGuidanceUpdate.pdf.*

[12] EM 1110–2–5025 at page 5–1 (July 31, 2015), available at: *https://www.publications.usace.army.mil/portals/76/publications/engineermanuals/em_1110-2-5025.pdf.*

[13] Identifying, Planning, and Financing Beneficial Use Projects Using Dredged Material at 11 (October 2007, available at: *https://www.epa.gov/sites/production/files/2015-08/documents/identifying_planning_and_financing_beneficial_use_projects.pdf.*

[14] The USACE/EPA Beneficial Use Planning Manual was not applying NOAA's proposed definition of ''clean'' referring to CERCLA. Rather, the Planning Manual considered suitability factors under the Clean Water Act Section 404(b)(1) guidelines, and data on grain size, levels of contamination, salinity, water content, organic content, acidity, levels of nutrients, and engineering properties. *Id.* at 10–11.

[15] EPA842–B–07–002 (October 2007) at 3, available at: *https://www.epa.gov/sites/production/files/2015-08/documents/role_of_the_federal_standard_in_the_beneficial_use_of_dredged_material.pdf.*

existing regulatory framework for dredge, fill, and disposal projects.

5. Conclusion

For the reasons explained here, NOAA is adopting this regulatory change to clarify NOAA's authority to approve the beneficial use of suitable dredged material for habitat protection or restoration purposes within MBNMS. Such use would not constitute ''disposal of dredged material'' within the meaning of the MBNMS terms of designation and regulations. This regulatory change does not pose additional regulatory burdens to the public, but rather, increases the availability of projects that may be permitted to help address coastal erosion and beach nourishment in the sanctuary.

B. Modification of Seasonal/Conditional Requirement for Motorized Personal Watercraft (MPWC) Access to MPWC Zone 5 at Mavericks

Consistent with the text that appeared in the proposed rule, NOAA amends MBNMS regulations to reduce the sea state condition required for MPWC access to MPWC zone 5 at Mavericks, offshore of Half Moon Bay. NOAA is changing the current high surf warning (HSW) requirement to a less stringent high surf advisory (HSA) requirement. The MPWC zone 5 was created in 2009 primarily to allow MPWC to support big-wave surfing at Mavericks during winter months when wildlife activity is significantly reduced in this area. Currently, MPWC may access zone 5 at Mavericks only when HSW conditions (predicted breaking waves at the shoreline of 20 feet or greater) are in effect, as announced by the National Weather Service for San Mateo County during the months of December, January, and February. However, due to unique bathymetric features at Mavericks, waves can exceed 20 feet well before HSW conditions are announced county-wide. Allowing MPWC access to Mavericks during HSA conditions (predicted breaking waves at the shoreline of 15 feet or greater) allows MPWC presence at the break three to five additional days per year to provide safety assistance to surfers operating in a highly energized surf zone.

Surfers have developed new techniques for accessing larger waves, enabling surfers to now routinely surf extremely large waves at Mavericks during winter HSA conditions when MPWC access to the zone is currently prohibited. In February 2017, an MBNMS Advisory Council subcommittee recommended lowering the current conditional threshold for MPWC access to Mavericks from a HSW to a HSA condition during the months of December, January, and February to allow expanded use of MPWC for safety assistance to surfers recreating in extreme sea conditions. The MBNMS Advisory Council voted unanimously to support the subcommittee recommendation on February 17, 2017. NOAA agrees with the MBNMS Advisory Council recommendation and believes it would benefit public safety, while posing no significant added threat of disturbance to protected wildlife due to minimal wildlife activity in the area during extreme high-surf conditions in winter months.

C. Reconfiguration of Year-Round MPWC Zone Boundaries

Consistent with the text that appeared in the proposed rule, NOAA amends the MBNMS regulations to modify boundaries of four, year-round MPWC zones in a manner that maintains NOAA's original intent to provide recreational opportunities for MPWC within the sanctuary, while safeguarding sensitive sanctuary resources and habitats from unique threats of disturbance by these watercraft. NOAA is not modifying the boundaries of the seasonal/conditional zone 5 at Mavericks.

Specifically, these modifications reduce the number of deployed boundary buoys and associated navigational hazards, aesthetic impacts, and mooring failures that create public safety issues, marine debris, seafloor impacts, and excessive maintenance efforts. The zones were established in 1992 to provide recreational use areas for MPWC while safeguarding marine wildlife and habitats. MPWC have the unique capability to sharply maneuver at high speeds in the ocean environment and freely access remote and sensitive marine habitat areas, unlike any other type of motorized vessel (57 FR 43310, September 18, 1992).

The four MPWC zones were established near each of the four harbors in the sanctuary where MPWC operators typically launch. The boundaries were delineated without consideration of practical matters such as the integrity or sustainability of buoy stations. For example, buoys deployed off rocky points have experienced repeated mooring failures due to heavy wave diffraction/reflection, abrasive and mobile rocky substrate affecting mooring tackle, and a lack of soft sediments into which an anchor may be securely set. Buoys deployed in deep water have repeatedly failed due to suspected interactions with vessels and commercial fishing gear. Mooring failures cause deposition of chain and anchors on the seafloor and pose a hazard to mariners and the public from drifting buoys. Even when buoys hold station, they could present navigation obstacles. As stated above, reducing the number of boundary buoys by utilizing existing marks and geographical features (*e.g.,* United States Coast Guard (USCG) navigation buoys and landmarks) can markedly reduce navigational hazards and mooring failures that create public safety issues, marine debris, seafloor impacts, and excessive maintenance efforts.

Anecdotal observations of MPWC zone use over time by harbor officials, marine enforcement officers, ocean users, sanctuary staff, and volunteers indicate that the zones are rarely used by MPWC operators. Therefore, reconfiguring the zones will minimally impact a small number of users.

Relocation of marker buoys to shallower mooring depths will improve station-keeping, inspection, and maintenance of buoy moorings. Reconfiguring the four zones reduces the overall number of deployed MPWC boundary buoys from fifteen to nine, which is a 40% net reduction in the number of MPWC boundary buoy mooring sites; eliminates six existing buoy mooring stations entirely; replaces four existing mooring stations with four new shallower mooring stations; and leaves five previous mooring stations unchanged. These modifications will result in the permanent removal of anchors and chain from the seafloor at ten sites and the installation of anchors and chain at four new sites. As previously stated, the four new mooring stations will be in shallower water and deliberately sited in mud/sand substrate to avoid rocky reef habitat—a purposeful reduction of negative environmental impacts. Zone reconfigurations result in a 59% reduction of total areal coverage of the four year-round zones, resulting in an equal reduction of surface area subject to direct MPWC interactions with specially protected marine wildlife, such as migratory birds, whales, dolphins, porpoise, turtles, sea lions, and sea otters.

The reconfigured MPWC zones still provide considerable area adjacent to all four harbors for general use of MPWC, fulfilling the original goal for the zones when MBNMS was established in 1992. The four reconfigured year-round access zones offer 0.96 square miles (0.72 nmi^2) of riding area south of Pillar Point Harbor, 2.63 square miles (1.99 nmi^2) off Santa Cruz Harbor, 2.29 square miles (1.73 nmi^2) off Moss Landing Harbor,

and 3.10 square miles (2.34 nmi^2) off Monterey Harbor. Maps depicting MPWC zone boundary changes can be found in the final EA.

Reconfiguring the four zones to be smaller and closer to shore provides improved MPWC access and operator safety, and also aids zone monitoring, enforcement, and planned systematic surveys of zone use described in the new MBNMS management plan. The zone reconfigurations shorten the length of the MPWC access corridors to the Santa Cruz and Monterey zones by 66% and 23% respectively, allowing MPWC operators easier and quicker access to both riding zones. The shorter access corridors lower the potential for negative interactions with marine traffic and wildlife as MPWC transit to or from harbors. Rotation of the access corridor at the Monterey zone, away from the predominant marine traffic pattern at the harbor entrance, also reduces the potential for negative interaction with other vessels there. The reconfigured zone boundaries at Santa Cruz shift that zone closer to shore, which provides MPWC operators easier and faster access to the riding area, as well as improved safety should an MPWC operator need emergency assistance. In the past, MPWC users requested that the access corridor be shortened and the zone at Santa Cruz be shifted closer to shore.

The five existing MPWC zones remain at their current general geographical location. Consistent with the proposed rule, NOAA is making the following changes to the four year-round MPWC zones:

1. Modify the year-round MPWC zone at Half Moon Bay by using existing USCG red bell buoy 2 and existing USCG green gong buoy 1S as boundary points instead of current MBNMS buoys PP2 and PP3. By re-shaping the current zone from a parallelogram to a concave pentagon, the zone's general position south of Pillar Point Harbor is maintained, increasing the zone area by 10% (from 0.87 sq mi (0.66 nmi^2) to 0.96 sq mi (0.73 nmi^2)). Permanent removal of the two MBNMS buoys at this zone reduces navigational obstructions, risk of mooring failure, and buoy and tackle loss.

2. Modify the year-round MPWC zone at Santa Cruz by using existing USCG red/white whistle buoy SC as a boundary point, instead of the current MBNMS buoy SC7. By re-shaping the current zone from a rectangle to a parallelogram, the zone position rotates 45° clockwise to the NE, reducing the zone area by 59% (from 6.36 sq mi (4.80 nmi^2) to 2.63 sq mi (1.98 nmi^2)). The transit route to the zone from the entrance of the Santa Cruz Small Craft Harbor is reduced from 1.35 miles (1.17 nmi) to 0.5 miles (0.43 nmi). One MBNMS buoy will be permanently removed from the waterway, one buoy will remain on station, and two buoys will be redeployed to shallower depths. The redistributed buoys will be positioned within better visible range of one another, in softer seafloor sediments, and away from rocky points, thus reducing navigational obstructions, risk of mooring failure, and buoy and tackle loss.

3. Modify the year-round MPWC zone at Moss Landing by eliminating current MBNMS buoys ML4 and ML5. By re-shaping the current zone from an irregular hexagon to a trapezoid, the eastern portion of the zone remains in its current position; the zone area is reduced by 72% (from 8.10 sq mi (6.12 nmi^2) to 2.29 sq mi (1.73 nmi^2)). Permanent removal of two MBNMS buoys at this zone reduces navigational obstructions, risk of deep-water mooring failures, and buoy and tackle loss.

4. Modify the year-round MPWC zone at Monterey by using existing USCG red bell buoy 4 as a boundary point instead of MBNMS buoy MY3. By re-shaping the current zone from a trapezoid to a parallelogram, the zone position rotates 90° clockwise to the NE, and the zone area is reduced by 51% (from 6.36 sq mi (4.8 nmi^2) to 3.10 sq mi (2.34 nmi^2)). One MBNMS buoy will be permanently removed from the waterway, one buoy remains on station, and two buoys will be redeployed to shallower depths. The redistributed buoys will be positioned within better visible range of one another, in softer seafloor sediments, and away from rocky points and popular commercial squid fishing grounds, which reduces navigational obstructions, risk of deep-water mooring failure, risk of disruption to commercial fisheries, and buoy and tackle loss.

The length of the prescribed zone transit route from Monterey Harbor decreases from 1.00 mile (0.87nm) to 0.77 miles (0.67 nm). In addition, the transit corridor rotates 52 degrees farther east from the harbor entrance, away from the predominant marine traffic pattern to and from the harbor.

Reducing the number of necessary MPWC boundary buoys also reduces impacts to benthic habitats, risk of wildlife entanglements, and risk of maritime collisions. Relocating buoys will make them more resistant to storm damage and buoy anchor and chain failure, thereby reducing risks to mariners from drifting buoys and marine debris from unnecessary deposition of chain and anchors on the seafloor. Utilizing mooring locations over soft seafloor sediments can reduce scarring and damage to hard-substrate benthic habitat and organisms from mooring chains.

In summary, revising locations of MPWC zone boundaries represents essential adaptive management as envisioned in the NMSA and the required management plan review process. The adjustments maintain 9 square miles (7.82 nmi^2) of the sanctuary for operating MPWC off all four harbors in areas with decreased likelihood of wildlife disturbance, which were goals for the original creation of the zones in 1992. Coupled with the increased operating days at the seasonal/conditional MPWC zone at Mavericks, NOAA's original intent to facilitate MPWC recreational opportunities is maintained. Maps depicting the proposed MPWC zone boundary changes can be found in the final EA.

D. Exempted Department of Defense Activities Within Davidson Seamount Management Zone

Consistent with the text that appeared in the proposed rule, NOAA amends MBNMS regulations by modifying 15 CFR 922.132(c)(1) to correct an error. The current regulatory text at 15 CFR 922.132(c)(1) states, in part, that a list of exempted Department of Defense (DOD) activities at the Davidson Seamount Management Zone (DSMZ) is published in the 2008 Final Environmental Impact Statement (FEIS) that accompanied the 2008 MBNMS Management Plan. However, due to an administrative error, the list of exempted activities was not included in the 2008 FEIS. A December 18, 2006, letter from the U.S. Air Force (USAF) 30th Space Wing identified a list of USAF activities at the DSMZ that existed at the time of the DSMZ designation that are subject to DOD exemption. The MBNMS Superintendent confirmed in a January 5, 2009, letter to the USAF 30th Space Wing that NOAA acknowledged the list of exempted activities as valid from the effective date of inclusion of the DSMZ within MBNMS (March 9, 2009) and that NOAA would correct the administrative record and regulations to properly document the exempted DOD activities within the DSMZ. Accordingly, NOAA amends 15 CFR 922.132(c)(1) by replacing ''2008 Final Environmental Impact Statement'' with ''2021 Final Environmental Assessment for the MBNMS Management Plan Review'' and has added an appendix to the 2021 final EA to serve as the published list of exempted DOD activities within the DSMZ. NOAA herein affirms that the exemptions requested by the USAF in 2006 and

confirmed by NOAA in 2009 have been valid since the effective date of the DSMZ's addition to MBNMS (March 9, 2009).

IV. Response to Comments

NOAA received 159 comments on the proposed rule, draft management plan, and draft environmental assessment (EA) during the July 6 through September 4, 2020, public review period. NOAA hosted three virtual public meetings with 117 total participants. NOAA received written comments from members of the public submitted at *www.regulations.gov,* written comments from MBNMS's Research Activity Panel, and oral and written comments provided during virtual public meetings and two sanctuary advisory council meetings. Due to the volume of comments received, the section below summarizes and addresses those comments related to the proposed rulemaking. Please refer to Appendix A in the final EA (*https://montereybay.noaa.gov/intro/mp/welcome.html*) to see summaries of and responses to all substantive issues raised in all comments for the proposed rule, draft management plan, and draft EA.

All substantive issues raised in relation to the proposed rulemaking are summarized and addressed in this section. NOAA summarized the comments according to the content of the statement or question put forward in written statements or oral testimony regarding the proposed action and alternatives. Technical or editorial comments on any of the draft documents are incorporated in the final rule, final management plan, and final EA, and are not described in further detail here.

Beneficial Use of Dredged Material Regulation

1. Comment: NOAA should support the regulation clarifying the language in the terms of designation and MBNMS regulations prohibiting permitting the disposal of dredged material within the sanctuary (other than at sites authorized by the U.S. EPA prior to the effective date of designation) which does not preclude NOAA from authorizing the beneficial use of clean dredged material within sanctuary boundaries when suitable for habitat restoration purposes.

Response: NOAA agrees and is moving forward with the beneficial use regulation with some clarifications and modifications.

''Clean'' Definition

2. Comment: NOAA should clarify its definition of ''clean'' material and clarify the standards used to assess material appropriate for beneficial use projects.

Response: In this final rule, NOAA acknowledges that the proposed use of ''clean'' as a standard for beneficial use projects created challenges given how that word is defined elsewhere in MBNMS regulations (*see* 15 CFR 922.131). NOAA has determined that the purpose of protection of sanctuary resources and qualities could be maintained via a revised sediment standard and implementation of permit and/or authorization review criteria. NOAA has therefore removed ''clean'' from the sanctuary definition of ''beneficial use of dredged material.'' Instead, the ONMS Director must determine that the dredged material is ''suitable'' as a resource for habitat protection or restoration purposes. Please see Section II. ''Changes from Proposed to Final Regulations'' for further information about the change from the proposed rule to the final rule, as well as a description of the standard for 'suitable'.

Beneficial Use Standards

3. Comment: NOAA should use EPA's standards for determining suitability of dredged material for placement within MBNMS for beneficial use.

Response: NOAA will apply ONMS review criteria for permits and/or authorizations. In addition to an ONMS permit or authorization, a project would also be reviewed and permitted, as appropriate, by other Federal and State regulatory authorities with jurisdiction over the proposed beneficial use project, such as the EPA, as applicable. Please see Section III A. 1. ''Review and permitting of beneficial use projects'' for more information on how NOAA will evaluate beneficial use projects proposed to be conducted within sanctuary boundaries.

Limited Sources of Dredged Material

4. Comment: NOAA received comments that the proposed beneficial use definition unnecessarily limits the origin of dredged material that can be considered for beneficial use to the four harbors adjacent to the sanctuary.

Response: NOAA provides several reasons in Section III. A. 2. b., ''Sediment from local harbors immediately adjacent to the sanctuary,'' why the four harbors immediately adjacent to the sanctuary, and no other harbors, are considered eligible sources of material for protecting or restoring habitats. First, the four harbors and the sanctuary are in the same local sediment transport cell, which means that the sediments that settle in the four harbor channels generally come from the same sources as those that settle in the sanctuary. Second, if the four harbors adjacent to the sanctuary did not exist, sand and other sediment would not settle in the harbors and would thus remain in the coastal transport cell. Therefore, the regulatory clarifications regarding the permitted use of suitable dredged material from the four named harbors for beneficial use projects achieve the intent of helping restore the normal transport of sediment along the coast within the sanctuary. Third, NOAA describes historical reasons why the original designation of MBNMS did not envision the sanctuary as a site to absorb dredge materials from harbors distant to MBNMS.

In addition to the four harbors, NOAA describes several other sources of material that could be approved for beneficial use projects within the sanctuary. Please see Section III. 2. ''Sources of Sediment eligible for use in beneficial use projects'' for more information on other eligible sources of material.

Habitat Protection and Restoration

5. Comment: NOAA received comments that the proposed rule restricts the use of dredged material to ''habitat restoration,'' which could preclude using the dredge material to protect infrastructure threatened by coastal erosion, sea level rise, and coastal storms.

Response: In response to these comments, NOAA has modified the definition of the ''beneficial use of dredged material'' to clarify that beneficial use of dredged material includes habitat protection and habitat restoration purposes. As explained in Section II. ''Changes from Proposed to Final Regulation'' and Section III. A. 1. ''Review and Permitting of Beneficial Use Projects'', proactive ''protection'' of natural habitats serves a beneficial purpose and, by helping to prevent future degradation of habitat, may preclude or reduce the need for habitat restoration. An ancillary benefit from restoring and protecting beach habitat could include coastal infrastructure protection.

6. Comment: NOAA should describe habitat restoration purposes to meet the criteria for beneficial use.

Response: NOAA includes managing sediment for the purpose of habitat restoration in the two Coastal Regional Sediment Management Plans (CRSMP) that pertain to MBNMS. For example, the CRSMP for the Santa Cruz Littoral Cell mentions that sediment management projects could provide several direct benefits to the region

including ''mitigating shoreline erosion and coastal storm damage; allowing for biological habitat restoration and protection; increasing natural sediment supply to the coast; and providing public safety, access and recreational benefits through beach restoration.'' [16] Further, implementation of the two CRSMPs are included in the Coastal Erosion and Sediment Management Action Plan, Strategy CESM–1. NOAA also provides additional information in Section III. A. 1. ''Review and Permitting of Beneficial Use Projects'' regarding the meaning of ''habitat restoration'' for purposes of this final rule.

Authorizations

7. Comment: NOAA should clarify the process for ONMS to issue authorizations to USACE for permits to allow disposal of dredged material in the sanctuary by Santa Cruz Port District (SCPD).

Response: Within MBNMS, NOAA ONMS authorizes permits issued for disposal of dredged material at approved disposal sites. An authorization or permit is necessary for this prohibited activity to be conducted within the sanctuary (15 CFR 922.48, 922.49, 922.132, and 922.133). NOAA may authorize the USACE dredge disposal permit issued to SCPD and/or the California Coastal Commission (CCC) Coastal Development Permit (CDP) based on NOAA's authorization review process, including in this instance, consideration of alignment of regulated activities and mitigations to protect sanctuary resources. In summary, NOAA will continue to work closely with EPA, USACE, CCC, and other State and Federal resource agencies when assessing dredge disposal activities, and may authorize valid permits, leases, licenses, approvals or other authorizations (15 CFR 922.132(e)) pertaining to dredge disposal in approved dredge disposal sites (15 CFR 922.132(a)(2)(i)(F)).

Impact on Current Harbor Dredge Authorization and Permitting Processes

8. Comment: NOAA received comments asking if NOAA's regulatory action regarding beneficial use of dredged material will affect how ONMS authorizes current harbor dredge disposal activities.

Response: NOAA has issued sanctuary authorizations to Santa Cruz, Moss Landing, and Monterey harbors for depositing harbor dredge at approved disposal sites in the past. NOAA's regulatory action regarding beneficial use of dredged material will not alter the sanctuary authorization or permitting process for depositing harbor dredge material at the approved disposal sites (15 CFR 922.132(a)(2)(i)(F)). If any of the four harbors identified in the ''beneficial use'' definition (the three listed here or Pillar Point) propose a project for which the material dredged from their harbor would be used for beneficial use to protect or restore habitat, NOAA would follow the process steps outlined in this rule.

Beach Nourishment

9. Comment: NOAA should reserve the right to alter the timing and frequency of beach nourishment treatments should data and analysis indicate negative ecological impacts from excessive sediment loading or seasonal conflicts with reproductive cycles of flora and fauna.

Response: NOAA concurs. In accordance with 15 CFR 922.49(a)(4) and 15 CFR 922.132(e), authorization applicants must comply with any terms and conditions the issuing NOAA official deems reasonably necessary to protect sanctuary resources and qualities. This may include terms and conditions pertaining to the timing and frequency of dredged material placement.

10. Comment: NOAA should consider authorizing use of contaminated dredge materials for beneficial use if pre-treated to reduce toxicity levels.

Response: NOAA believes it is important for MBNMS to only rely upon dredged material that has been deemed suitable by the ONMS Director for habitat protection or restoration projects. As explained in Section III. A. 1. ''Review and Permitting of Beneficial Use Projects'', the determination of suitability includes consideration of compatibility standards for water and physical quality of any sediment placed within the sanctuary to ensure protection of native habitats and ecology. If dredged material can be successfully pre-treated to reduce toxicity to suitable levels, it may be considered for beneficial use projects.

11. Comment: NOAA should consider negative effects of beach nourishment, such as introduction of invasive species and interruption of important temporal ecological processes at receiving sites.

Response: NOAA concurs and has implemented regulations that prohibit the introduction of introduced species to the ecosystem of the sanctuary (15 CFR 922.131 and 922.132(a)(12)). Ecological impacts to receiving sites will be assessed through project-specific environmental reviews, including assessments of the source sediment to ensure the absence of introduced species. Further, NOAA will consult with appropriate resource management agencies for any proposed beach nourishment project in the sanctuary using beneficial use of dredge material.

Artificial Reefs, Islands, and Other Purposes

12. Comment: NOAA should authorize use of dredged material for artificial reefs, islands, and other purposes beyond habitat restoration.

Response: NOAA disagrees. Using dredged material to develop artificial reefs and islands within MBNMS is beyond the scope of this action and the intent of the original sanctuary designation. NOAA is implementing this action to protect and restore natural habitats and ecological communities and processes within sanctuaries as much as possible—not to create artificial habitats and communities for interests or development purposes that may be incompatible with the sanctuary's primary mandate of resource protection. Furthermore, the State is the lead authority for artificial reefs in California state waters and does not have a process in place for permitting artificial reefs at this time.

13. Comment: NOAA should use crushed glass for clean fill material for artificial reefs.

Response: NOAA disagrees. There are strict prohibitions regarding ocean dumping and discharges into the sanctuary and this suggestion runs counter to these prohibitions. See, as well, the response to the above comment regarding artificial reefs.

List of Department of Defense Exempted Activities

14. Comment: NOAA should rectify the omission of the list of exempted Department of Defense Activities at the Davidson Seamount Management Zone in the 2008 FEIS.

Response: NOAA is including an appendix in the 2021 final EA to serve as the published list of exempted DOD activities within the DSMZ, which is referenced and confirmed by the January 5, 2009, letter to the U.S. Air Force 30th Space Wing from the MBNMS Superintendent.

Cruise Ships and Discharges

15. Comment: NOAA should ban cruise ships in the sanctuary as well as any discharges of fuel and waste from them.

[16] Coastal Regional Sediment Management Plan for the Santa Cruz Littoral Cell, Pillar Point to Moss Landing. September 2015. Pg. 217. Available at: *https://montereybay.noaa.gov/resourcepro/resmanissues/crsmp-sc.html.*

Response: The NMSA facilitates multiple uses within sanctuaries, including commercial and recreational uses, compatible with the primary objective of resource protection. NOAA believes the current MBNMS regulations prohibiting discharges from within or into MBNMS of any material or other matter from a cruise ship (*e.g.,* fuel and waste), except clean vessel engine cooling water, clean vessel generator cooling water, vessel engine or generator exhaust, clean bilge water, or anchor wash (15 CFR 922.132(a)(2)(ii)), are adequate at this time to protect sanctuary resources while also allowing use of the resources from a cruise ship. If data become available in the future that show that these regulations are not adequate, NOAA can amend regulations affecting cruise ships in the future.

Opposition to MPWCs, Closure of Pillar Point Zone

16. Comment: NOAA received a variety of comments regarding MPWCs, including recommendations to prohibit MPWC operation throughout MBNMS; close the year-round MPWC operating zone at Pillar Point due to low use by MPWC; prohibit MPWC operations in nearshore areas; and implement NOAA's planned assessment of MPWC zone use.

Response: NOAA is not closing any of the five existing zones where MPWC are allowed to operate within the sanctuary. However, Strategy RP–15 in the final management plan includes assessing MPWC use levels and impacts within the MPWC zones, as well as an evaluation of the relevance of the zones in meeting their originally intended purposes. The MPWC zones were originally sited seaward of nearshore resources such as kelp forests and rocky reefs to minimize negative impacts to coastal wildlife and habitats. Thus, MPWC are already excluded from nearshore areas of the sanctuary, except as permitted by NOAA or approved for public safety agency training and search and rescue operations.

Sanctuary Ecologically Significant Areas (SESAs)

17. Comment: NOAA should not make Sanctuary Ecologically Significant Areas (SESAs) into regulated marine protected areas.

Response: NOAA is not planning to implement additional regulated zones in the sanctuary. SESAs are areas that encompass remarkable, representative, and/or sensitive marine habitats, communities and ecological processes. SESAs are focal areas for facilitating research with partners in order to better understand natural and human-caused variation, as well as resource protection.

V. Classification

A. National Environmental Policy Act

In accordance with NEPA, on August 27, 2015, NOAA published a notice of intent to prepare an Environmental Impact Statement (EIS) in order to identify and analyze potential impacts associated with a review of the 2008 management plan for MBNMS (80 FR 51973). NOAA's analysis of the draft management plan and proposed regulatory changes indicated no significant impacts are expected. Accordingly, NOAA determined the preparation of an EIS would not be necessary, and instead prepared a draft EA, which was made available for public review on July 6, 2020 (85 FR 40143). In that notice, NOAA also withdrew the portion of the **Federal Register** Notice published on August 27, 2015, that provided notice of intent to prepare an EIS.

In the draft EA, NOAA evaluated the potential impacts on the human environment of the proposed action and alternatives in compliance with NEPA, as amended (42 U.S.C. 4321 *et seq.*), and its implementing regulations (40 CFR parts 1500 through 1508). NOAA prepared the EA and FONSI for this action using the 1978 Council on Environmental Quality (CEQ) regulations because this environmental review began before September 14, 2020, which was the effective date of the amendments to the CEQ regulations implementing NEPA (85 FR 43304, July 16, 2020). The draft EA considered all reasonable alternatives to the proposed Federal action that met the purpose and need for the action. These alternatives included a no action alternative and a range of reasonable alternatives for managing MBNMS according to the objectives of the NMSA.

The draft EA found that no significant impacts to resources and the human environment are expected to result from this proposed action. Following public comment on the proposed rule and draft EA and consultation under applicable natural and cultural resource statutes (described below), NOAA prepared a final EA and FONSI.

In preparing the final EA, NOAA evaluated and considered all public and agency comments received on the draft EA and notice of proposed rulemaking, which resulted in changes to the proposed regulations and draft management plan. NOAA determined that these changes to the regulations and draft management plan did not result in any changes to the determinations of the draft EA with regard to the significance of the impacts. Therefore, NOAA prepared a FONSI that concluded that implementing Alternative C (*i.e.,* adopt a new management plan and modify MBNMS regulations) would not have a significant impact on the quality of the human environment. Copies of the final EA and FONSI are available at the website listed in the **ADDRESSES** section of this final rule.

B. Executive Order 12866: Regulatory Planning and Review

This rule has been determined to be not significant for purposes of Executive Order 12866.

C. Executive Order 13132: Federalism

NOAA has concluded this regulatory action does not have federalism implications sufficient to warrant preparation of a federalism assessment under Executive Order 13132.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), as amended and codified at 5 U.S.C. 601 *et seq.,* requires an agency to prepare a regulatory flexibility analysis of any rule subject to the notice and comment rulemaking requirements under the Administrative Procedure Act (5 U.S.C. 553) or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.

Under section 605(b) of the RFA, if the head of an agency (or his or her designee) certifies that a rule will not have a significant impact on a substantial number of small entities, the agency is not required to prepare a regulatory flexibility analysis. Pursuant to section 605(b), the Chief Counsel for Regulation, Department of Commerce, submitted a memorandum to the Chief Counsel for Advocacy, Small Business Administration, certifying that the original proposed rule would not have a significant impact on a substantial number of small entities. The rationale for that certification was set forth in the preamble of the proposed rule (85 FR 40143, July 6, 2020).

None of the changes NOAA has made to the regulations from the proposed rule to the final rule alter the determination that this rule will not have a significant impact on small businesses. The impact levels assessed in the original analysis remain valid (*see* table summarizing impact levels, 85 FR 40143, 40150). NOAA also did not receive any comments on the certification or conclusions. Therefore, the determination that this rule will not have a significant economic impact on a substantial number of small entities

remains unchanged. As a result, a final regulatory flexibility analysis was not required and none was prepared.

E. Paperwork Reduction Act

This final rule does not create any new information collection requirement, nor does it revise the information collection requirement that was approved by the Office of Management and Budget (OMB Control Number 0648–0141) under the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* (PRA). Notwithstanding any other provision of the law, no person is required to respond to, nor shall any person be subject to a penalty for failure to comply with, a collection of information subject to the requirements of the PRA, unless that collection of information displays a currently valid OMB Control Number.

F. National Historic Preservation Act

In fulfilling its responsibility under the National Historic Preservation Act (NHPA) (54 U.S.C. 300101 *et seq.*) and NEPA, NOAA identified historic properties and assessed the potential effects of the undertaking (implementation of the revised regulations and adoption of the new management plan) on such properties. NOAA determined that this undertaking would result in no adverse effects to historic properties because it is a planning and administrative effort not likely to have physically direct or indirect effects to historic properties. NOAA notified the California State Historic Preservation Officer of this determination upon publication of the proposed rule and draft management plan. The State Historic Preservation Officer reviewed NOAA's determination and notified NOAA by letter on January 15, 2021, that they have no comments for this action. NOAA has no further obligations under NHPA Section 106 at this time. If specific projects do arise out of management plan implementation, NOAA will conduct Section 106 consultation at that time, as needed.

G. Endangered Species Act

The Endangered Species Act (ESA) of 1973 as amended (16 U.S.C. 1531, *et seq.*), provides for the conservation of endangered and threatened species of fish, wildlife, and plants. Federal agencies have an affirmative mandate to conserve ESA-listed species. Section 7(a)(2) of the ESA requires Federal agencies, in consultation with the National Marine Fisheries Service (NMFS) and/or the U.S. Fish and Wildlife Service, to ensure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of an ESA-listed species or result in the destruction or adverse modification of designated critical habitat. NOAA's ONMS completed informal consultation under Section 7 of the ESA with NOAA's Office of Protected Resources and the U.S. Fish and Wildlife Service for potential impacts of this action on ESA-listed species and designated critical habitat. The consulting agencies concurred with NOAA ONMS's determination that the action may affect, but is not likely to adversely affect, listed species and/or designated critical habitat. Additional details and correspondence related to informal consultation under ESA are included in the Final EA.

H. Marine Mammal Protection Act

The Marine Mammal Protection Act (MMPA) of 1972 (16 U.S.C. 1361 *et seq.*), as amended, prohibits the ''take'' [17] of marine mammals in U.S. waters. Section 101(a)(5)(A–D) of the MMPA provides a mechanism for allowing, upon request, the ''incidental,'' but not intentional, taking of small numbers of marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing or directed research on marine mammals) within a specified geographic region. ONMS determined that the action would not cause the take of any marine mammal protected under the MMPA and therefore potential impacts to marine mammals did not rise to a level that required consultation under MMPA.

I. Coastal Zone Management Act

The principal objectives of the Coastal Zone Management Act (CZMA), 16 U.S.C. 1451 *et seq.,* are to encourage and assist states in developing coastal management programs, to coordinate state activities, and to preserve, protect, develop and, where possible, restore or enhance the resources of the Nation's coastal zone. Section 307(c) of the CZMA requires Federal activity affecting the land or water uses or natural resources of a state's coastal zone to be consistent with that state's approved coastal management program to the maximum extent practicable. 16 U.S.C. 1456(c). In July 2020, NOAA initiated Federal consistency review with the California Coastal Commission. The California Coastal Commission provided comments to NOAA on the proposed rule. On August 12, 2021, NOAA provided the California Coastal Commission with a revised description of the proposed action and a summary of changes made in response to public comment and consultations. On September 2, 2021, the California Coastal Commission issued a letter of concurrence to NOAA.

[17] The MMPA defines take as: ''to harass, hunt, capture, or kill, or attempt to harass, hunt, capture or kill any marine mammal.'' 16 U.S.C. 1362. Harassment means any act of pursuit, torment, or annoyance which, (1) has the potential to injure a marine mammal or marine mammal stock in the wild (Level A Harassment); or (2) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering (Level B Harassment).

List of Subjects in 15 CFR Part 922

Administrative practice and procedure, Coastal zone, Fishing gear, Marine resources, Natural resources, Penalties, Recreation and recreation areas, Wildlife.

Nicole R. LeBoeuf,

Assistant Administrator, National Ocean Service, National Oceanic and Atmospheric Administration.

For the reasons set forth above, NOAA is amending part 922, title 15 of the Code of Federal Regulations as follows:

PART 922—NATIONAL MARINE SANCTUARY PROGRAM REGULATIONS

■ 1. The authority citation for part 922 continues to read as follows:

Authority: 16 U.S.C. 1431 *et seq.*

Subpart M—Monterey Bay National Marine Sanctuary

■ 2. Amend § 922.131 by adding the definition for ''Beneficial use of dredged material'' in alphabetical order to read as follows:

§ 922.131 Definitions.

* * * * *

Beneficial use of dredged material means the use of dredged material removed from any of the four public harbors adjacent to the sanctuary (Pillar Point, Santa Cruz, Moss Landing, and Monterey) that has been determined by the Director to be suitable as a resource for habitat protection or restoration purposes only. Beneficial use of dredged material is not disposal of dredged material.

* * * * *

■ 3. Amend § 922.132 by:

■ a. Revising paragraphs (a)(7) and (c)(1).

■ b. In paragraph (f), adding a sentence before the last sentence in the paragraph.

The revisions and addition read as follows:

§ 922.132 Prohibited or otherwise regulated activities.

(a) * * *

(7) Operating motorized personal watercraft within the Sanctuary except within the four designated zones and access routes within the Sanctuary described in appendix E to this subpart. Zone Five (at Pillar Point) exists only when a High Surf Advisory has been issued by the National Weather Service and is in effect for San Mateo County, and only during December, January, and February.

* * * * *

(c)(1) All Department of Defense activities must be carried out in a manner that avoids to the maximum extent practicable any adverse impacts on Sanctuary resources and qualities. The prohibitions in paragraphs (a)(2) through (12) of this section do not apply to existing military activities carried out by the Department of Defense, as specifically identified in the Final Environmental Impact Statement and Management Plan for the Proposed Monterey Bay National Marine Sanctuary (NOAA, 1992). For purposes of the Davidson Seamount Management Zone, these activities are listed in the 2021 Final Environmental Assessment for Monterey Bay National Marine Sanctuary Management Plan Review. New activities may be exempted from the prohibitions in paragraphs (a)(2) through (12) of this section by the Director after consultation between the Director and the Department of Defense.

* * * * *

(f) * * * For the purposes of this subpart, the disposal of dredged material does not include the beneficial use of dredged material as defined by § 922.131. * * *

■ 4. Revise appendix E to subpart M to read as follows:

Appendix E to Subpart M of Part 922—Motorized Personal Watercraft Zones and Access Routes Within the Sanctuary

[Coordinates listed in this appendix are unprojected (Geographic) and based on the North American Datum of 1983]

The five zones and access routes are:

(1) The 0.96 mi² area off Pillar Point Harbor from harbor launch ramps, through the harbor entrance to the northern boundary of Zone One. The boundary for Zone 1 begins at Point 1 in the coordinate table listed below and continues to each subsequent point in numerical order ending at Point 6.

Point ID No.	Latitude	Longitude
1 (flashing white 5-second breakwater entrance light and horn at the seaward end of the outer west breakwater—mounted on 50-ft high white cylindrical structure).	37.49402	−122.48471
2 (triangular red dayboard with a red reflective border and flashing red 6-second light at the seaward end of the outer east breakwater—mounted on 30-ft high skeleton tower).	37.49534	−122.48568
3 (bend in middle of outer east breakwater, 660 yards west of the harbor entrance)	37.49707	−122.47941
4 (Southeast Reef—southern end green gong buoy "1S" with flashing green 6-second light)	37.46469	−122.46971
5 (red entrance buoy "2" with flashing red 4-second light)	37.47284	−122.48411
6 (flashing white 5-second breakwater entrance light and horn at the seaward end of the outer west breakwater—mounted on 50-ft high white cylindrical structure).	37.49402	−122.48471

(2) The 2.63 mi² area off of Santa Cruz Small Craft Harbor from harbor launch ramps, through the harbor entrance, and then along a 100-yard wide access route to the south-southwest along a bearing of approximately 196° true (183° magnetic) toward the red and white whistle buoy at 36.93899 N, 122.009612 W, until crossing between the two yellow can buoys marking, respectively, the northeast and northwest corners of the zone. The boundary for Zone 2 begins at Point 1 in the coordinate table listed below and continues to each subsequent point in numerical order ending at Point 5.

Point ID No.	Latitude	Longitude
1 (red/white striped whistle buoy "SC" with flashing white Morse code "A" light)	36.93899	−122.00961
2 (yellow can buoy)	36.95500	−122.00967
3 (yellow can buoy)	36.94167	−121.96667
4 (yellow can buoy)	36.92564	−121.96668
5 (red/white striped whistle buoy "SC" with flashing white Morse code "A" light)	36.93899	−122.00961

(3) The 2.29 mi² area off of Moss Landing Harbor from harbor launch ramps, through harbor entrance, and then along a 100-yard wide access route southwest along a bearing of approximately 230° true (217° magnetic) to the red and white bell buoy at 36.79893 N, 121.80157 W. The boundary for Zone 3 begins at Point 1 in the coordinate table listed below and continues to each subsequent point in numerical order ending at Point 5.

Point ID No.	Latitude	Longitude
1 (red/white striped bell buoy "MLA" with flashing white Morse code "A" light)	36.79893	−121.80157
2 (yellow can buoy)	36.77833	−121.81667
3 (yellow can buoy)	36.83333	−121.82167
4 (yellow can buoy)	36.81500	−121.80333
5 (red/white striped bell buoy "MLA" with flashing white Morse code "A" light)	36.79893	−121.80157

(4) The 3.10 mi² area off of Monterey Harbor from harbor launch ramps to a point midway between the seaward end of the U.S. Coast Guard Pier and the seaward end of Wharf 2, and then along a 100-yard wide access route to the northeast along a bearing of approximately 67° true (54° magnetic) to the yellow can buoy marking the southeast corner of the zone. The boundary for Zone 4 begins at Point 1 in the coordinate table listed below and continues to each subsequent point in numerical order ending at Point 6.

Point ID No.	Latitude	Longitude
1 (yellow can buoy)	36.61146	−121.87696
2 (red bell buoy "4" with flashing red 4-second light)	36.62459	−121.89594
3 (yellow can buoy)	36.65168	−121.87416
4 (yellow can buoy)	36.63833	−121.85500
6 (yellow can buoy)	36.61146	−121.87696

(5) The 0.13 mi² area near Pillar Point from the Pillar Point Harbor entrance along a 100-yard wide access route to the south along a bearing of approximately 174° true (161° magnetic) to the green bell buoy (identified as ''Buoy 3'') at 37.48154 N, 122.48156 W and then along a 100-yard wide access route northwest along a bearing of approximately 284° true (271° magnetic) to the green gong buoy (identified as ''Buoy 1'') at 37.48625 N, 122.50603 W, the southwest boundary of Zone Five. Zone Five exists only when a High Surf Advisory has been issued by the National Weather Service and is in effect for San Mateo County and only during December, January, and February. The boundary for Zone 5 begins at Point 1 in the coordinate table listed below and continues to each subsequent point in numerical order ending at Point 5.

Point ID No.	Latitude	Longitude
1 (green gong buoy "1" with flashing green 2.5-second light)	37.48625	−122.50603
2 (intersection of sight lines due north of green gong buoy "1" and due west of Sail Rock)	37.49305	−122.50603
3 (Sail Rock)	37.49305	−122.50105
4 (intersection of sight lines due east of green gong buoy "1" and due south of Sail Rock)	37.48625	−122.50105
5 (green gong buoy "1" with flashing green 2.5-second light)	37.48625	−122.50603

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DEPARTMENT OF THE TREASURY

Financial Crimes Enforcement Network

31 CFR Part 1010

RIN 1506–AB56

Orders Imposing Additional Reporting and Recordkeeping Requirements

AGENCY: Financial Crimes Enforcement Network (''FinCEN''), Treasury.

ACTION: Final rule.

SUMMARY: FinCEN is issuing this final rule to update its regulation to reflect amendments to the underlying statute concerning the authority of FinCEN to issue orders imposing additional reporting and recordkeeping requirements on financial institutions and nonfinancial trades or businesses in a geographic area.

DATES: *Effective Date:* November 15, 2021.

FOR FURTHER INFORMATION CONTACT: The FinCEN Regulatory Support Section at (800) 767–2825 or electronically at *https://www.fincen.gov/contact.*

SUPPLEMENTARY INFORMATION:

I. Background

The Currency and Foreign Transactions Reporting Act of 1970, as amended, is the legislative framework commonly referred to as the Bank Secrecy Act (BSA).[1]

In 1988, the Anti-Drug Abuse Act amended the BSA, codified in relevant part at 31 U.S.C. 5326, to authorize the Secretary to impose additional reporting and recordkeeping requirements on domestic financial institutions in a geographic area.[2] This grant of authority to the Secretary did not require the promulgation of an implementing regulation, and therefore was, and continues to be, self-executing.

Nevertheless, in 1989, Treasury issued a regulation incorporating the terms of Section 5326 that were in effect at that time. The regulation mirrored the statute, with the addition of certain clarifying and procedural language. *See* 54 FR 33675 (Aug. 16, 1989) (now codified at 31 CFR 1010.370).[3] For example, the regulation substituted ''and/or'' for ''and'' in the first paragraph to make clear, consistent with the statute, that the Secretary could impose reporting or recordkeeping requirements upon a finding that such requirements are necessary, but need not do both. The regulation also interpreted the statutory phrase ''geographic area'' to mean ''any area in one or more States of the United States, the District of Columbia, the Commonwealth of Puerto Rico, the United States Virgin Islands, Guam, the Commonwealth of the Northern Mariana Islands, American Samoa, the Trust Territory of the Pacific Islands, the territories and possessions of the United States, and/or political subdivision or subdivisions thereof . . . .'' In addition, the regulation specified certain procedures, including that the Secretary would direct any order to the Chief Executive Officer of a reporting financial institution and would prescribe certain information in the order.

In subsequent years, Section 5326 was amended three times in a manner that expanded the Secretary's authority. In 1992, the Annunzio-Wylie Anti-Money Laundering Act amended Section 5326 by, among other things, prohibiting financial institutions from disclosing the existence of an order to any person except as prescribed by the Secretary.[4]

In 2001, the Uniting and Strengthening America by Providing Appropriate Tools Required to Intercept and Obstruct Terrorism Act of 2001 (''USA PATRIOT Act'') extensively amended the BSA, including Section 5326 by adding ''nonfinancial trade or business'' after ''financial institution'' where that phrase appears, thereby authorizing the Secretary to issue orders to nonfinancial trades or businesses in addition to financial institutions. The Act also amended Section 5326 to extend the maximum period for an order (unless renewed) from 60 days to 180 days.[5]

In 2017, the Countering America's Adversaries Through Sanctions Act further amended Section 5326. This Act amended Section 5326's original title (''Records of certain coin and currency

[1] The BSA is codified at 12 U.S.C. 1829b, 12 U.S.C. 1951–1960, 31 U.S.C. 5311–5314 and 5316–5336, and notes thereto, with implementing regulations at 31 CFR chapter X.

[2] Public Law 100–69, Title VI, Sec. 6185(c) (Nov. 18, 1988) (codified at 31 U.S.C. 5326).

[3] The original regulation was codified at 31 CFR 103.26. In 2011, FinCEN transferred its regulations from 31 CFR part 103 to 31 CFR chapter X.

[4] Public Law 102–550, Title XV, Sec. 1562 (Oct. 28, 1992) (now codified at 31 U.S.C. 5326(c)).

[5] Public Law 107–56, Title III, Secs. 353(d), 365(c)(2)(B) (Oct. 26, 2001) (now codified at 31 U.S.C. 5326(d)).

transactions'') by striking out the phrase ''coin and currency'' before ''transactions.'' The Act also replaced the reference to any ''coins,'' ''currency,'' and ''monetary instrument'' with the word ''funds,'' thereby making clear that a transaction need not involve only coin, currency, or monetary instruments to be covered under an order. The section was also amended to change the Secretary's required finding that an order be ''necessary to carry out the purposes of this subtitle *or* to prevent evasions thereof.'' In replacing ''and'' with ''or,'' this amendment thereby required one such finding, but not both.[6]

The elements of the regulation that incorporated the terms of the statute in 1989 were not intended to limit the Secretary's authority under the statute. Accordingly, as subsequent amendments described above have expanded the Secretary's authority, FinCEN has understood the authority to be coextensive with the statute. To avoid any potential confusion regarding FinCEN's authority under the statute, this final rule updates the regulation to reflect the subsequent statutory amendments. This rule does not materially amend the other provisions in the regulation, except for one amendment to FinCEN's procedure for directing orders to chief executive officers. The rule amends that procedure to conform it to the amended statute by adding ''nonfinancial trades or businesses'' after ''financial institution'' in the paragraph where the procedure is described.

II. Section-by-Section Analysis

A. Section 1010.370 Section Title

The section heading is changed from ''Reports of certain domestic coin and currency transactions'' to ''Reports of certain domestic transactions'' to align with the statutory Section Title.

B. Section 1010.370(a)

Paragraph (a) has been divided into three parts: (a)(1), (2), and (3). The revised paragraph (a)(1) contains the language in current § 1010.370(a), but with the following additions and substitutions of terms that are reflected in 31 U.S.C. 5326(a): ''chapter or to'' is substituted for ''chapter and to''; '', or any domestic nonfinancial trade or business or group of domestic nonfinancial trades or businesses,'' is added after ''group of domestic financial institutions''; ''transfer of funds (as the Secretary may describe in such order)'' is substituted for ''transfer of United States coins or currency (or such other monetary instruments as the Secretary may describe in such order)''; and ''or group of domestic financial institutions, or domestic nonfinancial trade or business or group of domestic nonfinancial trades or businesses'' is added after ''such financial institution'', and further adds ''nonfinancial trade or business'' after ''financial institution'' to clarify FinCEN's procedure for directing orders to chief executive officers, if any.

Paragraphs (a)(2) and (3) reflect the language set forth in 31 U.S.C. 5326(b).

C. Section 1010.370(b)

Paragraph (b) contains the language in current § 1010.370(b), but substitutes ''funds'' for ''currency'' and ''currency and/or monetary instruments'' to reflect the use of the term ''funds'' throughout 31 U.S.C. 5326.

D. Section 1010.370(d)(1)

Paragraph (d)(1) contains the language in current § 1010.370(d)(1), but replaces ''60 days'' with ''180 days,'' to reflect the language in 31 U.S.C. 5326(d).

E. Section 1010.370(e)

New paragraph (e) reflects the nondisclosure language that is set forth in 31 U.S.C. 5326(c).

III. Administrative Procedure Act

The Administrative Procedure Act (APA) (codified in relevant part at 5 U.S.C. 553), generally requires that agencies give interested persons an opportunity to participate in a rulemaking by the submission of comments, except when, among other reasons, the agency is amending its own ''rules of agency organization, procedure, or practice'' or the agency finds good cause that notice and public procedure are ''impracticable, unnecessary, or contrary to the public interest.'' Likewise, the APA requires a delayed effective date for a rule except under certain conditions, including rules of agency procedure, and as provided by the agency for good cause found and published with the rule.

FinCEN finds that public procedure is unnecessary, as this final rule merely updates the regulation to reflect the terms set forth in the underlying statute in order to avoid any potential confusion regarding FinCEN's statutory authority under Section 5326. Because the final rule conforms the regulation to the statute and reflects no discretionary or substantive determination, public procedure would not inform this rule. For similar reasons, FinCEN also finds that a delayed effective date is unnecessary. Because FinCEN understands its authority to be coextensive with the statute, this update to the regulation does not alter FinCEN's authority and merely provides clarity to the public.

In conforming the regulation to the statute, this rule also adds the phrase ''nonfinancial trades or businesses'' after ''financial institution'' in the provision relating to FinCEN's procedure for directing orders to chief executive officers. This update does not change the procedure specified in the regulation, but only updates it to reflect the statute's inclusion of ''nonfinancial trades or businesses.'' FinCEN finds that public procedure and a delayed effective date are unnecessary for this amendment because it amends a rule of agency procedure, and in any event, merely conforms that rule to the statute.

IV. Regulatory Flexibility Act

Because no notice of proposed rulemaking is required, the provisions of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) do not apply.

V. Executive Order 12866

This final rule is not a significant regulatory action under section 3.f. of Executive Order 12866.

VI. Paperwork Reduction Act

The collection of information contained in this rule has been reviewed and approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), and has been assigned OMB Control Number 1506–0056. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number.

List of Subjects in 31 CFR Part 1010

Administrative practice and procedure, Banks, Banking, Currency, Foreign banking, Foreign currencies, Investigations, Penalties, Reporting and recordkeeping requirements, Terrorism.

Authority and Issuance

For the reasons set forth in the preamble, part 1010 of chapter X of title 31 of the Code of Federal Regulations are amended as follows:

PART 1010—GENERAL PROVISIONS

■ 1. The authority citation for part 1010 is revised to read:

Authority: 12 U.S.C. 1829b and 1951–1960; 31 U.S.C. 5311–5314 and 5316–5336; title III, sec. 314, Pub. Law 107–56, 115 Stat. 307; sec. 701, Pub. L. 114–74, 129 Stat. 599.

■ 2. Section 1010.370 is amended by revising the section heading and

[6] Public Law 115–44, Title II, Sec. 275(a) (Aug. 2, 2017) (codified at 31 U.S.C. 5326).

paragraphs (a), (b), and (d)(1) and adding paragraph (e) to read as follows:

§ 1010.370 Reports of certain domestic transactions.

(a)(1) If the Secretary of the Treasury finds, upon the Secretary's own initiative or at the request of an appropriate Federal or State law enforcement official, that reasonable grounds exist for concluding that additional recordkeeping and/or reporting requirements are necessary to carry out the purposes of this chapter or to prevent persons from evading the reporting/recordkeeping requirements of this chapter, the Secretary may issue an order requiring any domestic financial institution or group of domestic financial institutions, or any domestic nonfinancial trade or business or group of domestic nonfinancial trades or businesses, in a geographic area, and any other person participating in the type of transaction, to file a report in the manner and to the extent specified in such order. The order shall contain such information as the Secretary may describe concerning any transaction in which such financial institution or group of domestic financial institutions, or domestic nonfinancial trade or business or group of domestic nonfinancial trades or businesses is involved for the payment, receipt, or transfer of funds (as the Secretary may describe in such order) the total amounts or denominations of which are equal to or greater than an amount which the Secretary may prescribe.

(2) The Secretary may, by regulation or order, require any depository institution (as defined in section 3(c) of the Federal Deposit Insurance Act)—

(i) To request any financial institution or nonfinancial trade or business (other than a depository institution) which engages in any reportable transaction with the depository institution to provide the depository institution with a copy of any report filed by the financial institution or nonfinancial trade or business under the Title 31 provisions of the Bank Secrecy Act with respect to any prior transaction (between such financial institution or nonfinancial trade or business and any other person) which involved any portion of the funds which are involved in the reportable transaction with the depository institution; and

(ii) If no copy of any report described in paragraph (a)(2)(i) of this section is received by the depository institution in connection with any reportable transaction to which paragraph (a)(2)(i) applies, to submit (in addition to any report required under this subchapter with respect to the reportable transaction) a written notice to the Secretary that the financial institution or nonfinancial trade or business failed to provide any copy of such report.

(3) For purposes of paragraph (a)(2) of this section, the term *reportable transaction* means any transaction involving funds (as the Secretary may describe in the regulation or order) the total amounts or denominations of which are equal to or greater than an amount which the Secretary may prescribe.

(b) An order issued under paragraph (a) of this section shall be directed to the Chief Executive Officer of the financial institution or nonfinancial trade or business and shall designate one or more of the following categories of information to be reported: Each deposit, withdrawal, exchange of funds or other payment or transfer, by, through or to such financial institution specified in the order, which involves all or any class of transactions in funds equal to or exceeding an amount specified in the order.

* * * * *

(d)(1) No order issued pursuant to paragraph (a) of this section shall prescribe a reporting period of more than 180 days unless renewed pursuant to the requirements of paragraph (a).

* * * * *

(e) No financial institution or nonfinancial trade or business or officer, director, employee, or agent of a financial institution or nonfinancial trade or business subject to an order under this section may disclose the existence of, or terms of, the order to any person except as prescribed by the Secretary.

Dated: November 5, 2021.

Himamauli Das,

Acting Director, Financial Crimes Enforcement Network.

[FR Doc. 2021–24602 Filed 11–12–21; 8:45 am]

BILLING CODE 4810–02–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 100

[Docket No. USCG–2021–0772]

Special Local Regulation: Palm Beach Holiday Boat Parade

AGENCY: Coast Guard, DHS.

ACTION: Notice of enforcement of regulation.

SUMMARY: The Coast Guard will enforce a special local regulation on December 4, 2021 to provide for the safety and security of navigable waterways during the Palm Beach Holiday Boat Parade. During the enforcement period, all non-participant persons and vessels will be prohibited from entering, transiting, anchoring, or remaining within the regulated area unless authorized by the Captain of the Port Miami or a designated representative. The operator of any vessel in the regulated area must comply with instructions from the Coast Guard or designated representative.

DATES: The regulation in 33 CFR 100.702, Table 1 to § 100.702, Line 9, will be enforced on December 4, 2021, from 5:30 p.m. through 8:30 p.m.

FOR FURTHER INFORMATION CONTACT: If you have questions about this notice of enforcement, call or email Mr. Omar Beceiro, Sector Miami Waterways Management Division, U.S. Coast Guard: Telephone: 305–535–4317, Email: *Omar.Beceiro@uscg.mil.*

SUPPLEMENTARY INFORMATION: The Coast Guard will enforce a special local regulation for the Palm Beach Holiday Boat Parade published in 33 CFR 100.702, Table 1 to § 100.702, Line 9, on December 4, 2021 from 5:30 p.m. through 8:30 p.m. This action is being taken to provide for the safety and security of navigable waterways during this one-day event. The regulations for marine events within the Seventh Coast Guard District can be found in § 100.702(c) covers this event and Table 1 to § 100.702, Line 9, specifies the location of the special local regulation for the Palm Beach Holiday Boat Parade, which encompasses a moving buffer zone of 50 yards around the parade as it travels along the Intracoastal Waterway in Palm Beach, FL. Only event sponsor designated participants and official patrol vessels will be allowed to enter the regulated area. Spectators may contact the Coast Guard Patrol Commander to request permission to pass through the regulated area. If permission is granted, spectators must pass directly through the regulated area at a safe speed without loitering.

In addition to this notice of enforcement in the **Federal Register**, the Coast Guard will inform the public through Local Notice to Mariners and marine information broadcasts at least 24 hours in advance of the enforcement of the special local regulation.

Dated: October 27, 2021.

J.F. Burdian,

Captain, U.S. Coast Guard, Captain of the Port Miami.

[FR Doc. 2021–24906 Filed 11–12–21; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 721

[EPA–HQ–OPPT–2020–0497; FRL–8215–01–OCSPP]

RIN 2070–AB27

Significant New Use Rules on Certain Chemical Substances (20–10.B)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is issuing significant new use rules (SNURs) under the Toxic Substances Control Act (TSCA) for chemical substances which were the subject of premanufacture notices (PMNs). This action requires persons to notify EPA at least 90 days before commencing manufacture (defined by statute to include import) or processing of any of these chemical substances for an activity that is designated as a significant new use by this rule. This action further requires that persons not commence manufacture or processing for the significant new use until they have submitted a Significant New Use Notice (SNUN), EPA has conducted a review of the notice, made an appropriate determination on the notice, and has taken any risk management actions as are required as a result of that determination.

DATES: This rule is effective on January 14, 2022. For purposes of judicial review, this rule shall be promulgated at 1 p.m. (e.s.t.) on November 29, 2021.

FOR FURTHER INFORMATION CONTACT:

For technical information contact: William Wysong, New Chemicals Division (7405M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001; telephone number: (202) 564–4163; email address: *wysong.william@epa.gov.*

For general information contact: The TSCA-Hotline, ABVI-Goodwill, 422 South Clinton Ave., Rochester, NY 14620; telephone number: (202) 554–1404; email address: *TSCA-Hotline@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you manufacture, process, or use the chemical substances contained in this rule. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Manufacturers or processors of one or more subject chemical substances (NAICS codes 325 and 324110), *e.g.,* chemical manufacturing and petroleum refineries.

This action may also affect certain entities through pre-existing import certification and export notification rules under TSCA, which would include the SNUR requirements. Chemical importers are subject to the TSCA section 13 (15 U.S.C. 2612) import provisions. The EPA policy in support of import certification appears at 40 CFR part 707, subpart B. In addition, pursuant to 40 CFR 721.20, any persons who export or intend to export a chemical substance that is the subject of this rule are subject to the export notification provisions of TSCA section 12(b) (15 U.S.C. 2611(b)), and must comply with the export notification requirements in 40 CFR part 707, subpart D.

B. How can I access the docket?

The docket includes information considered by the Agency in developing the proposed and final rules. The docket for this action, identified by docket identification (ID) number EPA–HQ–OPPT–2020–0497, is available at *https://www.regulations.gov* and at the Office of Pollution Prevention and Toxics Docket (OPPT Docket), Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. 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 OPPT Docket is (202) 566–0280. Please review the visitor instructions and additional information about the docket available at *https://www.epa.gov/dockets.*

Due to the public health emergency, the EPA Docket Center (EPA/DC) and Reading Room is closed to visitors with limited exceptions. The staff continues to provide remote customer service via email, phone, and webform. For the latest status information on EPA/DC services and docket access, visit *https://www.epa.gov/dockets.*

II. Background

A. What action is the Agency taking?

EPA is finalizing SNURs under TSCA section 5(a)(2) for chemical substances which were the subject of PMNs P–18–289, P–18–330, P–18–334, P–18–335, and P–18–337. These SNURs require persons who intend to manufacture or process any of these chemical substances for an activity that is designated as a significant new use to notify EPA at least 90 days before commencing that activity.

Previously, in the **Federal Register** of October 20, 2020 (85 FR 66506) (FRL–10015–28), EPA proposed SNURs for these chemical substances. More information on the specific chemical substances subject to this final rule can be found in the **Federal Register** document proposing the SNURs. The docket includes information considered by the Agency in developing the proposed and final rules, including public comments and EPA's responses to the public comments received on the proposed rules, as described in Unit IV.

B. What is the Agency's authority for taking this action?

TSCA section 5(a)(2) (15 U.S.C. 2604(a)(2)) authorizes EPA to determine that a use of a chemical substance is a ''significant new use.'' EPA must make this determination by rule after considering all relevant factors, including the four TSCA section 5(a)(2) factors listed in Unit III.

C. Do the SNUR general provisions apply?

General provisions for SNURs appear in 40 CFR part 721, subpart A. These provisions describe persons subject to the rule, recordkeeping requirements, exemptions to reporting requirements, and applicability of the rule to uses occurring before the effective date of the rule. Provisions relating to user fees appear at 40 CFR part 700. Pursuant to 40 CFR 721.1(c), persons subject to these SNURs must comply with the same SNUN requirements and EPA regulatory procedures as submitters of PMNs under TSCA section 5(a)(1)(A). In particular, these requirements include the information submission requirements of TSCA sections 5(b) and 5(d)(1), the exemptions authorized by TSCA sections 5(h)(1), 5(h)(2), 5(h)(3), and 5(h)(5) and the regulations at 40 CFR part 720. Once EPA receives a SNUN, EPA must either determine that the significant new use is not likely to present an unreasonable risk of injury or take such regulatory action as is associated with an alternative determination before manufacture or processing for the significant new use can commence. If EPA determines that the significant new use is not likely to present an unreasonable risk, EPA is required under TSCA section 5(g) to make public, and submit for publication

in the **Federal Register**, a statement of EPA's findings.

III. Significant New Use Determination

A. Determination Factors

TSCA section 5(a)(2) states that EPA's determination that a use of a chemical substance is a significant new use must be made after consideration of all relevant factors, including:

- The projected volume of manufacturing and processing of a chemical substance.
- The extent to which a use changes the type or form of exposure of human beings or the environment to a chemical substance.
- The extent to which a use increases the magnitude and duration of exposure of human beings or the environment to a chemical substance.
- The reasonably anticipated manner and methods of manufacturing, processing, distribution in commerce, and disposal of a chemical substance.

In determining what would constitute a significant new use for the chemical substances that are the subject of these SNURs, EPA considered relevant information about the toxicity of the chemical substances, and potential human exposures and environmental releases that may be associated with the substances, in the context of the four bulleted TSCA section 5(a)(2) factors listed in this unit. During its review of these chemicals, EPA identified certain conditions of use that are not intended by the submitters, but reasonably foreseen to occur. EPA is designating those reasonably foreseen conditions of use as well as certain other circumstances of use as significant new uses.

B. Procedures for Significant New Uses Claimed as Confidential Business Information (CBI)

By this rule, EPA is establishing certain significant new uses which have been claimed as CBI subject to Agency confidentiality regulations at 40 CFR part 2 and 40 CFR part 720, subpart E. Absent a final determination or other disposition of the confidentiality claim under 40 CFR part 2 procedures, EPA is required to keep this information confidential. EPA promulgated a procedure to deal with the situation where a specific significant new use is CBI, at 40 CFR 721.1725(b)(1) and has referenced it to apply to other SNURs.

Under these procedures a manufacturer or processor may request EPA to determine whether a specific use would be a significant new use under the rule. The manufacturer or processor must show that it has a *bona fide* intent to manufacture or process the chemical substance and must identify the specific use for which it intends to manufacture or process the chemical substance. If EPA concludes that the person has shown a *bona fide* intent to manufacture or process the chemical substance, EPA will tell the person whether the use identified in the *bona fide* submission would be a significant new use under the rule. Since most of the chemical identities of the chemical substances subject to these SNURs are also CBI, manufacturers and processors can combine the *bona fide* submission under the procedure in 40 CFR 721.1725(b)(1) with that under 40 CFR 721.11 into a single step.

If EPA determines that the use identified in the *bona fide* submission would not be a significant new use, *i.e.,* the use does not meet the criteria specified in the rule for a significant new use, that person can manufacture or process the chemical substance so long as the significant new use trigger is not met. In the case of a production volume trigger, this means that the annual production volume limit is not exceeded by the amount identified in the *bona fide* submission to EPA. Because of confidentiality concerns, EPA does not typically disclose the actual production volume that constitutes the use trigger. Thus, if the person later intends to exceed that volume, a new *bona fide* submission would be necessary to determine whether that higher volume would be a significant new use.

IV. Public Comments

EPA received a public comment from one identifying entity on the proposed rule. The Agency's response is described in a separate Response to Public Comments document that is available in the public docket for this rulemaking. In addition, EPA received three anonymous comments. They were either general in nature and did not pertain to the proposed rule or were broadly supportive of the rule and requested no changes to the rule itself; therefore, no response is required. EPA made no changes to the final rule based on these comments.

V. Substances Subject to This Rule

EPA is establishing significant new use and recordkeeping requirements for chemical substances in 40 CFR part 721, subpart E. In Unit IV. of the proposed SNUR, EPA provided the following information for each chemical substance:

- PMN number.
- Chemical name (generic name, if the specific name is claimed as CBI).
- Chemical Abstracts Service (CAS) Registry number (if assigned for non-confidential chemical identities).
- Basis for the SNUR.
- Potentially useful information.
- CFR citation assigned in the regulatory text section of this final rule.

The regulatory text section of these rules specifies the activities designated as significant new uses. Certain new uses, including production volume limits and other uses designated in the rules, may be claimed as CBI.

VI. Rationale and Objectives of the Rule

A. Rationale

During review of the PMNs submitted for the chemical substances that are the subject of these SNURs and as further discussed in Unit IV. of the proposed rule, EPA identified certain other reasonably foreseen conditions of use in addition to those conditions of use intended by the submitter. EPA has determined that the chemical under the intended conditions of use is not likely to present an unreasonable risk. However, EPA has not assessed risks associated with the reasonably foreseen conditions of use. EPA is designating these conditions of use as well as certain other circumstances of use as significant new uses. As a result, those significant new uses cannot occur without going through a separate, subsequent EPA review and determination process associated with a SNUN.

B. Objectives

EPA is issuing these SNURs because the Agency wants:

- To have an opportunity to review and evaluate data submitted in a SNUN before the notice submitter begins manufacturing or processing a listed chemical substance for the described significant new use.
- To be obligated to make a determination under TSCA section 5(a)(3) regarding the use described in the SNUN, under the conditions of use. The Agency will either determine under section 5(a)(3)(C) that the significant new use is not likely to present an unreasonable risk, including an unreasonable risk to a potentially exposed or susceptible subpopulation identified as relevant by the Administrator under the conditions of use, or make a determination under TSCA section 5(a)(3)(A) or (B) and take the required regulatory action associated with the determination, before manufacture or processing for the significant new use of the chemical substance can occur.
- To be able to complete its review and determination on each of the PMN

substances, while deferring analysis on the significant new uses proposed in these rules unless and until the Agency receives a SNUN.

Issuance of a SNUR for a chemical substance does not signify that the chemical substance is listed on the TSCA Inventory. Guidance on how to determine if a chemical substance is on the TSCA Inventory is available on the internet at *https://www.epa.gov/tsca-inventory.*

VII. Applicability of the Rules to Uses Occurring Before the Effective Date of the Final Rule

To establish a significant new use, EPA must determine that the use is not ongoing. The chemical substances subject to this rule were undergoing premanufacture review at the time of signature of the proposed rule and were not on the TSCA inventory. In cases where EPA has not received a notice of commencement (NOC) and the chemical substance has not been added to the TSCA Inventory, no person may commence such activities without first submitting a PMN. Therefore, for the chemical substances subject to these SNURs, EPA concluded at the time of signature of the proposed rule that the designated significant new uses were not ongoing.

EPA designated October 7, 2020 (the date of web posting of the proposed rule) as the cutoff date for determining whether the new use is ongoing. The objective of EPA's approach is to ensure that a person cannot defeat a SNUR by initiating a significant new use before the effective date of the final rule.

Persons who began commercial manufacture or processing of the chemical substances for a significant new use identified on or after that date will have to cease any such activity upon the effective date of the final rule. To resume their activities, these persons would have to first comply with all applicable SNUR notification requirements and EPA would have to take action under TSCA section 5 allowing manufacture or processing to proceed.

VIII. Development and Submission of Information

EPA recognizes that TSCA section 5 does not require development of any particular new information (*e.g.,* generating test data) before submission of a SNUN. There is an exception: If a person is required to submit information for a chemical substance pursuant to a rule, Order or consent agreement under TSCA section 4, then TSCA section 5(b)(1)(A) requires such information to be submitted to EPA at the time of submission of the SNUN.

In the absence of a rule, Order, or consent agreement under TSCA section 4 covering the chemical substance, persons are required only to submit information in their possession or control and to describe any other information known to or reasonably ascertainable by them (see 40 CFR 720.50). However, upon review of PMNs and SNUNs, the Agency has the authority to require appropriate testing. Unit IV. of the proposed rule lists potentially useful information for all SNURs listed here. Descriptions are provided for informational purposes. The potentially useful information identified in Unit IV. of the proposed rule will be useful to EPA's evaluation in the event that someone submits a SNUN for the significant new use. Companies who are considering submitting a SNUN are encouraged, but not required, to develop the information on the substance, which may assist with EPA's analysis of the SNUN.

EPA strongly encourages persons, before performing any testing, to consult with the Agency pertaining to protocol election. Furthermore, pursuant to TSCA section 4(h), which pertains to reduction of testing in vertebrate animals, EPA encourages consultation with the Agency on the use of alternative test methods and strategies (also called New Approach Methodologies, or NAMs), if available, to generate the recommended test data. EPA encourages dialog with Agency representatives to help determine how best the submitter can meet both the data needs and the objective of TSCA section 4(h). For more information on alternative test methods and strategies to reduce vertebrate animal testing, visit *https://www.epa.gov/assessing-and-managing-chemicals-under-tsca/alternative-test-methods-and-strategies-reduce.*

The potentially useful information described in Unit IV. of the proposed rule may not be the only means of providing information to evaluate the chemical substance associated with the significant new uses. However, submitting a SNUN without any test data may increase the likelihood that EPA will take action under TSCA sections 5(e) or 5(f). EPA recommends that potential SNUN submitters contact EPA early enough so that they will be able to conduct the appropriate tests.

SNUN submitters should be aware that EPA will be better able to evaluate SNUNs which provide detailed information on the following:

- Human exposure and environmental release that may result from the significant new use of the chemical substances.

IX. SNUN Submissions

According to 40 CFR 721.1(c), persons submitting a SNUN must comply with the same notification requirements and EPA regulatory procedures as persons submitting a PMN, including submission of test data on health and environmental effects as described in 40 CFR 720.50. SNUNs must be submitted on EPA Form No. 7710–25, generated using e-PMN software, and submitted to the Agency in accordance with the procedures set forth in 40 CFR 720.40 and 721.25. E–PMN software is available electronically at *https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca.*

X. Economic Analysis

EPA has evaluated the potential costs of establishing SNUN requirements for potential manufacturers and processors of the chemical substances subject to this rule. EPA's complete economic analysis is available in the docket for this rulemaking.

XI. Statutory and Executive Order Reviews

Additional information about these statutes and executive orders can be found at *https://www.epa.gov/laws-regulations-and-executive-orders.*

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

This action establishes SNURs for new chemical substances that were the subject of PMNs. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011).

B. Paperwork Reduction Act (PRA)

According to PRA, 44 U.S.C. 3501 *et seq.,* an agency may not conduct or sponsor, and a person is not required to respond to a collection of information that requires OMB approval under PRA, unless it has been approved by OMB and displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in title 40 of the CFR, after appearing in the **Federal Register**, are listed in 40 CFR part 9, and included on the related collection instrument or form, if applicable.

The information collection requirements related to this action have already been approved by OMB pursuant to PRA under OMB control

number 2070–0012 (EPA ICR No. 574). This action does not impose any burden requiring additional OMB approval. If an entity were to submit a SNUN to the Agency, the annual burden is estimated to average between 30 and 170 hours per response. This burden estimate includes the time needed to review instructions, search existing data sources, gather and maintain the data needed, and complete, review, and submit the required SNUN.

The listing of the OMB control numbers of the collection instruments and their subsequent codification in the table in 40 CFR 9.1 satisfies the display requirements of the PRA and OMB's implementing regulations at 5 CFR part 1320. Since this ICR was previously subject to public notice and comment prior to OMB approval, and given the technical nature of the table in 40 CFR part 9, EPA finds that further notice and comment to amend it is unnecessary. As a result, EPA finds that there is ''good cause'' under section 553(b)(3)(B) of the Administrative Procedure Act (5 U.S.C. 553(b)(3)(B)) to amend this table in 40 CFR 9.1 without further notice and comment.

C. Regulatory Flexibility Act (RFA)

Pursuant to RFA section 605(b), 5 U.S.C. 601 *et seq.,* I hereby certify that promulgation of this SNUR would not have a significant adverse economic impact on a substantial number of small entities. The requirement to submit a SNUN applies to any person (including small or large entities) who intends to engage in any activity described in the final rule as a ''significant new use.'' Because these uses are ''new,'' based on all information currently available to EPA, it appears that no small or large entities presently engage in such activities. A SNUR requires that any person who intends to engage in such activity in the future must first notify EPA by submitting a SNUN. Although some small entities may decide to pursue a significant new use in the future, EPA cannot presently determine how many, if any, there may be. However, EPA's experience to date is that, in response to the promulgation of SNURs covering over 1,000 chemicals, the Agency receives only a small number of notices per year. For example, the number of SNUNs received was seven in Federal fiscal year (FY) 2013, 13 in FY2014, six in FY2015, 12 in FY2016, 13 in FY2017, and 11 in FY2018. Only a fraction of these were from small businesses. In addition, the Agency currently offers relief to qualifying small businesses by reducing the SNUN submission fee from $16,000 to $2,800. This lower fee reduces the total reporting and recordkeeping of cost of submitting a SNUN to about $10,116 for qualifying small firms. Therefore, the potential economic impacts of complying with this SNUR are not expected to be significant or adversely impact a substantial number of small entities. In a SNUR that published in the **Federal Register** of June 2, 1997 (62 FR 29684) (FRL–5597–1), the Agency presented its general determination that final SNURs are not expected to have a significant economic impact on a substantial number of small entities, which was provided to the Chief Counsel for Advocacy of the Small Business Administration.

D. Unfunded Mandates Reform Act (UMRA)

Based on EPA's experience with proposing and finalizing SNURs, State, local, and Tribal governments have not been impacted by these rulemakings, and EPA does not have any reasons to believe that any State, local, or Tribal government will be impacted by this action. As such, EPA has determined that this action does not impose any enforceable duty, contain any unfunded mandate, or otherwise have any effect on small governments subject to the requirements of UMRA sections 202, 203, 204, or 205 (2 U.S.C. 1501 *et seq.*).

E. Executive Order 13132: Federalism

This action will not have federalism implications because it is not expected to have a substantial direct effect on 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, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999).

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

This action will not have Tribal implications because it is not expected to have substantial direct effects on Indian Tribes, significantly or uniquely affect the communities of Indian Tribal governments and does not involve or impose any requirements that affect Indian Tribes. Accordingly, the requirements of Executive Order 13175 (65 FR 67249, November 9, 2000), do not apply to this action.

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

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997), because this is not an economically significant regulatory action as defined by Executive Order 12866, and this action does not address environmental health or safety risks disproportionately affecting children.

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

This action is not subject to Executive Order 13211 (66 FR 28355, May 22, 2001), because this action is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

In addition, since this action does not involve any technical standards, NTTAA section 12(d), 15 U.S.C. 272 note, does not apply to this action.

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

This action does not entail special considerations of environmental justice related issues as delineated by Executive Order 12898 (59 FR 7629, February 16, 1994).

K. Congressional Review Act (CRA)

This action is subject to the CRA, 5 U.S.C. 801 *et seq.,* and EPA will submit a rule report containing this rule and other required information to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects

40 CFR Part 9

Environmental protection, Reporting and recordkeeping requirements.

40 CFR Part 721

Environmental protection, Chemicals, Hazardous substances, Reporting and recordkeeping requirements.

Dated: October 26, 2021.

Tala Henry,

Deputy Director, Office of Pollution Prevention and Toxics.

Therefore, for the reasons stated in the preamble, EPA is amending 40 CFR chapter I as follows:

PART 9—OMB APPROVALS UNDER THE PAPERWORK REDUCTION ACT

■ 1. The authority citation for part 9 continues to read as follows:

Authority: 7 U.S.C. 135 *et seq.,* 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331j, 346a; 31 U.S.C. 9701; 33

U.S.C. 1251 *et seq.,* 1311, 1313d, 1314, 1318, 1321, 1326, 1330, 1342, 1344, 1345 (d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975 Comp. p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g-1, 300g-2, 300g-3, 300g-4, 300g-5, 300g-6, 300j-1, 300j-2, 300j-3, 300j-4, 300j-9, 1857 *et seq.,* 6901–6992k, 7401–7671q, 7542, 9601–9657, 11023, 11048.

■ 2. In § 9.1, amend the table by adding entries for §§ 721.11561 through 721.11565 in numerical order under the undesignated center heading ''Significant New Uses of Chemical Substances'' to read as follows:

§ 9.1 OMB approvals under the Paperwork Reduction Act.

* * * * *

40 CFR citation	OMB control No.
* * * * *	
Significant New Uses of Chemical Substances	
* * * * *	
721.11561	2070–0012
721.11562	2070–0012
721.11563	2070–0012
721.11564	2070–0012
721.11565	2070–0012
* * * * *	

* * * * *

PART 721—SIGNIFICANT NEW USES OF CHEMICAL SUBSTANCES

■ 3. The authority citation for part 721 continues to read as follows:

Authority: 15 U.S.C. 2604, 2607, and 2625(c).

■ 4. Add §§ 721.11561 through 721.11565 to subpart E to read as follows:

Subpart E—Significant New Uses for Specific Chemical Substances

Sec.

* * * * *

§ 721.11561 2-[2-(methylcarboxymono cyclic)amino)ethoxy]alcohol (generic).

§ 721.11562 Formaldehyde, polymer with alkyl aryl ketone (generic).

§ 721.11563 Propanedioic acid, 1,3-dihexyl ester.

§ 721.11564 Propanedioic acid, 1,3-dicyclohexyl ester.

§ 721.11565 Propanedioic acid, 2,2-bis(hydroxymethyl)-, 1,3-dicyclohexyl ester.

* * * * *

§ 721.11561 2-[2-(methylcarboxymono cyclic)amino)ethoxy]alcohol (generic).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified generically as 2-[2-(methylcarboxymono cyclic)amino)ethoxy]alcohol (generic).(PMN P–18–289) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(j) and (s). For purposes of § 721.80(s), the annual manufacture and importation volume is 80,000 kilograms.

(ii) [Reserved]

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (c) and (i) are applicable to manufacturers and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

(3) *Determining whether a specific use is subject to this section.* The provisions of § 721.1725(b)(1) apply to paragraph (a)(2)(i) of this section.

§ 721.11562 Formaldehyde, polymer with alkyl aryl ketone (generic).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified generically as formaldehyde, polymer with alkyl aryl ketone (PMN P–18–330) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o).

(ii) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=770.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (c), (i) and (k) are applicable to manufacturers and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11563 Propanedioic acid, 1,3-dihexyl ester.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as propanedioic acid, 1,3-dihexyl ester (PMN P–18–334; CAS No. 1431–37–4) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(g).

(ii) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=3.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (c), (i) and (k) are applicable to manufacturers and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11564 Propanedioic acid, 1,3-dicyclohexyl ester.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as propanedioic acid, 1,3-dicyclohexyl ester (PMN P–18–335; CAS No. 1152–57–4) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(g).

(ii) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=6.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (c), (i) and (k) are applicable to manufacturers and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11565 Propanedioic acid, 2,2-bis(hydroxymethyl)-, 1,3-dicyclohexyl ester.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as propanedioic acid, 2,2-

bis(hydroxymethyl)-, 1,3-dicyclohexyl ester (PMN P–18–337; CAS No. 2222732–46–7) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=95.

(ii) [Reserved]

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (c) and (k) are applicable to manufacturers and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

[FR Doc. 2021–24789 Filed 11–12–21; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2020–0512; FRL–8668–01–OCSPP]

Pyriproxyfen; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes tolerances for residues of pyriproxyfen, including its metabolites and degradates, in or on egg; poultry, fat; poultry, meat; and poultry, meat byproducts. McLaughlin Gormley King Company D/B/A MGK requested tolerances for these commodities under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective November 15, 2021. Objections and requests for hearings must be received on or before January 14, 2022 and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2020–0512, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW, Washington, DC 20460. 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 OPP Docket is (703) 305–5805.

Due to the public health concerns related to COVID–19, the EPA Docket Center (EPA/DC) and Reading Room is closed to visitors with limited exceptions. The staff continues to provide remote customer service via email, phone, and webform. For the latest status information on EPA/DC services and docket access, visit *https://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Marietta Echeverria, Acting Director, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Avenue NW, Washington, DC 20460; main telephone number: (703) 305–7090; email address: *RDFRNotices@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of EPA's tolerance regulations at 40 CFR part 180 through the Government Publishing Office's e-CFR site at *http://www.ecfr.gov/cgi-bin/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.*

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a(g), any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2020–0512 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing and must be received by the Hearing Clerk on or before January 14, 2022. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA–HQ–OPP–2020–0512, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW, Washington, DC 20460.
- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.html.*

Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

II. Summary of Petitioned-For Tolerance

In the **Federal Register** of October 27, 2020 (85 FR 68030) (FRL–10015–86), EPA issued a document pursuant to FFDCA section 408(d)(3), 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 0F8870) by McLaughlin Gormley King Company D/B/A MGK, 7325 Aspen Lane N, Minneapolis, MN 55428. The petition requested that 40 CFR 180.510 be amended by establishing tolerances for residues of the insecticide pyriproxyfen in or on eggs and all tissues (except poultry fat) at 0.03 parts per million (ppm) and poultry fat at 0.04 ppm. That document referenced a summary of the petition prepared by McLaughlin Gormley King Company D/B/A MGK, the registrant, which is available in the

docket for this action, docket ID EPA–HQ–OPP–2020–0512, at *http://www.regulations.gov.* No substantive public comments were received in response to the notice of filing.

Based upon review of the data supporting the petition and in accordance with its authority under FFDCA section 408(d)(4)(A)(i), EPA is establishing tolerances that vary from what the petitioners sought. The reasons for these changes are explained in detail in Unit IV.C.

III. Aggregate Risk Assessment and Determination of Safety

Section 408(b)(2)(A)(i) of the FFDCA allows EPA to establish a tolerance (the legal limit for a pesticide chemical residue in or on a food) only if EPA determines that the tolerance is ''safe.'' Section 408(b)(2)(A)(ii) of the FFDCA defines ''safe'' to mean that ''there is a reasonable certainty that no harm will result from aggregate exposure to the pesticide chemical residue, including all anticipated dietary exposures and all other exposures for which there is reliable information.'' This includes exposure through drinking water and in residential settings but does not include occupational exposure. Section 408(b)(2)(C) of the FFDCA requires EPA to give special consideration to exposure of infants and children to the pesticide chemical residue in establishing a tolerance and to ''ensure that there is a reasonable certainty that no harm will result to infants and children from aggregate exposure to the pesticide chemical residue. . . .''

Consistent with FFDCA section 408(b)(2)(D) and the factors specified therein, EPA has reviewed the available scientific data and other relevant information in support of this action. EPA has sufficient data to assess the hazards of and to make a determination on aggregate exposure for pyriproxyfen in or on egg; poultry, fat; poultry, meat; and poultry, meat byproducts. In an effort to streamline its publications in the **Federal Register**, EPA is not reprinting sections that repeat what has been previously published for tolerance rulemakings of the same pesticide chemical. Where scientific information concerning a particular chemical remains unchanged, the content of those sections would not vary between tolerance rulemakings and republishing the same sections is unnecessary. EPA considers referral back to those sections as sufficient to provide an explanation of the information EPA considered in making its safety determination for the new rulemaking.

EPA has previously published several tolerance rulemakings for pyriproxyfen, in which EPA concluded, based on the available information, that there is a reasonable certainty that no harm would result from aggregate exposure to pyriproxyfen and established tolerances for residues of that chemical. EPA is incorporating previously published sections from those rulemakings as described further in this rulemaking, as they remain unchanged.

Toxicological profile. For a discussion of the Toxicological Profile of pyriproxyfen, see Unit III.A. of the February 22, 2016 rulemaking (81 FR 8658) (FRL–9941–68).

Toxicological points of departure/Levels of concern. For a summary of the Toxicological Points of Departure/Levels of Concern used for the safety assessment, please refer to the September 25, 2017 risk assessment supporting the *Registration Review* for pyriproxyfen entitled, ''Pyriproxyfen: Human Health Draft Risk Assessment for Registration Review'' by going to *http://www.regulations.gov.* The referenced document is available in docket ID number EPA–HQ–OPP–2011–0677.

Exposure assessment. Much of the exposure assessment remains the same, although updates have occurred to accommodate exposures from the petitioned-for tolerances. These updates are discussed in this section; for a detailed description of the rest of the EPA approach to and assumptions for the exposure assessment, please refer to the 2017 draft human health risk assessment for *Registration Review.*

Since the recommended tolerance levels (0.1 ppm) are equal to, and not aggregated with, the existing food handling establishment (FHE) tolerance levels (0.1 ppm) for all food commodities established as part of a 2001 rulemaking (66 FR 14852) (FRL–6766–6) included in the dietary (food + drinking water) exposure and risk assessment supporting this rule, no updates to the dietary assessment are required. An unrefined chronic dietary (food + drinking water) exposure assessment was conducted using tolerance-level residues recommended under the 2017 pyriproxyfen draft human health risk assessment for *Registration Review.* This 2017 assessment assumed 100% crop treated and EPA's 2018 default processing factors. Drinking water was incorporated directly into the chronic dietary assessment. The chronic dietary (food + drinking water) exposures were estimated at 5.8% of the cPAD for the U.S. general population and 15% of the cPAD for the most highly exposed population subgroup (children 1 to 2 years old) and are below EPA's level of concern (LOC), less than 100% of the cPAD (<100% cPAD).

Since no short- or intermediate-term dermal and inhalation points of departure (PODs) were selected for pyriproxyfen and there are no long-term inhalation exposure scenarios for the registered uses of pyriproxyfen, the only exposure scenarios are for post-application incidental oral exposures for children 1 to less than 2 years old (1 to <2 years old) for all durations of exposure and long-term dermal exposures for children 1 to <2 years old and adults. Residential post-application short-, intermediate-, and long-term incidental oral risk estimates from contact with treated lawns, treated indoor areas and contact with pets treated with shampoo and spot-on applications to pets for children 1 to <2 years old result in no risks of concern (*i.e.,* all margins of exposure (MOEs) are greater than the LOC (> LOC of 100); MOEs range from 4,700 to 9,000,000.

With use of chemical-specific dust torsion exposure data for pyriproxyfen pet collars, long-term combined (dermal + incidental oral) risk estimates for children 1 to <2 years old also result in no risks of concern (*i.e.,* all combined MOEs are >100); MOEs range from 570 to 2,300. Further, long-term adult dermal risks are not of concern; MOEs range from 1,600 to 6,400.

Cumulative exposures. Section 408(b)(2)(D)(v) of FFDCA requires that, when considering whether to establish, modify, or revoke a tolerance, the Agency consider ''available information'' concerning the cumulative effects of a particular pesticide's residues and ''other substances that have a common mechanism of toxicity.'' EPA's assessment of cumulative exposures has not changed since the February 22, 2016 rulemaking (81 FR 8658) (FRL–9941–68). Unlike other pesticides for which EPA has followed a cumulative risk approach based on a common mechanism of toxicity, EPA has not found a common mechanism of toxicity as to pyriproxyfen and any other substances and pyriproxyfen does not appear to produce a toxic metabolite produced by other substances. For the purposes of this action, therefore, EPA has not assumed that pyriproxyfen has a common mechanism of toxicity with other substances.

Safety factor for infants and children. The scientific information underpinning EPA's prior safety factor determination remains unchanged from the February 22, 2016 rulemaking (81 FR 8658) (FRL–9941–68). Therefore, EPA continues to conclude that there is reliable data to support the reduction of the Food Quality Protection Act (FQPA) safety

factor for pyriproxyfen. See Unit III.D. of the February 22, 2016 rulemaking for a discussion of the Agency's rationale for that determination.

IV. Aggregate Risks and Determination of Safety

EPA determines whether acute and chronic dietary pesticide exposures are safe by comparing dietary exposure estimates to the acute population adjusted dose (aPAD) and the cPAD. Short-, intermediate-, and chronic-term risks are evaluated by comparing the estimated aggregate food, water, and residential exposure to the appropriate points of departure to ensure that an adequate margin of exposure (MOE) exists. For linear cancer risks, EPA calculates the lifetime probability of acquiring cancer given the estimated aggregate exposure.

Acute risk. An acute dietary risk assessment was not conducted because an acute endpoint could not be established.

Short-term and Intermediate-term risk. The short- and intermediate-term aggregate risk assessment remains unchanged from the 2017 draft human health risk assessment for *Registration Review.*

Chronic risk. In aggregating chronic risk, EPA considered background chronic dietary exposure (food + drinking water) and long-term residential combined (dermal + incidental oral) children 1 to <2 years old exposures from contact with small dogs treated with a pyriproxyfen collar. The chronic dietary (food + drinking water) exposures were estimated at 5.8% of the cPAD for the U.S. general population and 15% of the cPAD for the most highly exposed population subgroup (children 1–2 years old) and are below EPA's LOC (<100% cPAD). The total long-term dietary and residential aggregate (incidental oral + dermal) MOE is 320 for children 1 to <2 years. The total long-term dietary and residential aggregated (dermal) MOE is 1,000 for adults. As all these MOEs are greater than 100, the chronic aggregate risk is not of concern.

Aggregate cancer risk for U.S. population. Pyriproxyfen is classified as having no evidence for carcinogenicity to humans, based on the absence of evidence of carcinogenicity in male and female rats as well as in male and female mice. Therefore, cancer risk is not a concern and cancer risks are not quantified.

Based on the risk assessments and information described above, EPA concludes there is a reasonable certainty that no harm will result to the U.S. general population, or to infants and children, from aggregate exposure to pyriproxyfen residues. More detailed information on the subject action to establish tolerances in or on egg; poultry, fat; poultry, meat; and poultry, meat byproducts can be found at *http://www.regulations.gov* in the document entitled ''Pyriproxyfen. Human Health Risk Assessment for Establishment of Permanent Tolerances in Egg and Poultry Tissue and Amendment to Remove Restrictions Against the Presence of Animals in Poultry Houses During Premise Treatment,'' dated September 15, 2021. This document can be found in docket ID number EPA–HQ–OPP–2020–0512.

V. Other Considerations

A. Analytical Enforcement Methodology

For a discussion of the available analytical enforcement method, see Unit IV.A. of the February 22, 2016 rulemaking (81 FR 8658) (FRL–9941–68).

B. International Residue Limits

In making its tolerance decisions, EPA seeks to harmonize U.S. tolerances with international standards whenever possible, consistent with U.S. food safety standards and agricultural practices. EPA considers the international maximum residue limits (MRLs) established by the Codex Alimentarius Commission (Codex), as required by FFDCA section 408(b)(4).

No Codex maximum residue limits (MRLs) have been established for residues of pyriproxyfen in/on the proposed commodities in this action. Canada has a default tolerance of 0.1 ppm on egg and poultry tissue.

C. Revisions to Petitioned-For Tolerances

The proposed amended use involves the establishment of permanent tolerances of pyriproxyfen in/on poultry egg and tissue. While OECD calculations procedures determined overall tolerances to be 0.03 ppm for poultry egg, muscle and liver, and 0.04 ppm for poultry fat, there is already an existing tolerance of 0.1 ppm under 40 CFR 180.510(a)(2) for FHE. EPA believes it would be inappropriate to set tolerances in/on poultry egg and tissue commodities below the currently established FHE tolerance. EPA is establishing tolerances of 0.1 ppm for residues in/on egg and poultry tissue under a new listing in the CFR (*i.e.,* 40 CFR 180.510 (a)(3)) for residues of pyriproxyfen and its metabolite 4′-OH-Pyr (free and conjugated), which would account for additional pyriproxyfen residues that could result from any subsequent FHE use of pyriproxyfen, as well as negligible residues on feed. For egg and poultry tissue, the proposed tolerance of 0.1 ppm is equal to the FHE tolerance and would be appropriate and protective.

Additionally, based upon review of the data supporting the petition as submitted by the petitioner, EPA recommends revisions to the commodity definitions in section G of the petition to specify poultry, fat; poultry, meat; and poultry, meat byproducts, rather than poultry, tissue.

VI. Conclusion

Tolerances are established for residues of pyriproxyfen, including its metabolites and degradates, in or on egg at 0.1 parts per million (ppm); poultry, fat at 0.1 ppm; poultry, meat at 0.1 ppm; and poultry, meat byproducts at 0.1 ppm.

VII. Statutory and Executive Order Reviews

This action establishes tolerances under FFDCA section 408(d) in response to a petition submitted to the Agency. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Order 12866, entitled ''Regulatory Planning and Review'' (58 FR 51735, October 4, 1993). Because this action has been exempted from review under Executive Order 12866, this action is not subject to Executive Order 13211, entitled ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001) or Executive Order 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997). This action does not contain any information collections subject to OMB approval under the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), nor does it require any special considerations under Executive Order 12898, entitled ''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations'' (59 FR 7629, February 16, 1994).

Since tolerances and exemptions that are established on the basis of a petition under FFDCA section 408(d), such as the tolerance in this final rule, do not require the issuance of a proposed rule, the requirements of the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*), do not apply.

This action directly regulates growers, food processors, food handlers, and food retailers, not states or tribes, nor does this action alter the relationships or

distribution of power and responsibilities established by Congress in the preemption provisions of FFDCA section 408(n)(4). As such, the Agency has determined that this action will not have a substantial direct effect on States or Tribal Governments, on the relationship between the National Government and the States or Tribal Governments, or on the distribution of power and responsibilities among the various levels of government or between the Federal Government and Indian Tribes. Thus, the Agency has determined that Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999) and Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000) do not apply to this action. In addition, this action does not impose any enforceable duty or contain any unfunded mandate as described under Title II of the Unfunded Mandates Reform Act (UMRA) (2 U.S.C. 1501 *et seq.*).

This action does not involve any technical standards that would require Agency consideration of voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 272 note).

VIII. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 180

Environmental protection, Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: November 5, 2021.

Catherine Aubee,

Acting Director, Registration Division, Office of Pesticide Programs.

Therefore, for the reasons stated in the preamble, EPA is amending 40 CFR chapter I as follows:

PART 180—TOLERANCES AND EXEMPTIONS FOR PESTICIDE CHEMICAL RESIDUES IN FOOD

■ 1. The authority citation for part 180 continues to read as follows:

Authority: 21 U.S.C. 321(q), 346a and 371.

■ 2. In § 180.510, designate the table in paragraph (a)(1) as ''Table 1 to Paragraph (a)(1) and amend it by adding in alphabetical order the following commodities ''Egg''; ''Poultry, fat''; ''Poultry, meat''; and ''Poultry, meat byproducts'' to read as follows:

§ 180.510 Pyriproxyfen; tolerances for residues.

(a) * * *

(1) * * *

TABLE 1 TO PARAGRAPH (a)(1)

Commodity	Parts per million
* * * * *	
Egg	0.1
* * * * *	
Poultry, fat	0.1
Poultry, meat	0.1
Poultry, meat byproducts	0.1
* * * * *	

* * * * *

[FR Doc. 2021–24793 Filed 11–12–21; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2020–0481; FRL–8918–01–OCSPP]

Methylorubrum populi Strain NLS0089; Exemption From the Requirement of a Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes an exemption from the requirement of a tolerance for residues of *Methylorubrum populi* strain NLS0089 in or on all food commodities when used in accordance with label directions and good agricultural practices. NewLeaf Symbiotics submitted a petition to EPA under the Federal Food, Drug, and Cosmetic Act (FFDCA), requesting an exemption from the requirement of a tolerance. This regulation eliminates the need to establish a maximum permissible level for residues of *Methylorubrum populi* strain NLS0089 under FFDCA when used in accordance with this exemption.

DATES: This regulation is effective November 15, 2021. Objections and requests for hearings must be received on or before January 14, 2022 and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2020–0481, is available at *https://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW, Washington, DC 20460–0001. 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 OPP Docket is (703) 305–5805.

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FOR FURTHER INFORMATION CONTACT: Charles Smith, Biopesticides and Pollution Prevention Division (7511P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001; main telephone number: (703) 305–7090; email address: *BPPDFRNotices@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of 40 CFR part 180 through the Office of the Federal

Register's e-CFR site at *https://ecfr.federalregister.gov/current/title-40.*

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a(g), any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2020–0481 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing and must be received by the Hearing Clerk on or before January 14, 2022. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b), although EPA strongly encourages those interested in submitting objections or a hearing request to submit objections and hearing requests electronically. *See* Order Urging Electronic Service and Filing (April 10, 2020), *https://www.epa.gov/sites/production/files/2020-05/documents/2020-04-10_-_order_urging_electronic_service_and_filing.pdf.* At this time, because of the COVID–19 pandemic, the judges and staff of the Office of Administrative Law Judges are working remotely and not able to accept filings or correspondence by courier, personal delivery, or commercial delivery, and the ability to receive filings or correspondence by U.S. Mail is similarly limited. When submitting documents to the U.S. EPA Office of Administrative Law Judges (OALJ), a person should utilize the OALJ e-filing system at *https://yosemite.epa.gov/OA/EAB/EAB-ALJ_upload.nsf.*

Although EPA's regulations require submission via U.S. Mail or hand delivery, EPA intends to treat submissions filed via electronic means as properly filed submissions during this time that the Agency continues to maximize telework due to the pandemic; therefore, EPA believes the preference for submission via electronic means will not be prejudicial. If it is impossible for a person to submit documents electronically or receive service electronically, *e.g.,* the person does not have any access to a computer, the person shall so advise OALJ by contacting the Hearing Clerk at (202) 564–6281. If a person is without access to a computer and must file documents by U.S. Mail, the person shall notify the Hearing Clerk every time it files a document in such a manner. The address for mailing documents is U.S. Environmental Protection Agency, Office of Administrative Law Judges, Mail Code 1900R, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA–HQ–OPP–2020–0481, by one of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001.
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Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *https://www.epa.gov/dockets.*

II. Background

In the **Federal Register** of March 22, 2021 (86 FR 15162) (FRL–10021–44), EPA issued a notice pursuant to FFDCA section 408(d)(3), 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide tolerance exemption petition (PP 0F8823) by NewLeaf Symbiotics, 1005 North Warson Rd., Ste. 102, St. Louis, MO 63132. The petition requested that 40 CFR part 180 be amended by establishing an exemption from the requirement of a tolerance for residues of the fungicide *Methylorubrum populi* strain NLS0089 in or on all food commodities. That notice referenced a summary of the petition prepared by the petitioner NewLeaf Symbiotics and available in the docket via *https://www.regulations.gov.* No comments were received on the notice of filing.

III. Final Rule

A. EPA's Safety Determination

Section 408(c)(2)(A)(i) of FFDCA allows EPA to establish an exemption from the requirement of a tolerance (the legal limit for a pesticide chemical residue in or on a food) only if EPA determines that the exemption is ''safe.'' Section 408(c)(2)(A)(ii) of FFDCA defines ''safe'' to mean that ''there is a reasonable certainty that no harm will result from aggregate exposure to the pesticide chemical residue, including all anticipated dietary exposures and all other exposures for which there is reliable information.'' This includes exposure through drinking water and in residential settings but does not include occupational exposure. Pursuant to FFDCA section 408(c)(2)(B), in establishing or maintaining in effect an exemption from the requirement of a tolerance, EPA must take into account the factors set forth in FFDCA section 408(b)(2)(C), which require EPA to give special consideration to exposure of infants and children to the pesticide chemical residue in establishing a tolerance or tolerance exemption and to ''ensure that there is a reasonable certainty that no harm will result to infants and children from aggregate exposure to the pesticide chemical residue. . . .'' Additionally, FFDCA section 408(b)(2)(D) requires that EPA consider ''available information concerning the cumulative effects of [a particular pesticide's] . . . residues and other substances that have a common mechanism of toxicity.''

EPA evaluated the available toxicological and exposure data on *Methylorubrum populi* strain NLS0089 and considered their validity, completeness, and reliability, as well as the relationship of this information to human risk. A full explanation of the data upon which EPA relied and its risk assessment based on those data can be found within the document entitled ''Revised Human Health Risk Assessment of *Methylorubrum populi* strain NLS0089, a New Active Ingredient, in TS601, a new End-Use Product Proposed for Registration, and an Associated Petition Requesting a Tolerance Exemption'' (*Methylorubrum populi* strain NLS0089 Human Health Assessment). This document, as well as other relevant information, is available in the docket for this action as described under **ADDRESSES**.

The available data demonstrated that, with regard to humans, *Methylorubrum populi* strain NLS0089 is not anticipated to be toxic, pathogenic, or infective via any reasonably foreseeable route of exposure.

In an acute pulmonary toxicity/pathogenicity study, four test animals (one male rat and three female rats) treated with *Methylorubrum populi* strain NLS0089 died on days 2 or 3. Three of four of these test animals

exhibited irregular respiration before death, and, upon necropsy, were found to have red mottled lungs and/or fluid-filled intestines. Further, several of the surviving test animals treated with *Methylorubrum populi* strain NLS0089 exhibited abnormal clinical signs through day 4 (*e.g.,* irregular respiration or pale color) and/or had abnormal gross findings upon necropsy up to day 23 (*e.g.,* red mottled lungs and/or enlarged lymph nodes). Body weight and body weight gain were not adversely affected by treatment, and no abnormal clinical signs, mortalities, or gross necropsy findings were seen in the control animals (not treated or treated with inactivated *Methylorubrum populi* strain NLS0089). The abnormal clinical observations, mortalities, and abnormal necropsy findings are likely consistent with and attributed to factors such as anesthesia administration and test substance administration, which was higher than the recommended maximum hazard dose, via the intratracheal route. As a result, these findings are likely attributed to a combination of anesthesia effects and overdosing, which are not indicative of toxicity or relevant to pesticide exposure concerns when used according to label directions and good agricultural practices. Overall, this study established that *Methylorubrum populi* strain NLS0089 is not pathogenic or infective when administered intratracheally at a single dose of 2.93×10^9 colony-forming units (CFU) per test animal and demonstrated a pattern of clearance of *Methylorubrum populi* strain NLS0089 from the blood, cecum contents, and organs of the test animals.

In an acute injection toxicity/pathogenicity study, numerous test animals treated with *Methylorubrum populi* strain NLS0089 and one test animal treated with inactivated *Methylorubrum populi* strain NLS0089 had enlarged spleens upon necropsy up to day 22. There were no adverse effects of mortality, clinical signs, body weight, or body weight gain in any of the test groups. The abnormal necropsy findings likely reflect a physiological response to a blood-borne antigen rather than a toxic effect on the spleen due to the spleen's function of filtering blood of infectious agents. The assay was testing an artificial infection and most likely indicated lymphocytes producing antibodies reacting to the infection, which were filtered by the spleen causing an enlargement. It should be noted that signs of infection, *i.e.,* the spread of the microbial pest control agents (MPCA) across the blood/brain barrier or to other organs not involved with an immune response, were not noted, and there were no other signs of toxin production during exposure. Overall, this study established that *Methylorubrum populi* strain NLS0089 is not pathogenic or infective when administered intravenously at a single dose of 1.21×10^7 CFU per test animal and demonstrated a pattern of clearance of *Methylorubrum populi* strain NLS0089 from the blood, cecum contents, and organs of the test animals.

There may be some dietary and non-occupational exposures to residues of *Methylorubrum populi* strain NLS0089 when used in accordance with label directions and good agricultural practices, which exposures are only slightly more than environmental background levels for a short period of time after application. However, there is not a concern due to the lack of potential for adverse effects. Because there are no threshold levels of concern with the toxicity, pathogenicity, or infectivity of *Methylorubrum populi* strain NLS0089, EPA determined that no additional margin of safety is necessary to protect infants and children as part of the qualitative assessment conducted. Based upon its evaluation in the *Methylorubrum populi* strain NLS0089 Human Health Assessment, which concludes that there are no risks of concern from aggregate exposure to *Methylorubrum populi* strain NLS0089, EPA concludes that there is a reasonable certainty that no harm will result to the U.S. population, including infants and children, from aggregate exposure to residues of *Methylorubrum populi* strain NLS0089.

B. Analytical Enforcement Methodology

An analytical method is not required for *Methylorubrum populi* strain NLS0089 because EPA is establishing an exemption from the requirement of a tolerance without any numerical limitation.

C. Conclusion

Therefore, an exemption from the requirement of a tolerance is established for residues of *Methylorubrum populi* strain NLS0089 in or on all food commodities when used in accordance with label directions and good agricultural practices.

IV. Statutory and Executive Order Reviews

This action establishes a tolerance exemption under FFDCA section 408(d) in response to a petition submitted to EPA. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Order 12866, entitled ''Regulatory Planning and Review'' (58 FR 51735, October 4, 1993). Because this action has been exempted from review under Executive Order 12866, this action is not subject to Executive Order 13211, entitled ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001), or Executive Order 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997). This action does not contain any information collections subject to OMB approval under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.,* nor does it require any special considerations under Executive Order 12898, entitled ''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations'' (59 FR 7629, February 16, 1994).

Since tolerances and exemptions that are established on the basis of a petition under FFDCA section 408(d), such as the tolerance exemption in this action, do not require the issuance of a proposed rule, the requirements of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) do not apply.

This action directly regulates growers, food processors, food handlers, and food retailers, not States or Tribes. As a result, this action does not alter the relationships or distribution of power and responsibilities established by Congress in the preemption provisions of FFDCA section 408(n)(4). As such, EPA has determined that this action will not have a substantial direct effect on States or Tribal Governments, on the relationship between the National Government and the States or Tribal Governments, or on the distribution of power and responsibilities among the various levels of government or between the Federal Government and Indian Tribes. Thus, EPA has determined that Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), and Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), do not apply to this action. In addition, this action does not impose any enforceable duty or contain any unfunded mandate as described under Title II of the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*).

This action does not involve any technical standards that would require EPA's consideration of voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act (15 U.S.C. 272 note).

V. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 180

Environmental protection, Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: October 26, 2021.

Edward Messina,

Director, Office of Pesticide Programs.

Therefore, for the reasons stated in the preamble, EPA is amending 40 CFR chapter I as follows:

PART 180—TOLERANCES AND EXEMPTIONS FOR PESTICIDE CHEMICAL RESIDUES IN FOOD

■ 1. The authority citation for part 180 continues to read as follows:

Authority: 21 U.S.C. 321(q), 346a and 371.

■ 2. Add § 180.1385 to subpart D to read as follows:

§ 180.1385 *Methylorubrum populi* strain NLS0089; exemption from the requirement of a tolerance.

An exemption from the requirement of a tolerance is established for residues of *Methylorubrum populi* strain NLS0089 in or on all food commodities when used in accordance with label directions and good agricultural practices.

[FR Doc. 2021–24794 Filed 11–12–21; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

42 CFR Part 3

Centers for Medicare & Medicaid Services

42 CFR Parts 402, 403, 411, 412, 422, 423, 460, 483, 488, and 493

Office of the Inspector General

42 CFR Part 1003

Office of the Secretary

45 CFR Parts 79, 93, 102, 147, 150, 155, 156, 158, and 160

Administration for Children and Families

45 CFR Part 303

RIN 0991–AC0

Adjustment of Civil Monetary Penalties for Inflation and the Annual Civil Monetary Penalties Inflation Adjustment for 2021

AGENCY: Office of the Assistant Secretary for Financial Resources, Department of Health and Human Services (HHS).

ACTION: Final rule.

SUMMARY: This final rule finalizes the provisions of the September 6, 2016 interim final rule that adjusts for inflation the maximum civil monetary penalty (CMP) amounts for all agencies within the Department of Health and Human Services (HHS) and updates certain agency-specific regulations. It also updates our required annual inflation-related increases to the CMP amounts in our regulations, under the Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015; adds references to new penalty authorities; and reflects technical changes to correct errors.

DATES:

Effective date: This final rule is effective November 15, 2021.

Applicability date: The adjusted civil monetary penalty amounts apply to penalties assessed on or after November 15, 2021, if the violation occurred on or after November 2, 2015.

FOR FURTHER INFORMATION CONTACT: David Dasher, Deputy Assistant Secretary, Office of Acquisitions, Office of the Assistant Secretary for Financial Resources, Room 536–H, Hubert Humphrey Building, 200 Independence Avenue SW, Washington DC 20201; 202–205–0706.

SUPPLEMENTARY INFORMATION:

I. Background

The Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015 (section 701 of Pub. L. 114–74) (the ''2015 Act'') amended the Federal Civil Penalties Inflation Adjustment Act of 1990 (Pub. L. 101–410, 104 Stat. 890 (1990)), which is intended to improve the effectiveness of civil monetary penalties (CMPs) and to maintain the deterrent effect of such penalties, requires agencies to adjust the civil monetary penalties for inflation annually.

The Department of Health and Human Services (HHS) lists the CMP authorities and the amounts administered by all of its agencies in tabular form in 45 CFR 102.3, which was issued in an interim final rule published in the September 6, 2016, **Federal Register** (81 FR 61538). Annual adjustments were subsequently published on February 3, 2017 (82 FR 9175), October 11, 2018 (83 FR 51369), November 5, 2019 (84 FR 59549), and January 17, 2020 (85 FR 2869).

II. Provisions of the Final Rule

A. Finalization of the September 6, 2016 Interim Final Rule

In the September 6, 2016 **Federal Register** (81 FR 61538), HHS issued a department-wide interim final rule (IFR) titled ''Adjustment of Civil Monetary Penalties for Inflation'' that established new regulations at 45 CFR part 102 to adjust for inflation the maximum CMP amounts for the various CMP authorities for all agencies within the Department. HHS took this action to comply with the Federal Civil Penalties Inflation Adjustment Act of 1990 (the Inflation Adjustment Act) (28 U.S.C. 2461 note 2(a)), as amended by the Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015 (section 701 of the Bipartisan Budget Act of 2015, (Pub. L.114–74), enacted on November 2, 2015). In addition, the September 2016 IFR included updates to certain agency-specific regulations to reflect the new provisions governing the adjustment of civil monetary penalties for inflation in 45 CFR part 102.

One of the purposes of the Inflation Adjustment Act was to create a mechanism to allow for regular inflationary adjustments to federal civil monetary penalties. Section 2(b)(1) of the Inflation Adjustment Act. The 2015 amendments removed an inflation update exclusion that previously applied to the Social Security Act as

well as to the Occupational Safety and Health Act. The 2015 amendments also ''reset'' the inflation calculations by excluding prior inflationary adjustments under the Inflation Adjustment Act and requiring agencies to identify, for each penalty, the year and corresponding amount(s) for which the maximum penalty level or range of minimum and maximum penalties was established (that is, originally enacted by Congress) or last adjusted other than pursuant to the Inflation Adjustment Act. In accordance with section 4 of the Inflation Adjustment Act, agencies were required to: (1) Adjust the level of civil monetary penalties with an initial ''catch-up'' adjustment through an interim final rulemaking to take effect by August 1, 2016; and (2) make subsequent annual adjustments for inflation.

In the September 2016 interim final rule, HHS adopted new regulations at 45 CFR part 102 to govern adjustment of civil monetary penalties for inflation. The regulation at 45 CFR 102.1 provides that part 102 applies to each statutory provision under the laws administered by HHS (including the Centers for Medicare & Medicaid Services (CMS)) concerning CMPs, and that the regulations in part 102 supersede existing HHS regulations setting forth CMP amounts. The CMPs and the adjusted penalty amounts administered by all HHS agencies are listed in tabular form in 45 CFR 102.3. In addition to codifying the adjusted penalty amounts identified in § 102.3, the HHS-wide interim final rule included several technical conforming updates to certain agency-specific regulations, including various CMS regulations, to identify their updated information, and incorporate a cross-reference to the location of HHS-wide regulations.

In the September 12, 2017 **Federal Register** (82 FR 42748), CMS published a correcting amendment that corrected a limited number of technical and typographical errors identified in the CMS provisions of the September 6, 2016 IFR.

The Medicare provisions included in the September 2016 IFR are subject to requirements of section 1871(a) of the Social Security Act (the Act) which sets forth certain procedures for promulgating regulations necessary to carry out the administration of the insurance programs under Title XVIII of the Act. Section 1871(a)(3)(A) of the Act requires the Secretary, in consultation with the Director of the Office of Management and Budget (OMB), to establish a regular timeline for the publication of final regulations based on the previous publication of a proposed rule or an interim final rule. In accordance with section 1871(a)(3)(B) of the Act, such timeline may vary among different rules, based on the complexity of the rule, the number and scope of the comments received, and other relevant factors. However, the timeline for publishing the final rule cannot exceed 3 years from the date of publication of the proposed or interim final rule, unless there are exceptional circumstances. After consultation with the Director of OMB, the Secretary published a notice, which appeared in the December 30, 2004 **Federal Register** (69 FR 78442), establishing a general 3-year timeline for publishing Medicare final rules after the publication of a proposed or interim final rule.

Because the conforming changes to the Medicare provisions were part of a larger, omnibus departmental interim final rule, we inadvertently missed setting a target date for the final rule to make permanent the changes to the Medicare regulations in accordance with section 1871(a)(3)(A) of the Act and the procedures outlined in the December 2004 notice. Consistent with section 1871(a)(3)(C) of the Act, we published notices of continuation extending the effectiveness of the technical conforming changes to the Medicare regulations that were implemented through interim final rule and to allow time to publish a final rule (see the January 2, 2020 (85 FR 7) and September 8, 2020 (85 FR 55385) continuation documents). The extended time was needed to allow for coordination between CMS and the Department to issue a final rule and to avoid the potential for confusion between 45 CFR part 102, which established the civil monetary payment amounts, and the Medicare regulations subject to the timing requirements in section 1871(a)(3)(C) of the Act, which would otherwise cause the regulation to revert to the language that was used prior to the Inflation Adjustment Act.

In this final rule, we are finalizing the provisions of the September 6, 2016 IFR without modification. Because the provisions were established via interim final rulemaking, finalizing the provisions is pro forma for all agencies except CMS. Given the statutory requirements specified previously, finalization of the September 2016 IFR permanently establishes the interim final regulatory provisions for the Medicare program.

B. Calculation of Annual Inflation Adjustment

The annual inflation adjustment for each applicable CMP is determined using the percent increase in the Consumer Price Index for all Urban Consumers (CPI–U) for the month of October of the year in which the amount of each CMP was most recently established or modified. In the December 23, 2020, Office of Management and Budget (OMB) Memorandum for the Heads of Executive Agencies and Departments, M–21–10, ''Implementation of the Penalty Inflation Adjustments for 2021, Pursuant to the Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015,'' OMB published the multiplier for the required annual adjustment. The cost-of-living adjustment multiplier for 2021, based on the CPI–U for the month of October 2020, not seasonally adjusted, is 1.01182. The multiplier is applied to each applicable penalty amount that was updated and published for fiscal year (FY) 2020 and is rounded to the nearest dollar.

C. Other Revisions

In addition to the inflation adjustments for 2021, this final rule updates the table in 45 CFR 102.3 to add references to new, applicable civil money penalty authorities that were established or implemented since the publication of the January 17, 2020 update and that are being updated in this rule. The rule also corrects several technical errors to regulatory references in the table and updates descriptions for clarification and accuracy.

First, a CMS final rule, ''Medicare and Medicaid Programs: CY 2020 Hospital Outpatient PPS Policy Changes and Payment Rates and Ambulatory Surgical Center Payment System Policy Changes and Payment Rates. Price Transparency Requirements for Hospitals to Make Standard Charges Public'' (84 FR 65524, November 27, 2019), effective January 1, 2021, finalized a new provision, codified at 45 CFR 180.90. That section establishes CMPs associated with a hospital's noncompliance with price transparency disclosure and display requirements, and the table has been modified to reflect this requirement.

Second, section 3202(b) of the Coronavirus Aid, Relief, and Economic Security Act (CARES Act) (Pub. L. 116–136) added a requirement that each provider of a diagnostic test for COVID–19 make public the cash price for such test on the provider's public internet site, and authorized the Secretary to impose a CMP on a provider that fails to comply. Rulemaking entitled ''Additional Policy and Regulatory Revisions in Response to the COVID–19 Public Health Emergency'' (85 FR 71142, November 6, 2020) implemented this statutory requirement by

establishing a provision at 45 CFR 182.70, allowing for imposition of a CMP, and the table has been modified to reflect this requirement.

Third, in a CMS interim final rule with comment period entitled ''Medicare and Medicaid Programs, Clinical Laboratory Improvement Amendments (CLIA), and Patient Protection and Affordable Care Act; Additional Policy and Regulatory Revisions in Response to the COVID–19 Public Health Emergency'' (85 FR 54873 through 54874, September 2, 2020), CMS established requirements for all CLIA laboratories to report COVID–19 test results to the Secretary in such form and manner, and at such timing and frequency, as the Secretary may prescribe during the COVID–19 Public Health Emergency. Failure to report test results as required results in condition level deficiencies for which CMPs or other penalties may apply. The table has been modified to reflect this requirement. Also in this interim final rule, CMS codified new enforcement requirements at 42 CFR 488.447 establishing CMP amounts that may be imposed against long term care facilities that fail to report COVID–19 related data as required in 42 CFR 483.80(g)(1) and (2). The table has been modified to reflect these requirements.

Finally, the following technical errors were identified and are corrected in the table at 45 CFR 102.3:

- The regulatory reference of 42 CFR. 1003.210(a)(5) implementing 42 U.S.C. 1395cc(g) which was inadvertently omitted from the regulation and is added.
- The two descriptions of 42 U.S.C. 1395dd(d)(1) are revised for more accuracy because penalties for a responsible physician, unlike penalties for a hospital, are not tied to the number of beds in the hospital (see 42 U.S.C. 1395dd(d)(1)(B)).
- The first description tied to 42 U.S.C. 1395mm(i)(6)(B)(i) is revised from ''is such plan'' to ''if such plan''.
- The regulatory references tied to 42 U.S.C. 1395ss(a)(2), (p)(8), (p)(9)(C), (q)(5)(C), (r)(6)(A), (s)(4), (t)(2) incorrectly referred to 42 CFR part 405 and are corrected to refer to 42 CFR part 402.
- The first set of regulatory references tied to 42 U.S.C. 1395ss(p)(8) are expanded to also include 42 CFR 402.105(f)(2), which was inadvertently omitted, and the corresponding description is revised to replace ''any person'' with ''someone other than issuer'' for greater accuracy and clarification.
- The description for the second set of regulatory references tied to 42 U.S.C. 1395ss(p)(8) is revised to replace ''any person'' with ''an issuer'' for greater accuracy and clarification.
- The first set of regulatory references tied to 42 U.S.C. 1395ss(p)(9)(C) are expanded to also include 42 CFR 402.105(f)(3) and (4), which were inadvertently omitted, and the corresponding description is revised to replace ''any person'' with ''someone other than issuer'' for greater accuracy and clarification.
- The description for the second set of regulatory references tied to 42 U.S.C. 1395ss(p)(9)(C) is revised to replace ''any person'' with ''an issuer'' for greater accuracy and clarification.
- The description for 42 U.S.C. 18081(c)(2) is being revised to ''Failure to comply with ACA requirements related to risk adjustment, reinsurance, risk corridors, Exchanges (including QHP standards) and other ACA Subtitle D standards; Penalty for violations of rules or standards of behavior associated with issuer compliance with risk adjustment, reinsurance, risk corridors, Exchanges (including QHP standards) and other ACA Subtitle D standards. (42 U.S.C. 300gg-22(b)(2)(C))'' for greater accuracy and clarification.
- Reference to the existing CMPs authorized under 42 U.S.C. 1395m-1(a) and 42 CFR 414.504(e) for a reporting entity that has failed to report or made a misrepresentation or omission in reporting applicable information was inadvertently omitted from the prior annual updates and the regulation is modified to include this authority and the 2021 adjusted amount. CMS, in separate rulemaking, made the initial catch-up adjustment for this amount in accordance with the 2015 Act on June 23, 2016 (81 FR 41036, 41069) which was $10,017, and noted that subsequent inflationary adjustments would be made to this amount annually.

++ The adjusted amounts applying the multiplier for each year beginning in 2017 through 2020 [1] are as follows:

—The 2017 adjusted amount is $10,181 ($10,017 × 1.01636).

—The 2018 adjusted amount is $10,389 ($10,181 × 1.02041).

—The 2019 adjusted amount is $10,651 ($10,389 × 1.02522).

—The 2020 adjusted amount is $10,839 ($10,651 × 1.01764).

++ The 2021 adjusted amount is calculated by applying the 2021 multiplier to $10,839 and this adjusted amount is reflected in the table of the regulation at 45 CFR 102.3.

III. Statutory and Executive Order Reviews and Waiver of Proposed Rulemaking

The 2015 Act requires Federal agencies to publish annual penalty inflation adjustments notwithstanding section 553 of the Administrative Procedure Act (APA).

Section 4(a) of the 2015 Act directs Federal agencies to publish annual adjustments no later than January 15th of each year thereafter. In accordance with section 553 of the APA, most rules are subject to notice and comment and are effective no earlier than 30 days after publication in the **Federal Register**. However, section 4(b)(2) of the 2015 Act provides that each agency shall make the annual inflation adjustments ''notwithstanding section 553'' of the APA. According to OMB's Memorandum M–21–10, the phrase ''notwithstanding section 553'' in section 4(b)(2) of the 2015 Act means that ''the public procedure the APA generally requires (that is, notice, an opportunity for comment, and a delay in effective date) is not required for agencies to issue regulations implementing the annual adjustment.''

Consistent with the language of the 2015 Act and OMB's implementation guidance, the inflation adjustments set out in this rule is not subject to notice and an opportunity for public comment and will be effective immediately upon publication. Additionally, HHS finds that notice and comment procedures would be impracticable and unnecessary under the APA for making the statutorily required inflation updates to newly established penalty amounts and for the ministerial and technical changes in this rule. In addition, HHS is waiving notice and comment for the non-substantive technical corrections set out in this final rule. HHS finds good cause for issuing these changes as a final rule without prior notice and comment because these changes only update the regulation to add the new CMP authorities that will be adjusted in accordance with the 2015 Act which were implemented since the last update and to add additional technical clarifying edits to descriptions and correcting inadvertent omissions

[1] The published multiplier for 2017 is 1.01636 (M–17–11, Implementation of the 2017 annual adjustment pursuant to the Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, published December 16, 2016); for 2018 it is 1.02041 (M–18–03, Implementation of Penalty Inflation Adjustments for 2018 pursuant to the Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, published December 15, 2017); for 2019 it is 1.02522 (M–19–04, Implementation of Penalty Inflation Adjustments for 2019 pursuant to the Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, published December 14, 2018); and for 2020 it is 1.01764 (M–20–05, Implementation of Penalty Inflation Adjustments for 2020 pursuant to the Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, published December 16, 2019).

and typographical errors. For these same reasons HHS also finds good cause to make the final rule effective upon publication.

Pursuant to OMB Memorandum M–21–10, HHS has determined that the annual inflation adjustment to the civil monetary penalties in its regulations does not trigger any requirements under procedural statutes and Executive Orders that govern rulemaking procedures.

IV. Effective and Applicability Dates

This rule is effective on the date specified in the **DATES** section of this final rule. The adjusted civil monetary penalty amounts apply to penalties assessed on or after date specified in the **DATES** section of this final rule, if the violation occurred on or after November 2, 2015. If the violation occurred before November 2, 2015, or a penalty was assessed before September 6, 2016, the pre-adjustment civil penalty amounts in effect before September 6, 2016, will apply.

List of Subjects in 45 CFR Part 102

Administrative practice and procedure, Penalties.

For reasons discussed in the preamble, the Department of Health and Human Services adopts the interim final rule published September 6, 2016, at 81 FR 61537, as final with the following changes to 45 CFR part 102:

PART 102—ADJUSTMENT OF CIVIL MONETARY PENALTIES FOR INFLATION

■ 1. The authority citation for part 102 continues to read as follows:

Authority: Public Law 101–410, Sec. 701 of Public Law 114–74, 31 U.S.C. 3801–3812.

■ 2. Amend § 102.3 by revising table 1 to read as follows:

§ 102.3 Penalty adjustment and table.

* * * * *

BILLING CODE 4150–24–P

TABLE 1 TO §102.3 -- CIVIL MONETARY PENALTY AUTHORITIES ADMINISTERED BY HHS

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
21 U.S.C.:						
333(b)(2)(A)		FDA	Penalty for violations related to drug samples resulting in a conviction of any representative of manufacturer or distributor in any 10-year period.	2020	107,050	108,315
333(b)(2)(B)		FDA	Penalty for violation related to drug samples resulting in a conviction of any representative of manufacturer or distributor after the second conviction in any 10-year period.	2020	2,184,670	2,210,493
333(b)(3)		FDA	Penalty for failure to make a report required by 21 U.S.C. 353(d)(3)(E) relating to drug samples.	2020	214,097	216,628
333(f)(1)(A)		FDA	Penalty for any person who violates a requirement related to devices for each such violation.	2020	28,914	29,256
		FDA	Penalty for aggregate of all violations related to devices in a single proceeding.	2020	1,927,676	1,950,461
333(f)(2)(A)		FDA	Penalty for any individual who introduces or delivers for introduction into interstate commerce food that is adulterated per 21 U.S.C. 342(a)(2)(B) or any individual who does not comply with a recall order under 21 U.S.C. 350l.	2020	81,284	82,245
		FDA	Penalty in the case of any other person (other than an individual) for such introduction or delivery of adulterated food.	2020	406,419	411,223
		FDA	Penalty for aggregate of all such violations related to adulterated food adjudicated in a single proceeding.	2020	812,837	822,445
333(f)(3)(A)		FDA	Penalty for all violations adjudicated in a single proceeding for any person who violates 21 U.S.C. 331(jj) by failing to submit the certification required by 42 U.S.C. 282(j)(5)(B) or knowingly submitting a false certification; by failing to submit clinical trial information under 42 U.S.C. 282(j); or by submitting clinical trial information under 42 U.S.C. 282(j) that is false or misleading in any particular under 42 U.S.C. 282(j)(5)(D)	2020	12,316	12,462
333(f)(3)(B)		FDA	Penalty for each day any above violation is not corrected after a 30-day period following notification until the violation is corrected.	2020	12,316	12,462
333(f)(4)(A)(i)		FDA	Penalty for any responsible person that violates a requirement of 21 U.S.C. 355(o) (post-marketing studies, clinical trials, labeling), 21 U.S.C. 355(p) (risk evaluation and mitigation (REMS)), or 21 U.S.C. 355-1 (REMS)	2020	307,923	311,563
		FDA	Penalty for aggregate of all such above violations in a single proceeding.	2020	1,231,690	1,246,249
333(f)(4)(A)(ii)		FDA	Penalty for REMS violation that continues after written notice to the responsible person for the first 30-day period (or any portion thereof) the responsible person continues to be in violation.	2020	307,923	311,563
		FDA	Penalty for REMS violation that continues after written notice to responsible person doubles for every 30-day period thereafter the violation continues, but may not exceed penalty amount for any 30-day period.	2020	1,231,690	1,246,249
		FDA	Penalty for aggregate of all such above violations adjudicated in a single proceeding.	2020	12,316,908	12,462,494
333(f)(9)(A)		FDA	Penalty for any person who violates a requirement which relates to tobacco products for each such violation.	2020	17,857	18,068
		FDA	Penalty for aggregate of all such violations of tobacco product requirement adjudicated in a single proceeding.	2020	1,190,433	1,204,504
333(f)(9)(B)(i)(I)		FDA	Penalty per violation related to violations of tobacco requirements.	2020	297,609	301,127
		FDA	Penalty for aggregate of all such violations of tobacco product requirements adjudicated in a single proceeding.	2020	1,190,433	1,204,504
333(f)(9)(B)(i)(II)		FDA	Penalty in the case of a violation of tobacco product requirements that continues after written notice to such person, for the first 30-day period (or any portion thereof) the person continues to be in violation.	2020	297,609	301,127
		FDA	Penalty for violation of tobacco product requirements that continues after written notice to such person shall double for every 30-day period thereafter the violation continues, but may not exceed penalty amount for any 30-day period.	2020	1,190,433	1,204,504
		FDA	Penalty for aggregate of all such violations related to tobacco product requirements adjudicated in a single proceeding.	2020	11,904,335	12,045,044
333(f)(9)(B)(ii)(I)		FDA	Penalty for any person who either does not conduct post-market surveillance and studies to determine impact of a modified risk tobacco product for which the HHS Secretary has provided them an order to sell, or who does not submit a protocol to the HHS Secretary after being notified of a requirement to conduct post-market surveillance of such tobacco products.	2020	297,609	301,127
		FDA	Penalty for aggregate of for all such above violations adjudicated in a single proceeding.	2020	1,190,433	1,204,504

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
333(f)(9)(B)(ii)(II)		FDA	Penalty for violation of modified risk tobacco product post-market surveillance that continues after written notice to such person for the first 30-day period (or any portion thereof) that the person continues to be in violation.	2020	297,609	301,127
		FDA	Penalty for post-notice violation of modified risk tobacco product post-market surveillance shall double for every 30-day period thereafter that the tobacco product requirement violation continues for any 30-day period, but may not exceed penalty amount for any 30-day period.	2020	1,190,433	1,204,504
			Penalty for aggregate above tobacco product requirement violations adjudicated in a single proceeding.	2020	11,904,335	12,045,044
333(g)(1)		FDA	Penalty for any person who disseminates or causes another party to disseminate a direct-to-consumer advertisement that is false or misleading for the first such violation in any 3-year period.	2020	307,923	311,563
			Penalty for each subsequent above violation in any 3-year period.	2020	615,846	623,125
333 note		FDA	Penalty to be applied for violations of 21 U.S.C. 387f(d)(5) or of violations of restrictions on the sale or distribution of tobacco products promulgated under 21 U.S.C. 387f(d) (e.g., violations of regulations in 21 CFR part 1140) with respect to a retailer with an approved training program in the case of a second regulation violation within a 12-month period.	2020	297	301
		FDA	Penalty in the case of a third violation of 21 U.S.C. 387f(d)(5) or of the tobacco product regulations within a 24-month period.	2020	594	601
		FDA	Penalty in the case of a fourth violation of 21 U.S.C. 387f(d)(5) or of the tobacco product regulations within a 24-month period.	2020	2,381	2,409
		FDA	Penalty in the case of a fifth violation of 21 U.S.C. 387f(d)(5) or of the tobacco product regulations within a 36-month period.	2020	5,952	6,022
		FDA	Penalty in the case of a sixth or subsequent violation of 21 U.S.C. 387f(d)(5) or of the tobacco product regulations within a 48-month period as determined on a case-by-case basis.	2020	11,904	12,045
		FDA	Penalty to be applied for violations of 21 U.S.C. 387f(d)(5) or of violations of restrictions on the sale or distribution of tobacco products promulgated under 21 U.S.C. 387f(d) (e.g., violations of regulations in 21 CFR part 1140) with respect to a retailer that does not have an approved training program in the case of the first regulation violation.	2020	297	301
		FDA	Penalty in the case of a second violation of 21 U.S.C. 387f(d)(5) or of the tobacco product regulations within a 12-month period.	2020	594	601
		FDA	Penalty in the case of a third violation of 21 U.S.C. 387f(d)(5) or of the tobacco product regulations within a 24-month period.	2020	1,191	1,205
		FDA	Penalty in the case of a fourth violation of 21 U.S.C. 387f(d)(5) or of the tobacco product regulations within a 24-month period.	2020	2,381	2,409
		FDA	Penalty in the case of a fifth violation of 21 U.S.C. 387f(d)(5) or of the tobacco product regulations within a 36-month period.	2020	5,952	6,022
		FDA	Penalty in the case of a sixth or subsequent violation of 21 U.S.C. 387f(d)(5) or of the tobacco product regulations within a 48-month period as determined on a case-by-case basis.	2020	11,904	12,045
335b(a)		FDA	Penalty for each violation for any individual who made a false statement or misrepresentation of a material fact, bribed, destroyed, altered, removed, or secreted, or procured the destruction, alteration, removal, or secretion of, any material document, failed to disclose a material fact, obstructed an investigation, employed a consultant who was debarred, debarred individual provided consultant services.	2020	453,711	459,074
		FDA	Penalty in the case of any other person (other than an individual) per above violation.	2020	1,814,843	1,836,294
360pp(b)(1)		FDA	Penalty for any person who violates any such requirements for electronic products, with each unlawful act or omission constituting a separate violation.	2020	2,976	3,011
		FDA	Penalty imposed for any related series of violations of requirements relating to electronic products.	2020	1,014,390	1,026,380
42 U.S.C.				2020		
262(d)		FDA	Penalty per day for violation of order of recall of biological product presenting imminent or substantial hazard.	2020	233,313	236,071
263b(h)(3)		FDA	Penalty for failure to obtain a mammography certificate as required.	2020	18,149	18,364
300aa-28(b)(1)		FDA	Penalty per occurrence for any vaccine manufacturer that intentionally destroys, alters, falsifies, or conceals any record or report required.	2020	233,313	236,071
256b(d)(1)(B)(vi)		HRSA	Penalty for each instance of overcharging a 340B covered entity.	2020	5,883	5,953
299c-(3)(d)		AHRQ	Penalty for an establishment or person supplying information obtained in the course of activities for any purpose other than the purpose for which it was supplied.	2020	15,299	15,480
653(l)(2)	45 CFR 303.21(f)	ACF	Penalty for Misuse of Information in the National Directory of New Hires.	2020	1,569	1,588

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
262a(i)(1)	42 CFR 1003.910	OIG	Penalty for each individual who violates safety and security procedures related to handling dangerous biological agents and toxins.	2020	354,859	359,053
		OIG	Penalty for any other person who violates safety and security procedures related to handling dangerous biological agents and toxins.	2020	709,720	718,109
300jj-51		OIG	Penalty per violation for committing information blocking.	2020	1,082,016	1,094,805
1320a-7a(a)	42 CFR 1003.210(a)(1)	OIG	Penalty for knowingly presenting or causing to be presented to an officer, employee, or agent of the United States a false claim.	2020	20,866	21,113
		OIG	Penalty for knowingly presenting or causing to be presented a request for payment which violates the terms of an assignment, agreement, or PPS agreement.	2020	20,866	21,113
	42 CFR 1003.210(a)(2)	OIG	Penalty for knowingly giving or causing to be presented to a participating provider or supplier false or misleading information that could reasonably be expected to influence a discharge decision.	2020	31,300	31,670
	42 CFR 1003.210(a)(3)	OIG	Penalty for an excluded party retaining ownership or control interest in a participating entity.	2020	20,866	21,113
	42 CFR 1003.1010	OIG	Penalty for remuneration offered to induce program beneficiaries to use particular providers, practitioners, or suppliers.	2020	20,866	21,113
	42 CFR 1003.210(a)(4)	OIG	Penalty for employing or contracting with an excluded individual.	2020	20,866	21,113
	42 CFR 1003.310(a)(3)	OIG	Penalty for knowing and willful solicitation, receipt, offer, or payment of remuneration for referring an individual for a service or for purchasing, leasing, or ordering an item to be paid for by a Federal health care program.	2020	104,330	105,563
	42 CFR 1003.210(a)(1)	OIG	Penalty for ordering or prescribing medical or other item or service during a period in which the person was excluded.	2020	20,866	21,113
	42 CFR 1003.210(a)(6)	OIG	Penalty for knowingly making or causing to be made a false statement, omission or misrepresentation of a material fact in any application, bid, or contract to participate or enroll as a provider or supplier.	2020	104,330	105,563
	42 CFR 1003.210(a)(8)	OIG	Penalty for knowing of an overpayment and failing to report and return.	2020	20,866	21,113
	42 CFR 1003.210(a)(7)	OIG	Penalty for making or using a false record or statement that is material to a false or fraudulent claim.	2020	58,832	59,527
	42 CFR 1003.210(a)(9)	OIG	Penalty for failure to grant timely access to HHS OIG for audits, investigations, evaluations, and other statutory functions of HHS OIG.	2020	31,300	31,670
1320a-7a(b)		OIG	Penalty for payments by a hospital or critical access hospital to induce a physician to reduce or limit services to individuals under direct care of physician or who are entitled to certain medical assistance benefits.	2020	5,216	5,278
		OIG	Penalty for physicians who knowingly receive payments from a hospital or critical access hospital to induce such physician to reduce or limit services to individuals under direct care of physician or who are entitled to certain medical assistance benefits.	2020	5,216	5,278
	42 CFR 1003.210(a)(10)	OIG	Penalty for a physician who executes a document that falsely certifies home health needs for Medicare beneficiaries.	2020	10,433	10,556
1320a-7a(o)		OIG	Penalty for knowingly presenting or causing to be presented a false or fraudulent specified claim under a grant, contract, or other agreement for which the Secretary provides funding.	2020	10,176	10,296
		OIG	Penalty for knowingly making, using, or causing to be made or used any false statement, omission, or misrepresentation of a material fact in any application, proposal, bid, progress report, or other document required to directly or indirectly receive or retain funds provided pursuant to grant, contract, or other agreement.	2020	50,882	51,483
		OIG	Penalty for Knowingly making, using, or causing to be made or used, a false record or statement material to a false or fraudulent specified claim under grant, contract, or other agreement.	2020	50,882	51,483
		OIG	Penalty for knowingly making, using, or causing to be made or used, a false record or statement material to an obligation to pay or transmit funds or property with respect to grant, contract, or other agreement, or knowingly conceals or improperly avoids or decreases any such obligation.	2020		
			Maximum for each false record statement		53,231	53772
			Maximum per day		10,646	10,646
		OIG	Penalty for failure to grant timely access, upon reasonable request, to the I.G. for purposes of audits, investigations, evaluations, or other statutory functions of I.G. in matters involving grants, contracts, or other agreements.	2020	15,265	15,445
1320a-7e(b)(6)(A)	42 CFR 1003.810	OIG	Penalty for failure to report any final adverse action taken against a health care provider, supplier, or practitioner	2020	39,811	40,282

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
1320b-10(b)(1)	42 CFR 1003.610(a)	OIG	Penalty for the misuse of words, symbols, or emblems in communications in a manner in which a person could falsely construe that such item is approved, endorsed, or authorized by HHS	2020	10,705	10,832
1320b-10(b)(2)	42 CFR 1003.610(a)	OIG	Penalty for the misuse of words, symbols, or emblems in a broadcast or telecast in a manner in which a person could falsely construe that such item is approved, endorsed, or authorized by HHS	2020	53,524	54,157
1395i-3(b)(3)(B)(ii)(1)	42 CFR 1003.210(a)(11)	OIG	Penalty for certification of a false statement in assessment of functional capacity of a Skilled Nursing Facility resident assessment	2020	2,233	2,259
1395i-3(b)(3)(B)(ii)(2)	42 CFR 1003.210(a)(11)	OIG	Penalty for causing another to certify or make a false statement in assessment of functional capacity of a Skilled Nursing Facility resident assessment	2020	11,160	11,292
1395i-3(g)(2)(A)	42 CFR 1003.1310	OIG	Penalty for any individual who notifies or causes to be notified a Skilled Nursing Facility of the time or date on which a survey is to be conducted	2020	4,465	4,518
1395w-27(g)(2)(A)	42 CFR 1003.410	OIG	Penalty for a Medicare Advantage organization that substantially fails to provide medically necessary, required items and services	2020	40,640	41,120
		OIG	Penalty for a Medicare Advantage organization that charges excessive premiums.	2020	39,811	40,282
		OIG	Penalty for a Medicare Advantage organization that improperly expels or refuses to reenroll a beneficiary.	2020	39,811	40,282
		OIG	Penalty for a Medicare Advantage organization that engages in practice that would reasonably be expected to have the effect of denying or discouraging enrollment.	2020	159,248	161,130
		OIG	Penalty per individual who does not enroll as a result of a Medicare Advantage organization's practice that would reasonably be expected to have the effect of denying or discouraging enrollment.	2020	23,887	24,169
		OIG	Penalty for a Medicare Advantage organization misrepresenting or falsifying information to Secretary.	2020	159,248	161,130
		OIG	Penalty for a Medicare Advantage organization misrepresenting or falsifying information to individual or other entity.	2020	39,811	40,282
		OIG	Penalty for Medicare Advantage organization interfering with provider's advice to enrollee and non-MCO affiliated providers that balance bill enrollees.	2020	39,811	40,282
		OIG	Penalty for a Medicare Advantage organization that employs or contracts with excluded individual or entity.	2020	39,811	40,282
		OIG	Penalty for a Medicare Advantage organization enrolling an individual in without prior written consent.	2020	39,811	40,282
		OIG	Penalty for a Medicare Advantage organization transferring an enrollee to another plan without consent or solely for the purpose of earning a commission.	2020	39,811	40,282
		OIG	Penalty for a Medicare Advantage organization failing to comply with marketing restrictions or applicable implementing regulations or guidance.	2020	39,811	40,282
		OIG	Penalty for a Medicare Advantage organization employing or contracting with an individual or entity who violates 1395w-27(g)(1)(A)-(J).	2020	39,811	40,282
1395w-141(i)(3)		OIG	Penalty for a prescription drug card sponsor that falsifies or misrepresents marketing materials, overcharges program enrollees, or misuse transitional assistance funds	2020	13,910	14,074
1395cc(g)		OIG	Penalty for improper billing by Hospitals, Critical Access Hospitals, or Skilled Nursing Facilities	2020	5,411	5,475
1395dd(d)(1)	42 CFR 1003.510	OIG	Penalty for a hospital with 100 beds or more or responsible physician dumping patients needing emergency medical care.	2020	111,597	112,916
			Penalty for a hospital with less than 100 beds dumping patients needing emergency medical care.	2020	55,800	56,460
1395mm(i)(6)(B)(i)	42 CFR 1003.410	OIG	Penalty for an HMO or competitive medical plan is such plan substantially fails to provide medically necessary, required items or services	2020	55,800	56,460
		OIG	Penalty for HMOs/competitive medical plans that charge premiums in excess of permitted amounts.	2020	55,800	56,460
		OIG	Penalty for an HMO or competitive medical plan that expels or refuses to reenroll an individual per prescribed conditions.	2020	55,800	56,460
		OIG	Penalty for an HMO or competitive medical plan that implements practices to discourage enrollment of individuals needing services in future.	2020	223,196	225,834
		OIG	Penalty per individual not enrolled in a plan as a result of a HMO or competitive medical plan that implements practices to discourage enrollment of individuals needing services in the future.	2020	32,115	32,495
		OIG	Penalty for a HMO or competitive medical plan that misrepresents or falsifies information to the Secretary.	2020	223,196	225,834
		OIG	Penalty for an HMO or competitive medical plan that misrepresents or falsifies information to an individual or any other entity.	2020	55,800	56,460
		OIG	Penalty for failure by HMO or competitive medical plan to assure prompt payment of Medicare risk sharing contracts or incentive plan provisions.	2020	55,800	56,460

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
		OIG	Penalty for HMO that employs or contracts with excluded individual or entity.	2020	51,222	51,827
1395nn(g)(3)	42 CFR 1003.310	OIG	Penalty for submitting or causing to be submitted claims in violation of the Stark Law's restrictions on physician self-referrals	2020	25,820	26,125
1395nn(g)(4)	42 CFR 1003.310	OIG	Penalty for circumvention schemes in violation of the Stark Law's restrictions on physician self-referrals	2020	172,137	174,172
1395ss(d)(1)	42 CFR 1003.1110	OIG	Penalty for a material misrepresentation regarding Medigap compliance policies	2020	10,705	10,832
1395ss(d)(2)	42 CFR 1003.1110	OIG	Penalty for selling Medigap policy under false pretense	2020	10,705	10,832
1395ss(d)(3)(A)(ii)	42 CFR 1003.1110	OIG	Penalty for an issuer that sells health insurance policy that duplicates benefits	2020	48,192	48,762
		OIG	Penalty for someone other than issuer that sells health insurance that duplicates benefits.	2020	28,914	29,256
1395ss(d)(4)(A)	42 CFR 1003.1110	OIG	Penalty for using mail to sell a non-approved Medigap insurance policy	2020	10,705	10,832
1396b(m)(5)(B)(i)	42 CFR 1003.410	OIG	Penalty for a Medicaid MCO that substantially fails to provide medically necessary, required items or services	2020	53,524	54,157
		OIG	Penalty for a Medicaid MCO that charges excessive premiums.	2020	53,524	54,157
		OIG	Penalty for a Medicaid MCO that improperly expels or refuses to reenroll a beneficiary.	2020	214,097	216,628
		OIG	Penalty per individual who does not enroll as a result of a Medicaid MCO's practice that would reasonably be expected to have the effect of denying or discouraging enrollment.	2020	32,115	32,495
		OIG	Penalty for a Medicaid MCO misrepresenting or falsifying information to the Secretary.	2020	214,097	216,628
		OIG	Penalty for a Medicaid MCO misrepresenting or falsifying information to an individual or another entity.	2020	53,524	54,157
		OIG	Penalty for a Medicaid MCO that fails to comply with contract requirements with respect to physician incentive plans.	2020	48,192	48,762
1396r(b)(3)(B)(ii)(I)	42 CFR 1003.210(a)(11)	OIG	Penalty for willfully and knowingly certifying a material and false statement in a Skilled Nursing Facility resident assessment	2020	2,233	2,259
1396r(b)(3)(B)(ii)(II)	42 CFR 1003.210(a)(11)	OIG	Penalty for willfully and knowingly causing another individual to certify a material and false statement in a Skilled Nursing Facility resident assessment	2020	11,160	11,292
1396r(g)(2)(A)(i)	42 CFR 1003.1310	OIG	Penalty for notifying or causing to be notified a Skilled Nursing Facility of the time or date on which a survey is to be conducted	2020	4,465	4,518
1396r-8(b)(3)(B)	42 CFR 1003.1210	OIG	Penalty for the knowing provision of false information or refusing to provide information about charges or prices of a covered outpatient drug	2020	192,768	195,047
1396r-8(b)(3)(C)(i)	42 CFR 1003.1210	OIG	Penalty per day for failure to timely provide information by drug manufacturer with rebate agreement	2020	19,277	19,505
1396r-8(b)(3)(C)(ii)	42 CFR 1003.1210	OIG	Penalty for knowing provision of false information by drug manufacturer with rebate agreement	2020	192,768	195,047
1396t(i)(3)(A)	42 CFR 1003.1310	OIG	Penalty for notifying home and community-based providers or settings of survey	2020	3,855	3,901
11131(c)	42 CFR 1003.810	OIG	Penalty for failing to report a medical malpractice claim to National Practitioner Data Bank	2020	23,331	23,607
11137(b)(2)	42 CFR 1003.810	OIG	Penalty for breaching confidentiality of information reported to National Practitioner Data Bank	2020	23,331	23,607
299b-22(f)(1)	42 CFR 3.404	OCR	Penalty for violation of confidentiality provision of the Patient Safety and Quality Improvement Act	2020	12,919	13,072
	45 CFR 160.404(b)(1)(i) and (ii)	OCR	Penalty for each pre-February 18, 2009 violation of the HIPAA administrative simplification provisions	2020	162	64
			Calendar Year Cap	2020	40,640	41,120
1320(d)-5(a)	45 CFR 160.404(b)(2)(i)(A), (B)	OCR	Penalty for each February 18, 2009 or later violation of a HIPAA administrative simplification provision in which it is established that the covered entity or business associate did not know and by exercising reasonable diligence, would not have known that the covered entity or business associate violated such a provision:	2020		
			Minimum	2020	119	120
			Maximum	2020	59,522	60,226
			Calendar Year Cap	2020	1,785,651	1,806,757
	45 CFR 160.404(b)(2)(ii)(A), (B)	OCR	Penalty for each February 18, 2009 or later violation of a HIPAA administrative simplification provision in which it is established that the violation was due to reasonable cause and not to willful neglect:	2020		
			Minimum	2020	1,191	1,205
			Maximum	2020	59,522	60,226
			Calendar Year Cap	2020	1,785,651	1,806,757
	45 CFR 160.404(b)(2)(iii)(A), (B)	OCR	Penalty for each February 18, 2009 or later violation of a HIPAA administrative simplification provision in which it is established that the violation was due to willful neglect and was corrected during the 30-day period beginning on the first date the covered entity or business associate knew, or, by exercising reasonable diligence, would have known that the violation occurred:	2020		
			Minimum	2020	11,904	12,045
			Maximum	2020	59,522	60,226

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
			Calendar Year Cap	2020	1,785,651	1,806,757
	45 CFR 160.404(b)(2)(iv)(A), (B)	OCR	Penalty for each February 18, 2009 or later violation of a HIPAA administrative simplification provision in which it is established that the violation was due to willful neglect and was not corrected during the 30-day period beginning on the first date the covered entity or business associate knew, or by exercising reasonable diligence, would have known that the violation occurred:	2020		
			Minimum	2020	59,522	60,226
			Maximum	2020	1,785,651	1,806,757
			Calendar Year Cap	2020	1,785,651	1,806,757
42 U.S.C. 300gg-18, 42 U.S.C. 1302	45 CFR 180.90	CMS	Penalty for a hospital's non-compliance with making public standard charges for hospital items and services	2020		
			Per Day (Maximum)	2020	300	304
CARES Act, Pub. L. 116–136, section 3202(b)(2)	(See 85 FR 71142 November 6, 2020)	CMS	Penalty for a provider's non-compliance with price transparency requirements regarding diagnostic tests for COVID–19	2020		-
			Per Day (Maximum)	2020	-	-
263a(h)(2)(B) & 1395w-2(b)(2)(A)(ii)	42 CFR 493.1834(d)(2)(i).	CMS	Penalty for a clinical laboratory's failure to meet participation and certification requirements and poses immediate jeopardy:	2020		
			Minimum	2020	6,530	6,607
			Maximum	2020	21,410	21,663
	42 CFR 493.1834(d)(2)(ii).	CMS	Penalty for a clinical laboratory's failure to meet participation and certification requirements and the failure does not pose immediate jeopardy:	2020		
			Minimum	2020	108	109
			Maximum	2020	6,422	6,498
	42 CFR 493.1834(d)(2)(iii)	CMS	Penalty for a clinical laboratory's failure to meet SARS-CoV-2 test reporting requirements:	2020	N/A	
			First day of noncompliance.	2020	N/A	
			Each additional day of noncompliance.	2020	N/A	
300gg-15(f)	45 CFR 147.200(e)	CMS	Failure to provide the Summary of Benefits and Coverage.	2020	1,176	1,190
300gg-18	45 CFR 158.606	CMS	Penalty for violations of regulations related to the medical loss ratio reporting and rebating	2020	118	119
	45 CFR 180.90	CMS	Price against hospital identified by CMS as noncompliant according to 45 CFR 182.50 with respect to price transparency requirements regarding diagnostic tests for COVID-19.	2020		
			Maximum penalty per day	2020	Effective 2021	
1320a-7h(b)(1)	42 CFR 402.105(d)(5) and 403.912(a) and (c)	CMS	Penalty for manufacturer or group purchasing organization failing to report information required under 42 U.S.C. 1320a-7h(a), relating to physician ownership or investment interests:	2020		
			Minimum	2020	1,176	1,190
			Maximum	2020	11,766	11,905
			Calendar Year Cap	2020	176,495	178,581
1320a-7h(b)(2)	42 CFR 402.105(h) and 403.912(b) and (c)	CMS	Penalty for manufacturer or group purchasing organization knowingly failing to report information required under 42 U.S.C. 1320a-7h(a), relating to physician ownership or investment interests:	2020		
			Minimum	2020	11,766	11,905
			Maximum	2020	117,664	119,055
			Calendar Year Cap	2020	1,176,638	1,190,546
		CMS	Penalty for an administrator of a facility that fails to comply with notice requirements for the closure of a facility.	2020	117,664	119,055
1320a-7j(h)(3)(A)	42 CFR 488.446(a)(1), (2), & (3)	CMS	Minimum penalty for the first offense of an administrator who fails to provide notice of facility closure.	2020	588	595
			Minimum penalty for the second offense of an administrator who fails to provide notice of facility closure.	2020	1,766	1,787
			Minimum penalty for the third and subsequent offenses of an administrator who fails to provide notice of facility closure.	2020	3,529	3,571
1320a-8(a)(1)		CMS	Penalty for an entity knowingly making a false statement or representation of material fact in the determination of the amount of benefits or payments related to old-age, survivors, and disability insurance benefits, special benefits for certain World War II veterans, or supplemental security income for the aged, blind, and disabled.	2020	8,606	8,708
			Penalty for violation of 42 U.S.C. 1320a-8(a)(1) if the violator is a person who receives a fee or other income for services performed in connection with determination of the benefit amount or the person is a physician or other health care provider who submits evidence in connection with such a determination.	2020	8,116	8,212

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
1320a-8(a)(3)		CMS	Penalty for a representative payee (under 42 U.S.C. 405(j), 1007, or 1383(a)(2)) converting any part of a received payment from the benefit programs described in the previous civil monetary penalty to a use other than for the benefit of the beneficiary.	2020	6,740	6,820
1320b-25(c)(1)(A)		CMS	Penalty for failure of covered individuals to report to the Secretary and 1 or more law enforcement officials any reasonable suspicion of a crime against a resident, or individual receiving care, from a long-term care facility.	2020	235,328	238,110
1320b-25(c)(2)(A)		CMS	Penalty for failure of covered individuals to report to the Secretary and 1 or more law enforcement officials any reasonable suspicion of a crime against a resident, or individual receiving care, from a long-term care facility if such failure exacerbates the harm to the victim of the crime or results in the harm to another individual.	2020	352,991	357,163
1320b-25(d)(2)		CMS	Penalty for a long-term care facility that retaliates against any employee because of lawful acts done by the employee, or files a complaint or report with the State professional disciplinary agency against an employee or nurse for lawful acts done by the employee or nurse.	2020	235,328	238,110
1395b-7(b)(2)(B)	42 CFR 402.105(g)	CMS	Penalty for any person who knowingly and willfully fails to furnish a beneficiary with an itemized statement of items or services within 30 days of the beneficiary's request.	2020	159	161
1395i-3(h)(2)(B)(ii)(I)	42 CFR 488.408(d)(1)(iii)	CMS	Penalty per day for a Skilled Nursing Facility that has a Category 2 violation of certification requirements:	2020		
			Minimum	2020	112	113
			Maximum	2020	6,695	6,774
	42 CFR 488.408(d)(1)(iv)	CMS	Penalty per instance of Category 2 noncompliance by a Skilled Nursing Facility:	2020		
			Minimum	2020	2,233	2,259
			Maximum	2020	22,320	22,584
	42 CFR 488.408(e)(1)(iii)	CMS	Penalty per day for a Skilled Nursing Facility that has a Category 3 violation of certification requirements:	2020		
			Minimum	2020	6,808	6,888
			Maximum	2020	22,320	22,584
	42 CFR 488.408(e)(1)(iv)	CMS	Penalty per instance of Category 3 noncompliance by a Skilled Nursing Facility:	2020		
			Minimum	2020	2,233	2,259
			Maximum	2020	22,320	22,584
	42 CFR 488.408(e)(2)(ii)	CMS	Penalty per day and per instance for a Skilled Nursing Facility that has Category 3 noncompliance with Immediate Jeopardy:	2020		
			Per Day (Minimum)	2020	6,808	6,888
			Per Day (Maximum)	2020	22,320	22,584
			Per Instance (Minimum)	2020	2,233	2,259
			Per Instance (Maximum)	2020	22,320	22,584
	42 CFR 488.438(a)(1)(i)	CMS	Penalty per day of a Skilled Nursing Facility that fails to meet certification requirements. These amounts represent the upper range per day:	2020		
			Minimum	2020	6,808	6,888
			Maximum	2020	22,320	22,584
	42 CFR 488.438(a)(1)(ii)	CMS	Penalty per day of a Skilled Nursing Facility that fails to meet certification requirements. These amounts represent the lower range per day:	2020		
			Minimum	2020	112	113
			Maximum	2020	6,695	6,774
	42 CFR 488.438(a)(2)	CMS	Penalty per instance of a Skilled Nursing Facility that fails to meet certification requirements:	2020		
			Minimum	2020	2,233	2,259
			Maximum	2020	22,320	22,584
	42 CFR 488.447	CMS	Penalty imposed for failure to comply with infection control weekly reporting requirements at 42 CFR 483.80(g)(1) and (2).	2020		
			First occurrence	2020	1,000	1,012
			Incremental increases for each subsequent occurrence.	2020	500	506
1395l(h)(5)(D)	42 CFR 402.105(d)(2)(i)	CMS	Penalty for knowingly, willfully, and repeatedly billing for a clinical diagnostic laboratory test other than on an assignment-related basis. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 320a-7a(a).)	2020	16,257	16,449
1395l(i)(6)		CMS	Penalty for knowingly and willfully presenting or causing to be presented a bill or request for payment for an intraocular lens inserted during or after cataract surgery for which the Medicare payment rate includes the cost of acquiring the class of lens involved.	2020	4,282	4,333
1395l(q)(2)(B)(i)	42 CFR 402.105(a)	CMS	Penalty for knowingly and willfully failing to provide information about a referring physician when seeking payment on an unassigned basis.	2020	4,098	4,146

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
1395m(a)(11)(A)	42 CFR 402.1(c)(4) and 402.105(d)(2)(ii)	CMS	Penalty for any durable medical equipment supplier that knowingly and willfully charges for a covered service that is furnished on a rental basis after the rental payments may no longer be made. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395m(a)(18)(B)	42 CFR 402.1(c)(5) and 402.105(d)(2)(iii)	CMS	Penalty for any nonparticipating durable medical equipment supplier that knowingly and willfully fails to make a refund to Medicare beneficiaries for a covered service for which payment is precluded due to an unsolicited telephone contact from the supplier. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 320a-7a(a).)	2020	16,257	16,449
1395m(b)(5)(C)	42 CFR 402.1(c)(6) and 402.105(d)(2)(iv)	CMS	Penalty for any nonparticipating physician or supplier that knowingly and willfully charges a Medicare beneficiary more than the limiting charge for radiologist services. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 1320a-7a(a))	2020	16,257	16,449
1395m(h)(3)	42 CFR 402.1(c)(8) and 402.105(d)(2)(vi)	CMS	Penalty for any supplier of prosthetic devices, orthotics, and prosthetics that knowing and willfully charges for a covered prosthetic device, orthotic, or prosthetic that is furnished on a rental basis after the rental payment may no longer be made. (Penalties are assessed in the same manner as 42 U.S.C. 1395m(a)(11)(A), that is in the same manner as 42 U.S.C. 395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395m(j)(2)(A)(iii)		CMS	Penalty for any supplier of durable medical equipment including a supplier of prosthetic devices, prosthetics, orthotics, or supplies that knowingly and willfully distributes a certificate of medical necessity in violation of section 1834(j)(2)(A)(i) of the Act or fails to provide the information required under section 1834(j)(2)(A)(ii) of the Act.	2020	1,722	1,742
1395m(j)(4)	42 CFR 402.1(c)(10) and 402.105(d)(2)(vii)	CMS	Penalty for any supplier of durable medical equipment, including a supplier of prosthetic devices, prosthetics, orthotics, or supplies that knowingly and willfully fails to make refunds in a timely manner to Medicare beneficiaries for series billed other than on as assignment-related basis under certain conditions. (Penalties are assessed in the same manner as 42 U.S.C. 1395m(j)(4) and 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395m-1(a)	42 CFR 414.504(e)	CMS	Penalty for an applicable entity that has failed to report or made a misrepresentation or omission in reporting applicable information with respect to a clinical diagnostic laboratory test.	2020	10,839	10,967
	42 CFR 402.1(c)(31) and 402.105(d)(3)	CMS	Penalty for any person or entity who knowingly and willfully bills or collects for any outpatient therapy services or comprehensive outpatient rehabilitation services on other than an assignment-related basis. (Penalties are assessed in the same manner as 42 U.S.C. 1395m(k)(6) and 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395m(l)(6)	42 CFR 402.1(c)(32) and 402.105(d)(4)	CMS	Penalty for any supplier of ambulance services who knowingly and willfully fills or collects for any services on other than an assignment-related basis. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(b)(18)(B), which is assessed according to 1320a-7a(a).)	2020	16,257	16,449
1395u(b)(18)(B)	42 CFR 402.1(c)(11) and 402.105(d)(2)(viii)	CMS	Penalty for any practitioner specified in Section 1842(b)(18)(C) of the Act or other person that knowingly and willfully bills or collects for any services by the practitioners on other than an assignment-related basis. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395u(j)(2)(B)	42 CFR 402.1(c)	CMS	Penalty for any physician who charges more than 125% for a non-participating referral. (Penalties are assessed in the same manner as 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395u(k)	42 CFR 402.1(c)(12), 402.105(d)(2)(ix), section 1834A(a)(9) of the Act, and 42 CFR 414.504(e)	CMS	Penalty for any physician who knowingly and willfully presents or causes to be presented a claim for bill for an assistant at a cataract surgery performed on or after March 1, 1987, for which payment may not be made because of section 1862(a)(15) of the Act. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395u(l)(3)	42 CFR 402.1(c)(13) and 402.105(d)(2)(x)	CMS	Penalty for any nonparticipating physician who does not accept payment on an assignment-related basis and who knowingly and willfully fails to refund on a timely basis any amounts collected for services that are not reasonable or medically necessary or are of poor quality under 1842(l)(1)(A). (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a.))	2020	16,257	16,449
1395u(m)(3)	42 CFR 402.1(c)(14) and 402.105(d)(2)(xi)	CMS	Penalty for any nonparticipating physician charging more than $500 who does not accept payment for an elective surgical procedure on an assignment related basis and who knowingly and willfully fails to disclose the required information regarding charges and coinsurance amounts and fails to refund on a timely basis any amount collected for the procedure in excess of the charges recognized and approved by the Medicare program. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
1395u(n)(3)	42 CFR 402.1(c)(15) and 402.105(d)(2)(xii)	CMS	Penalty for any physician who knowingly, willfully, and repeatedly bills one or more beneficiaries for purchased diagnostic tests any amount other than the payment amount specified by the Act. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 1320a-7a(a))	2020	16,257	16,449
1395u(o)(3)(B)	42 CFR 414.707(b)	CMS	Penalty for any practitioner specified in Section 1842(b)(18)(C) of the Act or other person that knowingly and willfully bills or collects for any services pertaining to drugs or biologics by the practitioners on other than an assignment-related basis. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(b)(18)(B) and 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395u(p)(3)(A)		CMS	Penalty for any physician or practitioner who knowingly and willfully fails promptly to provide the appropriate diagnosis codes upon CMS or Medicare administrative contractor request for payment or bill not submitted on an assignment-related basis.	2020	4,282	4,333
1395w-3a(d)(4)(A)	42 CFR 414.806	CMS	Penalty for a pharmaceutical manufacturer's misrepresentation of average sales price of a drug, or biologic.	2020	13,910	14,074
1395w-4(g)(1)(B)	42 CFR 402.1(c)(17) and 402.105(d)(2)(xiii)	CMS	Penalty for any nonparticipating physician, supplier, or other person that furnishes physician services not on an assignment-related basis who either knowingly and willfully bills or collects in excess of the statutorily-defined limiting charge or fails to make a timely refund or adjustment. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395w-4(g)(3)(B)	42 CFR 402.1(c)(18) and 402.105(d)(2)(xiv)	CMS	Penalty for any person that knowingly and willfully bills for statutorily defined State-plan approved physicians' services on any other basis than an assignment-related basis for a Medicare/Medicaid dual eligible beneficiary. (Penalties are assessed in the same manner as 42 U.S.C. 1395u(j)(2)(B), which is assessed according to 42 U.S.C. 1320a-7a(a).)	2020	16,257	16,449
1395w-27(g)(3)(A); 1857(g)(3); 1860D-12(b)(3)(E)	42 CFR 422.760(b) and 423.760(b)	CMS	Penalty for each termination determination the Secretary makes that is the result of actions by a Medicare Advantage organization or Part D sponsor that has adversely affected (or has the substantial likelihood of adversely affecting) an individual covered under the organization's contract.	2020	39,811	40,282
1395w-27(g)(3)(B); 1857(g)(3); 1860D-12(b)(3)(E)		CMS	Penalty for each week beginning after the initiation of civil money penalty procedures by the Secretary because a Medicare Advantage organization or Part D sponsor has failed to carry out a contract, or has carried out a contract inconsistently with regulations.	2020	15,925	16,113
1395w-27(g)(3)(D); 1857(g)(3): 1860D-12(b)(3)(E)		CMS	Penalty for a Medicare Advantage organization's or Part D sponsor's early termination of its contract.	2020	147,889	149,637
1395y(b)(3)(C)	42 CFR 411.103(b)	CMS	Penalty for an employer or other entity to offer any financial or other incentive for an individual entitled to benefits not to enroll under a group health plan or large group health plan which would be a primary plan.	2020	9,639	9,753
1395y(b)(5)(C)(ii)	42 CFR 402.1(c)(20) and 402.105(b)(2)	CMS	Penalty for any non-governmental employer that, before October 1, 1998, willfully or repeatedly failed to provide timely and accurate information requested relating to an employee's group health insurance coverage.	2020	1,569	1,588
1395y(b)(6)(B)	42 CFR 402.1(c)(21) and 402.105(a)	CMS	Penalty for any entity that knowingly, willfully, and repeatedly fails to complete a claim form relating to the availability of other health benefits in accordance with statute or provides inaccurate information relating to such on the claim form.	2020	3,443	3,484
1395y(b)(7)(B)(i)		CMS	Penalty for any entity serving as insurer, third party administrator, or fiduciary for a group health plan that fails to provide information that identifies situations where the group health plan is or was a primary plan to Medicare to the HHS Secretary.	2020	1,232	1,247
1395y(b)(8)(E)		CMS	Penalty for any non-group health plan that fails to identify claimants who are Medicare beneficiaries and provide information to the HHS Secretary to coordinate benefits and pursue any applicable recovery claim.	2020	1,232	1,247
1395nn(g)(5)	42 CFR 411.361	CMS	Penalty for any person that fails to report information required by HHS under section 1877(f) of the Act concerning ownership, investment, and compensation arrangements.	2020	20,489	20,731
1395pp(h)	42 CFR 402.1(c)(23) and 402.105(d)(2)(xv)	CMS	Penalty for any durable medical equipment supplier, including a supplier of prosthetic devices, prosthetics, orthotics, or supplies, that knowingly and willfully fails to make refunds in a timely manner to Medicare beneficiaries under certain conditions. (42 U.S.C. 1395(m)(18) sanctions apply here in the same manner, which is under 42 U.S.C.1395u(j)(2) and 1320a-7a(a)).	2020	16,257	16,449
1395ss(a)(2)	42 CFR 402.1(c)(24) and 405.105(f)(1)	CMS	Penalty for any person that issues a Medicare supplemental policy that has not been approved by the State regulatory program or does not meet Federal standards after a statutorily defined effective date.	2020	55,799	56,459
1395ss(d)(3)(A)(vi)(II)	42 CFR 402.1(c)(25) and 402.105(e) and (f)(2)	CMS	Penalty for someone other than issuer that sells or issues a Medicare supplemental policy to beneficiary without a disclosure statement.	2020	28,914	29,256
		CMS	Penalty for an issuer that sells or issues a Medicare supplemental policy without disclosure statement.	2020	48,192	48,762

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
1395ss(d)(3)(B)(iv)		CMS	Penalty for someone other than issuer that sells or issues a Medicare supplemental policy without acknowledgement form.	2020	28,914	29,256
		CMS	Penalty for issuer that sells or issues a Medicare supplemental policy without an acknowledgement form.	2020	48,192	48,762
1395ss(p)(8)	42 CFR 402.1(c)(25) and 402.105(e)	CMS	Penalty for someone other than issuer that sells or issues Medicare supplemental polices after a given date that fail to conform to the NAIC or Federal standards established by statute.	2020	28,914	29,256
	42 CFR 402.1(c)(25) and 402.105(f)(2)	CMS	Penalty for an issuer that sells or issues Medicare supplemental polices after a given date that fail to conform to the NAIC or Federal standards established by statute.	2020	48,192	48,762
1395ss(p)(9)(C)	42 CFR 402.1(c)(26), 402.105(e), 402.105(f)(3), (4)	CMS	Penalty for someone other than issuer that sells a Medicare supplemental policy and fails to make available for sale the core group of basic benefits when selling other Medicare supplemental policies with additional benefits or fails to provide the individual, before selling the policy, an outline of coverage describing benefits.	2020	28,914	29,256
	42 CFR 402.1(c)(26), 402.105(f)(3), (4)	CMS	Penalty for an issuer that sells a Medicare supplemental policy and fails to make available for sale the core group of basic benefits when selling other Medicare supplemental policies with additional benefits or fails to provide the individual, before selling the policy, an outline of coverage describing benefits.	2020	48,192	48,762
1395ss(q)(5)(C)	42 CFR 402.1(c)(27) and 402.105(f)(5)	CMS	Penalty for any person that fails to suspend the policy of a policyholder made eligible for medical assistance or automatically reinstates the policy of a policyholder who has lost eligibility for medical assistance, under certain circumstances.	2020	48,192	48,762
1395ss(r)(6)(A)	42 CFR 402.1(c)(28) and 402.105(f)(6)	CMS	Penalty for any person that fails to provide refunds or credits as required by section 1882(r)(1)(B) of the Act.	2020	48,192	48,762
1395ss(s)(4)	42 CFR 402.1(c)(29) and 402.105(c)	CMS	Penalty for any issuer of a Medicare supplemental policy that does not waive listed time periods if they were already satisfied under a proceeding Medicare supplemental policy, or denies a policy, or conditions the issuances or effectiveness of the policy, or discriminates in the pricing of the policy base on health status or other specified criteria.	2020	20,459	20,701
1395ss(t)(2)	42 CFR 402.1(c)(30) and 402.105(f)(7)	CMS	Penalty for any issuer of a Medicare supplemental policy that fails to fulfill listed responsibilities.	2020	48,192	48,762
1395ss(v)(4)(A)		CMS	Penalty someone other than issuer who sells, issues, or renews a Medigap Rx policy to an individual who is a Part D enrollee.	2020	20,865	21,112
		CMS	Penalty for an issuer who sells, issues, or renews a Medigap Rx policy who is a Part D enrollee.	2020	34,777	35,188
1395bbb(c)(1)	42 CFR 488.725(c)	CMS	Penalty for any individual who notifies or causes to be notified a home health agency of the time or date on which a survey of such agency is to be conducted	2020	4,465	4,518
1395bbb(f)(2)(A)(i)	42 CFR 488.845(b)(2)(iii), (b)(3) - (6), and (d)(1)(ii)	CMS	Maximum daily penalty amount for each day a home health agency is not in compliance with statutory requirements	2020	21,410	21,663
	42 CFR 488.845(b)(3)	CMS	Penalty per day for home health agency's noncompliance (Upper Range):	2020		0
			Minimum	2020	18,198	18,413
			Maximum	2020	21,410	21,663
	42 CFR 488.845(b)(3)(i)	CMS	Penalty for a home health agency's deficiency or deficiencies that cause immediate jeopardy and result in actual harm	2020	21,410	21,663
	42 CFR 488.845(b)(3)(ii)	CMS	Penalty for a home health agency's deficiency or deficiencies that cause immediate jeopardy and result in potential for harm	2020	19,268	19,496
	42 CFR 488.845(b)(3)(iii)	CMS	Penalty for an isolated incident of noncompliance in violation of established HHA policy	2020	18,198	18,413
	42 CFR 488.845(b)(4)	CMS	Penalty for a repeat and/or condition-level deficiency that does not constitute immediate jeopardy, but is directly related to poor quality patient care outcomes (Lower Range):	2020		
			Minimum	2020	3,213	3,251
			Maximum	2020	18,198	18,413
	42 CFR 488.845(b)(5)	CMS	Penalty for a repeat and/or condition-level deficiency that does not constitute immediate jeopardy and that is related predominately to structure or process-oriented conditions (Lower Range):	2020		
			Minimum	2020	1,071	1,084
			Maximum	2020	2,141	2,166
	42 CFR 488.845(b)(6)	CMS	Penalty imposed for instance of noncompliance that may be assessed for one or more singular events of condition-level noncompliance that are identified and where the noncompliance was corrected during the onsite survey:	2020		

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
			Minimum	2020	2,141	2,166
			Maximum	2020	21,410	21,663
			Penalty for each day of noncompliance (Maximum).	2020	21,410	21,663
	42 CFR 488.845(d)(1)(ii)	CMS	Penalty for each day of noncompliance (Maximum)	2020	21,410	21,663
1395eee(e)(6)(B); 1396u-4(e)(6)(B)	42 CFR 460.46	CMS	Penalty for PACE organization that discriminates in enrollment or disenrollment, or engages in any practice that would reasonably be expected to have the effect of denying or discouraging enrollment, on the basis of health status or the need for services:	2020	39,811	40,282
		CMS	For each individual not enrolled as a result of the PACE organization's discrimination in enrollment or disenrollment or practice that would deny or discourage enrollment.	2020		
			Minimum	2020	15,000	15,177
			Maximum	2020	100,000	101,182
		CMS	Penalty for a PACE organization that charges excessive premiums.	2020	39,811	40,282
		CMS	Penalty for a PACE organization misrepresenting or falsifying information to CMS or the State.	2020	159,248	161,130
		CMS	Penalty for any other violation specified in 42 CFR 460.40.	2020	39,811	40,282
1396r(h)(3)(C)(ii)(I)	42 CFR 488.408(d)(1)(iii)	CMS	Penalty per day for a nursing facility's failure to meet a Category 2 Certification:	2020		
			Minimum	2020	112	113
			Maximum	2020	6,695	6,774
	42 CFR 488.408(d)(1)(iv)	CMS	Penalty per instance for a nursing facility's failure to meet Category 2 certification:	2020		
			Minimum	2020	2,233	2,259
			Maximum	2020	22,320	22,584
	42 CFR 488.408(e)(1)(iii)	CMS	Penalty per day for a nursing facility's failure to meet Category 3 certification:	2020		
			Minimum	2020	6,808	6,888
			Maximum	2020	22,320	22,584
	42 CFR 488.408(e)(1)(iv)	CMS	Penalty per instance for a nursing facility's failure to meet Category 3 certification:	2020		
			Minimum	2020	2,233	2,259
			Maximum	2020	22,320	22,584
	42 CFR 488.408(e)(2)(ii)	CMS	Penalty per instance for a nursing facility's failure to meet Category 3 certification, which results in immediate jeopardy:	2020		
			Minimum	2020	2,233	2,259
			Maximum	2020	22,320	22,584
	42 CFR 488.438(a)(1)(i)	CMS	Penalty per day for nursing facility's failure to meet certification (Upper Range):	2020		
			Minimum	2020	6,808	6,888
			Maximum	2020	22,320	22,584
	42 CFR 488.438(a)(1)(ii)	CMS	Penalty per day for nursing facility's failure to meet certification (Lower Range):	2020		
			Minimum	2020	112	113
			Maximum	2020	6,695	6,774
	42 CFR 488.438(a)(2)	CMS	Penalty per instance for nursing facility's failure to meet certification:	2020		
			Minimum	2020	2,233	2,259
			Maximum	2020	22,320	22,584
	42 CFR 488.447	CMS	Penalty imposed for failure to comply with infection control weekly reporting requirements at 42 CFR 483.80(g)(1) and (2)	2020		
			First occurrence (Minimum)	2020	1,000	1,012
			Incremental increases for each subsequent occurrence	2020	500	506
1396r(f)(2)(B)(iii)(I)(c)	42 CFR 483.151(b)(2)(iv) and (b)(3)(iii)	CMS	Grounds to prohibit approval of Nurse Aide Training Program—if assessed a penalty in 1819(h)(2)(B)(i) or 1919(h)(2)(A)(ii) of "not less than $5,000" [Not CMP authority, but a specific CMP amount (CMP at this level) that is the triggering condition for disapproval]	2020	11,160	11,292
1396r(h)(3)(C)(ii)(I)	42 CFR 483.151(c)(2)	CMS	Grounds to waive disapproval of nurse aide training program—reference to disapproval based on imposition of CMP "not less than $5,000" [Not CMP authority but CMP imposition at this level determines eligibility to seek waiver of disapproval of nurse aide training program]	2020	11,160	11,292
1396t(j)(2)(C)		CMS	Penalty for each day of noncompliance for a home or community care provider that no longer meets the minimum requirements for home and community care:	2020		
			Minimum	2020	2	2
			Maximum	2020	19,277	19,505
1396u-2(e)(2)(A)(i)	42 CFR 438.704	CMS	Penalty for a Medicaid managed care organization that fails substantially to provide medically necessary items and services	2020	39,811	40,282
		CMS	Penalty for Medicaid managed care organization that imposes premiums or charges on enrollees in excess of the premiums or charges permitted.	2020	39,811	40,282
		CMS	Penalty for a Medicaid managed care organization that misrepresents or falsifies information to another individual or entity.	2020	39,811	40,282

U.S.C. Section(s)	CFR[1]	HHS Agency	Description[2]	Date of Last Penalty Figure or Adjustment[3]	2020 Maximum Adjusted Penalty (in $)	2021 Maximum Adjusted Penalty[4] (in $)
		CMS	Penalty for a Medicaid managed care organization that fails to comply with the applicable statutory requirements for such organizations.	2020	39,811	40,282
1396u-2(e)(2)(A)(ii)	42 CFR 438.704	CMS	Penalty for a Medicaid managed care organization that misrepresents or falsifies information to the HHS Secretary	2020	159,248	161,130
		CMS	Penalty for Medicaid managed care organization that acts to discriminate among enrollees on the basis of their health status.	2020	159,248	161,130
1396u-2(e)(2)(A)(iv)	42 CFR 438.704	CMS	Penalty for each individual that does not enroll as a result of a Medicaid managed care organization that acts to discriminate among enrollees on the basis of their health status	2020	23,887	24,169
1396u(h)(2)	42 CFR part 441, Subpart I	CMS	Penalty for a provider not meeting one of the requirements relating to the protection of the health, safety, and welfare of individuals receiving community supported living arrangements services	2020	22,320	22,584
1396w-2(c)(1)		CMS	Penalty for disclosing information related to eligibility determinations for medical assistance programs	2020	11,904	12,045
18041(c)(2)	45 CFR 156.805(c)	CMS	Failure to comply with ACA requirements related to risk adjustment, reinsurance, risk corridors, Exchanges (including QHP standards) and other ACA Subtitle D standards; Penalty for violations of rules or standards of behavior associated with issuer compliance with risk adjustment, reinsurance, risk corridors, Exchanges (including QHP standards) and other ACA Subtitle D standards.	2020	162	164
18081(h)(1)(A)(i)(II)	45 CFR 155.285	CMS	Penalty for providing false information on Exchange application	2020	29,416	29,764
18081(h)(1)(B)	45 CFR 155.285	CMS	Penalty for knowingly or willfully providing false information on Exchange application	2020	294,159	297,636
18081(h)(2)	45 CFR 155.260	CMS	Penalty for knowingly or willfully disclosing protected information from Exchange	2020		
		CMS	Minimum	2020	29,416	29,764
		CMS	Maximum	2020	300	304
18041(c)(2)	45 CFR 155.206(i)	CMS	Penalties for violation of applicable Exchange standards by consumer assistance entities in Federally-facilitated Exchanges	2020		
			Maximum (Per Day)	2020	100	101
31 U.S.C.				2020	300	304
1352	45 CFR 93.400(e)	HHS	Penalty for the first time an individual makes an expenditure prohibited by regulations regarding lobbying disclosure, absent aggravating circumstances	2020	20,489	20,731
			Penalty for second and subsequent offenses by individuals who make an expenditure prohibited by regulations regarding lobbying disclosure:	2020		
			Minimum	2020	20,489	20,731
			Maximum	2020	204,892	207,314
		HHS	Penalty for the first time an individual fails to file or amend a lobbying disclosure form, absent aggravating circumstances	2020	20,489	20,731
			Penalty for second and subsequent offenses by individuals who fail to file or amend a lobbying disclosure form, absent aggravating circumstances:	2020		
			Minimum	2020	20,489	20,731
			Maximum	2020	204,892	207,314
	45 CFR part 93, Appendix A	HHS	Penalty for failure to provide certification regarding lobbying in the award documents for all sub-awards of all tiers:	2020		
			Minimum	2020	20,489	20,731
			Maximum	2020	204,892	207,314
		HHS	Penalty for failure to provide statement regarding lobbying for loan guarantee and loan insurance transactions:	2020		
			Minimum	2020	20,489	20,731
			Maximum	2020	204,892	207,314
3801-3812	45 CFR 79.3(a)(1)(iv)	HHS	Penalty against any individual who—with knowledge or reason to know—makes, presents or submits a false, fictitious or fraudulent claim to the Department	2020	10,706	10,833
	45 CFR 79.3(b)(1)(ii)	HHS	Penalty against any individual who—with knowledge or reason to know—makes, presents or submits a false, fictitious or fraudulent claim to the Department	2020	10,706	10,833

[1] Some HHS components have not promulgated regulations regarding their civil monetary penalty-specific statutory authorities.
[2] The description is not intended to be a comprehensive explanation of the underlying violation; the statute and corresponding regulation, if applicable, should be consulted.
[3] Statutory or Inflation Act Adjustment.
[4] The cost of living multiplier for 2021, based on the Consumer Price Index for all Urban Consumers (CPI-U) for the month of October 2020, not seasonally adjusted, is 1.01182, as indicated in OMB Memorandum M-21-10, "Implementation of Penalty Inflation Adjustments for 2021, Pursuant to the Federal Civil Penalties Adjustment Act Improvements Act of 2015" (December 23, 2020).

Dated: November 8, 2021.

Xavier Becerra,

Secretary, Department of Health and Human Services.

[FR Doc. 2021–24672 Filed 11–12–21; 8:45 am]

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DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

42 CFR Part 405

[CMS–3372–F3]

RIN 0938–AT88

Medicare Program; Medicare Coverage of Innovative Technology (MCIT) and Definition of ''Reasonable and Necessary''

AGENCY: Centers for Medicare & Medicaid Services (CMS), Department of Health and Human Services (HHS).

ACTION: Final rule.

SUMMARY: This final rule repeals the ''Medicare Coverage of Innovative Technology (MCIT) and Definition of ''Reasonable and Necessary'' final rule, which was published on January 14, 2021, and was to be effective on December 15, 2021.

DATES: This final rule is effective December 15, 2021.

FOR FURTHER INFORMATION CONTACT: Lori Ashby, (410) 786–6322 or *MCIT@cms.hhs.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

A. January 14, 2021 Final Rule

In the January 14, 2021, **Federal Register**, we published a final rule titled ''Medicare Program; Medicare Coverage of Innovative Technology (MCIT) and Definition of 'Reasonable and Necessary'''(86 FR 2987) (hereinafter referred to as the ''MCIT/R&N final rule''). The MCIT/R&N final rule established a Medicare coverage pathway to provide Medicare beneficiaries nationwide with faster access to recently market authorized medical devices designated as breakthrough by the Food and Drug Administration (FDA). Under the final rule, MCIT would result in 4 years of national Medicare coverage starting on the date of FDA market authorization or a manufacturer chosen date within 2 years thereafter. The MCIT/R&N final rule would also implement regulatory standards to be used in making reasonable and necessary determinations under section 1862(a)(1)(A) of the Social Security Act (the Act) for items and services that are furnished under Medicare Parts A and B.

B. March 2021 Interim Final Rule (IFC) and May 2021 Final Rule To Delay Effective Date

In response to the January 20, 2021, memorandum from the Assistant to the President and Chief of Staff titled ''Regulatory Freeze Pending Review'' (''Regulatory Freeze Memorandum'') (86 FR 7424, January 28, 2021) and guidance on implementation of the memorandum issued by the Office of Management and Budget (OMB) in Memorandum M–21–14 dated January 20, 2021, we determined that a 60-day delay of the effective date of the MCIT/R&N final rule was appropriate to ensure that—

- The rulemaking process was procedurally adequate;
- We properly considered all relevant facts;
- We considered statutory or other legal obligations;
- We had reasonable judgment about the legally relevant policy considerations; and
- We adequately considered public comments objecting to certain elements of the rule, including whether interested parties had fair opportunities to present contrary facts and arguments.

Therefore, in an interim final rule with comment period that went on display at the **Federal Register** and took effect on March 12, 2021 (hereinafter referred to as the ''March 2021 IFC''), and was published in the March 17, 2021, **Federal Register** (86 FR 14542), we—(1) delayed the MCIT/R&N final rule effective date until May 15, 2021 (that is, 60 days after the original effective date of March 15, 2021); and (2) opened a 30-day public comment period on the facts, law, and policy underlying the MCIT/R&N final rule.

Many commenters on the March 2021 IFC supported further delaying the MCIT/R&N final rule. Based upon the public comments, we did not believe that it was in the best interest of Medicare beneficiaries for the MCIT/R&N final rule to become effective on May 15, 2021. Therefore, in a final rule that went on display at the **Federal Register** and took effect on May 14, 2021 (hereinafter referred to as the ''May 2021 final rule''), and was published in the May 18, 2021, **Federal Register** (86 FR 26849), we summarized the comments on the March 2021 IFC and further delayed the MCIT/R&N final rule effective date until December 15, 2021. We explained that the additional delay would provide us an opportunity to address issues raised by stakeholders, especially those related to Medicare patient protections and evidence criteria. We announced that during the delay, we would determine appropriate next steps that are in the best interest of all Medicare stakeholders, and beneficiaries in particular.

C. September 2021 Proposed Rule To Repeal the MCIT/R&N Final Rule

In the September 15, 2021, **Federal Register** (86 FR 51326) (hereinafter referred to as the ''September 2021 proposed rule''), we published a proposed rule that would repeal the January 14, 2021 final rule. The September 2021 proposed rule included a 30-day public comment period on the provisions of the proposed repeal.

II. Provisions of Proposed Regulations and Analysis of and Responses

We received approximately 115 timely items of correspondence in response to the September 2021 proposed rule. Commenters included a broad range of stakeholders, including physicians, professional societies, manufacturers, manufacturer associations, venture capital firms, and patient advocates. In this section of this final rule, we present our proposal to repeal the January 2021 MCIT/R&N final rule, our rationale for the proposal, as well as our summation of and responses to the public comments received.

A. Proposed Repeal of Medicare Coverage of Innovative Technology Policy

CMS developed MCIT in part due to concerns that delays and uncertainty in Medicare coverage slowed innovation and impaired beneficiary access to important new technologies, specifically those designated as breakthrough devices by FDA. In response to these concerns, the rule provided 4 years of expedited coverage to FDA market authorized Breakthrough Devices on the first day of FDA market authorization or a select date up to 2 years after the market authorization date as requested by the device manufacturer. While the final rule did not require manufacturers to develop additional scientific evidence supporting the use of the Breakthrough Devices in the Medicare population, manufacturers were aware that, upon conclusion of MCIT coverage, the existing coverage pathways would be available (that is, reasonable and necessary determinations would be made via claim-by-claim adjudication, local coverage determinations (LCDs), and national coverage determinations (NCDs), which include the coverage

with evidence development pathway). The NCD and LCD development processes include reviews of publicly available clinical evidence to determine whether or not the items or services are reasonable and necessary and would be covered by Medicare.

As we noted in the September 2021 proposed rule, we believe that the finalized MCIT/R&N rule is not in the best interest of Medicare beneficiaries because the rule may provide coverage without adequate evidence that the Breakthrough Device would be a reasonable and necessary treatment for the Medicare patients that have the particular disease or condition that the device is intended to treat or diagnose. We have had a growing concern that the provisions that we established in the MCIT/R&N final rule to protect Medicare patients may not have been sufficient. We received comments on this issue again in our subsequent rules that delayed the effective date. By repealing that rule, we can better address those safety concerns in the future. As commenters have noted, the agency must balance competing interests. Although we continue to be in favor of increasing access to new technologies, we are also mindful that sometimes those devices have unknown or unexpected risks. The Medicare program will need to include adequate safeguards to act in those situations.

While the rule tried to address stakeholder concerns about accelerating coverage of new devices, concerns persist about the availability of clinical evidence on Breakthrough Devices when used in the Medicare population as well as the benefit or risks of these devices with respect to use in the Medicare population upon receipt of coverage. Based on the comments received throughout the development of the MCIT pathway, we do not believe that the final rule as currently drafted is the best way to achieve the goals of MCIT as outlined in the MCIT/R&N final rule, in particular, to more precisely meet the needs Medicare beneficiaries and other stakeholders in a timely fashion. We believe that there are other ways to achieve our stated goals. This may include better utilizing existing pathways or conducting future rulemaking.

As noted in the May 2021 final rule, our prior policies permitted the Medicare program to deny coverage for particular devices if we learned that a particular device may be harmful to Medicare beneficiaries. Specifically, Medicare Administrative Contractors (MACs) could have denied claims under certain circumstances (86 FR 26851, May 18, 2021). Under the MCIT/R&N final rule, this case-specific flexibility would have been removed. While we could remove coverage through the NCD process, we would be able to expeditiously remove a Breakthrough Device from the MCIT coverage pathway for only limited reasons, such as if FDA issued a safety communication or warning letter regarding the Breakthrough Device or removed the marketing authorization for a device. This limitation on our authority is impracticable as it may lead to preventable harm to Medicare beneficiaries and it impedes Medicare's ability to make case-by-case determinations regarding whether a device is reasonable and necessary based on clinical evidence. After reviewing Breakthrough Devices with FDA authorization that would be eligible for MCIT, we no longer believe that CMS should grant full national coverage solely based on Breakthrough Designation. While the FDA reviews a device to ensure it meets the applicable safety and effectiveness standard, there is often limited evidence regarding whether the device is clinically beneficial to Medicare patients. We believe this is a key factor in determining coverage under Medicare. The FDA's focus is the safety and effectiveness profile of devices for the intended population, and while these devices may improve symptoms for some patients, the risk-benefit profile may be different for older patients. Further evidence development is needed to better inform medical decision making generally as well as Medicare coverage under the reasonable and necessary standard.

While the MCIT/R&N final rule would have provided expedited Medicare coverage following market authorization for breakthrough designated devices, there is currently no FDA requirement that Medicare beneficiaries must be included in clinical studies needed for market-authorization. Because the MCIT/R&N final rule also did not require data concerning Medicare beneficiaries to fill this gap in evidence specific to Medicare patients, there is the potential that Medicare would cover devices, even in the absence of data demonstrating that the device is reasonable and necessary for Medicare patients. The FDA definition of a medical device is broad, and includes a wide range of products, such as surgical sutures, joint replacements, blood glucose monitors, stents, and implanted valves. After reviewing FDA-designated Breakthrough Devices that have FDA authorization and eligible for MCIT, CMS has concluded that in treating all breakthrough devices similarly, the MCIT/R&N final rule could establish insufficient beneficiary protections for certain devices. Accordingly, we have determined that repealing the MCIT/R&N final rule and revisiting the policy is in the best interest of Medicare patients.

In response to the March 2021 IFC, several medical device manufacturers suggested that, for inclusion in MCIT, FDA pivotal studies should require inclusion of sufficient numbers of Medicare beneficiaries (86 FR 26851, May 18, 2021). We note that a simple proportional requirement may be insufficient, particularly for studies with the smaller sample sizes that are typical for medical devices; valid statistical conclusions require that clinical studies be sufficiently powered to reliably assess risks and benefits in the Medicare population. Certain proponents of accelerated Medicare coverage have argued that FDA's determination that a product meets applicable safety and effectiveness standards for marketing authorization should be sufficient to support Medicare coverage of Breakthrough Devices. However, after further consideration of all public comments, we no longer agree that the FDA safety and effectiveness standards alone are sufficient to support open-ended Medicare coverage. FDA and CMS act under different statutes that have different goals. The standard for Medicare coverage (that is, a determination that a device is reasonable and necessary for the diagnosis or treatment of illness or injury or to improve the functioning of a malformed body member) is not synonymous with the standards for FDA marketing authorization of devices, which are not specific to the Medicare population. Since we issued the MCIT/R&N final rule, we have a better understanding and a growing realization of the consequences of incorporating FDA standards into Medicare decision making to the degree stated in the final rule. We have fully considered the implications, especially in terms of how this would hamper CMS' ability to address unanticipated harms that may arise in the Medicare population. CMS no longer believes that it is appropriate to grant all FDA market authorized Breakthrough Devices automatic coverage solely based on its Breakthrough Designation. While the FDA reviews devices to ensure they meet applicable safety and effectiveness standards, there is often limited evidence regarding whether the device is clinically beneficial to Medicare patients. As stated earlier, this is an

important consideration in determining the type of coverage under Medicare. For example, when only limited evidence on health outcomes was studied for the Medicare population, it is unclear whether Medicare should cover the device with evidence development or should only provide coverage for certain patients, practitioners, or health care facilities. Immediate, broad, unrestricted Medicare coverage under this circumstance could lead to patient harm. Information specific to Medicare populations is important to better inform medical decision making generally, as well as Medicare coverage under the reasonable and necessary standard. Among other things, FDA conducts premarket review of certain devices to evaluate their safety and effectiveness and determines if they meet the applicable standard to be marketed in the United States. In doing so, FDA relies on scientific and medical evidence that does not necessarily include patients from the Medicare population. In general, under the Medicare statute, CMS is charged with determining whether items and services are reasonable and necessary to diagnose or treat an illness or injury or to improve the functioning of a malformed body member. One consideration for CMS in making national coverage determinations under the reasonable and necessary standard is whether the item/service improves health outcomes for Medicare beneficiaries. For CMS, the evidence base underlying the FDA's decision to approve or clear a device for particular indications for use has been crucial for determining Medicare coverage through the NCD process. CMS looks to the evidence supporting FDA market authorization and the device indications for use for evidence generalizable to the Medicare population, data on improvement in health outcomes, and durability of those outcomes. If there are no data on those elements, it is difficult for CMS to make an evidence-based decision whether the device is reasonable and necessary for the Medicare population.

It is important to determine whether Medicare beneficiaries' health outcomes are improved because these individuals are often older, with multiple comorbidities,[1] and are often underrepresented or not represented in many clinical studies.

1. Evidence Development and Patient Safety

The Medicare national coverage determination process includes a robust review of available clinical evidence and focuses on the Medicare population to make reasonable and necessary determinations. In contrast, the MCIT pathway would establish an expedited 4-year coverage pathway for all Breakthrough Devices that fall under a Medicare benefit category without a specific requirement that the device must demonstrate it is reasonable and necessary for the Medicare population. In general, Medicare patients have more comorbidities and often require additional and higher acuity clinical treatments which may impact the outcomes differently than the patients generally enrolled in early clinical trials. These considerations are often not addressed in the device development process.

When we issued the MCIT/R&N final rule on January 14, 2021, we responded to commenters who suggested that CMS should take a different approach. Some commenters suggested that we should require manufacturers to provide data about Medicare outcomes before providing coverage as reasonable and necessary. Other commenters suggested that we provide incentives to manufacturers to include Medicare beneficiaries in clinical studies, similar to CMS's Coverage with Evidence Development (CED) paradigm, before coverage under section 1862(a)(1)(A) of the Act was allowed (86 FR 2990, January 14, 2021).[2] In response to the March 2021 IFC, additional commenters supported evidence development as part of the requirements to participate in the MCIT pathway. Some commenters noted that some clinical trials that were conducted to support market authorization through the Breakthrough Devices pathway lack data on patients older than 65, patients with disabilities, and patients with end stage renal disease (ESRD). They asserted that the absence of this clinical information poses some uncertainty about whether FDA's determination of safety and efficacy could be generalized to the Medicare population (86 FR 26850 and 26851, May 18, 2021).

In response to commenters' concerns about expedited coverage without adequate evidentiary support, CMS agrees that guaranteeing coverage for all Breakthrough Devices receiving market authorization for any Medicare patient could be problematic if there is insufficient evidence demonstrating a health benefit or addressing the additional risks for Medicare beneficiaries (86 FR 26850 and 26851, May 18, 2021). We noted that a Breakthrough Device may only be beneficial in a subset of the Medicare population or when used only by clinicians within a certain specialty to ensure benefit. Without additional clinical evidence on the device's clinical utility for the Medicare population or appropriate providers, it is challenging to determine appropriate Medicare coverage of newly market-authorized Breakthrough Devices (86 FR 26850 and 26851, May 18, 2021).

We recognize that the breakthrough designation may be granted by FDA before sufficient clinical evidence is available to prove there is a health benefit for Medicare patients. FDA has explained in guidance that because decisions on requests for breakthrough designation will be made prior to marketing authorization, FDA considers whether there is a ''reasonable expectation that a device could provide for more effective treatment or diagnosis relative to the current standard of care (SOC) in the U.S'' for purposes of the designation. This reasonable expectation can be ''supported by literature or preliminary data (bench, animal, or clinical)''.[3] Without sufficient evidence developed to show the device improves health outcomes for Medicare beneficiaries, it may be challenging for the Medicare program to determine the health benefit of these devices for Medicare beneficiaries. Public comments expressed concern about how the Medicare population is often excluded from clinical trials due to age and health status.

Previously, in the MCIT/R&N final rule, we noted that ''device coverage under the MCIT pathway is reasonable and necessary for a duration of time under section 1862(a)(1)(A) of the Act because the device has met the very unique criteria of the FDA Breakthrough Devices Program'' (86 FR 2988, January

[1] Davide L Vetrano, M.D., Katie Palmer, Ph.D., Alessandra Marengoni, M.D., Ph.D., Emanuele Marzetti, M.D., Ph.D., Fabrizia Lattanzio, M.D., Ph.D., Regina Roller-Wirnsberger, M.D., MME, Luz Lopez Samaniego, Ph.D., Leocadio Rodríguez-Mañas, M.D., Ph.D., Roberto Bernabei, M.D., Graziano Onder, M.D., Ph.D., Frailty and Multimorbidity: A Systematic Review and Meta-analysis, *The Journals of Gerontology: Series A,* Volume 74, Issue 5, May 2019, Pages 659–666, *https://doi.org/10.1093/gerona/gly110.*

[2] CMS, Guidance for the Public, Industry, and CMS Staff Coverage with Evidence Development, available at *https://www.cms.gov/medicare-coverage-database/details/medicare-coverage-document-details.aspx?MCDId=27.*

[3] Food and Drug Administration, Breakthrough Devices Program Guidance for Industry and Food and Drug Administration Staff, 9, available at: *https://www.fda.gov/media/108135/download.*

14, 2021).[4] Through further consideration of the breakthrough designation process, we have changed our position on this issue and determined that Breakthrough Device designation is not, by itself, sufficient for expedited Medicare coverage purposes. Rather, as explained previously, we understand that FDA may grant a device breakthrough designation when the device has shown a ''reasonable expectation'' of providing more effective treatment or diagnosis of a life-threatening or irreversibly debilitating disease or condition relative to the current U.S. SOC and that it meets the other criterion for designation in section 515B(b)(2) of the Federal Food, Drug, and Cosmetic Act (FD&C) Act (21 U.S.C. 360e-3(b)(2)). CMS acknowledges that we have changed our position on this issue after further consideration of public comments and after considering the full range of FDA designated Breakthrough Devices from diagnostic laboratory tests to implanted valves. As noted previously, we do not believe that granting broad national coverage solely on Breakthrough Device designation alone is in the best interest of beneficiaries or the Medicare program, as this approach does not provide CMS with the necessary flexibility to establish beneficiary safeguards, similar to the patient protections we include in NCDs, specifically CED NCDs, for some of these devices that do not have an evidence base generalizable to the Medicare population. Under the MCIT/R&N final rule, CMS would not be able to include any beneficiary safeguards until the conclusion of the 4-year expedited coverage period and upon completion of an NCD. While we acknowledge that improvements can be made to the existing coverage processes, the inability for CMS to establish beneficiary safeguards under the MCIT/R&N final rule is a significant limitation that can lead to potential beneficiary harm. For these reasons we no longer believe it is in the best interest of Medicare patients to base expedited multiyear, broad national coverage through section 1862(a)(1)(A) of the Act on Breakthrough Device designation alone.

Clinical studies that are conducted in order to gain market authorization for FDA Breakthrough Devices are not required to include information on patients with similar demographics and characteristics of the Medicare population. A potential reason there may not be a strong evidence base specific to the Medicare population could include the desire by device manufacturers to demonstrate the safety and effectiveness of a device as clearly as possible. To achieve this aim, many studies impose stringent exclusion criteria that disqualify individuals with certain characteristics, such as comorbidities and concomitant treatment, that might make the effect of the investigational device more difficult to determine. Consequently, the safety and effectiveness of a device for older patients with more comorbidities may not be well understood at the time of FDA market authorization.

Additionally, there may be devices designated as breakthrough that do not have adequate data on the effectiveness of the device for the Medicare population. Without such evidence, it is possible that Medicare would be covering and paying for devices that may have little or no Medicare relevant clinical evidence to assist physicians and patients in making treatment decisions. Separate from information and evidence submitted for breakthrough designation and market authorization, is the concept of post-market evidence development. Without requiring any evidence development specific to Medicare patients following market authorization, there may not be any evidence to demonstrate whether the device is beneficial after the conclusion of MCIT coverage after 4 years. Evidence-based coverage policy is essential to our objective of improving health outcomes while delivering greater value. Supportive clinical evidence that ensures a device is both safe and effective and reasonable and necessary in the Medicare population is crucial in order to grant coverage for a device under section 1862(a)(1)(A) of the Act. Such evidence is used to determine whether a new technology meets the appropriateness criteria of the longstanding Medicare Program Integrity Manual Chapter 13 definition of reasonable and necessary.[5] We believe that it is important to require manufacturers participating in an innovative coverage pathway, such as MCIT, to produce evidence that demonstrates the health benefit of the device and the related services for patients with demographics similar to that of the Medicare population.

In response to the March 2021 IFC, some commenters cited evidence that FDA-mandated postmarket studies are not reliably completed (less than 20 percent of required studies are completed within 3 to 5 years after market authorization),[6] and asserted that evidence demonstrating a device's health benefit in Medicare beneficiaries is essential. Commenters also recommended that CMS outline in guidance documents the types of evidence that would be acceptable for applications for national or local coverage determinations once the MCIT pathway's 4 years had expired, such as real-world data or randomized, controlled trials (86 FR 26851, May 18, 2021). By voluntarily developing this evidence during the time a device is covered under the MCIT pathway, the manufacturer could have the evidence base needed for one of the other coverage pathways after the MCIT pathway ends. The MCIT/R&N final rule did not require manufacturers of Breakthrough Devices to develop evidence as part of their participation requirements under MCIT. In the May 2021 final rule, we noted that numerous commenters, including physicians with experience in clinical research and medical specialty societies, sought modifications to the MCIT/R&N final rule regarding evidence development, including the addition of real-world evidence requirements. We agree that guidance documents or similar publications outlining the types of evidence that would be acceptable for requests for NCD and LCDs is a good idea. We are continuing to explore additional opportunities to more efficiently publish relevant health outcomes for different disease treatments. CMS is working on the best and most efficient manner to communicate what are important health outcomes. As was noted by commenters in response to the March 2021 IFC, early and unrestricted adoption of devices may have adverse consequences that may not be easy to reverse. CMS expects physicians to consider the available evidence and assess the care needs of each patient when considering the best treatment options. However, by guaranteeing coverage of devices based solely on breakthrough status and FDA marketing authorization, rather than also taking into account whether the device provides an effective, reasonable and necessary treatment for Medicare patients, there may be an incentive for physicians to use a device that has coverage under the MCIT pathway rather than a device that is not covered under the MCIT pathway but is nonetheless covered under an existing coverage pathway and that may be more

[4] 86 FR 2988 (January 14, 2021) *available at https://www.govinfo.gov/content/pkg/FR-2021-01-14/pdf/2021-00707.pdf.*

[5] CMS, Medicare Program Integrity Manual, Chapter 13, 13.5.4, *available at https://www.cms.gov/regulations-and-guidance/guidance/manuals/downloads/pim83c13.pdf*

[6] Rathi et al.

beneficial to patients. We believe that providers' clinical treatment decisions should take the individual needs of the patient into account; therefore, we seek to avoid incentivizing the use of MCIT-covered devices when an alternative item or service may be more appropriate.

While the MCIT/R&N final rule may provide beneficiaries and manufacturers an assurance of national Medicare coverage, evidence development under MCIT as previously finalized is voluntary and there was no requirement that manufacturers conduct studies to generate evidence to demonstrate clinical benefit to Medicare patients. We acknowledge that we no longer believe that voluntary evidence development, as provided for in the MCIT/R&N final rule, is in the best interests of Medicare beneficiaries as we believe such evidence is key to determining the best treatments for Medicare patients to ensure that the benefits of treatments outweigh the potential harms. For devices that lack evidence that is generalizable to the Medicare population, we believe it is important for such evidence to be developed and some public commenters suggested that we establish the coverage criteria (for example, provider experience, site of service, availability of supporting services) to ensure delivery of high-quality, evidence-based care.

While we proposed to repeal the MCIT/R&N final rule, and we now finalize the repeal of the MCIT/R&N rule, this action does not prohibit coverage of Breakthrough Devices. As we noted in the May 2021 final rule, even without the MCIT/R&N final rule in effect, a review of claims data showed that Breakthrough Devices have received and are receiving Medicare coverage when medically necessary. As more Breakthrough Devices achieve market authorization, and as we continue to examine claims data, we are learning that many of the eligible Breakthrough Devices are coverable and payable through existing mechanisms, such as bundled payments. Some Breakthrough Devices may be addressed by an existing LCD or NCD. New items and services can also be adjudicated on a claim-by-claim basis and be covered and paid under the applicable Medicare payment system if the MAC determines them to be reasonable and necessary for specific patients upon a more individualized MAC assessment. The MACs may take into account a beneficiary's particular clinical circumstances to determine whether a beneficiary may benefit from the device. CMS acknowledges, among other factors, that MCIT was developed in response to stakeholder concerns about time lags and coverage uncertainty for devices subject to claim-by-claim coverage determinations. While these paths provide some coverage, it may not meet stakeholders' expectations of faster and more predictable coverage.

2. Limitations of the MCIT Pathway

The MCIT/R&N final rule limited MCIT only to Breakthrough Devices. In accordance with section 515B of the FD&C (21 U.S.C. 360e–3), FDA's Breakthrough Devices Program is for certain medical devices and device-led combination products, and can include lab tests.[7] To be granted a Breakthrough Device designation under the Breakthrough Devices Program, medical devices and device-led combination products must meet two criteria. The first criterion is that the device provides for more effective treatment or diagnosis of life-threatening or irreversibly debilitating human disease or conditions. The second criterion is that the device must satisfy one of the following elements:

- It represents a breakthrough technology.
- No approved or cleared alternatives exist.
- It offers significant advantages over existing approved or cleared alternatives.
- Device availability is in the best interest of patients (for more information see 21 U.S.C. 360e–3(b)(2)).

Some commenters to the September 2020 MCIT/R&N proposed rule expressed concern that the MCIT pathway could give specific technologies an unfair advantage that would be unavailable to subsequent market entrants, thereby decreasing innovation and market competition (86 FR 2998 and 2999). Commenters submitted a variety of alternative approaches to covering second-to-market and non-breakthrough designated new technology to remedy this unintended consequence. Some commenters supported that CMS cover iterative refinements of the same Breakthrough Device for the duration of the original device's MCIT term. Other commenters suggested coverage under the MCIT pathway for subsequent similar breakthrough and non-breakthrough designated devices of the same type and indication for the balance of the first device's MCIT term. Yet other commenters proposed that new market entrants that are very similar to a Breakthrough Device should each receive the full 4 years of MCIT coverage, not tied to the timeline of the original product.

We acknowledge that we have changed our policy position on this issue after further consideration of all public comments received as we have worked to develop the MCIT pathway. We carefully considered the likelihood of reliance by stakeholders, including manufacturers and patients on the MCIT/R&N final rule and our decision to repeal the rule. Because the rule has never gone into effect we believe there has been minimal, if any, reliance on the MCIT/R&N final rule. Further, we believe we can work with stakeholders to achieve appropriate coverage through existing mechanisms. We also agree with commenters that there are many drawbacks to limiting coverage through the MCIT pathway only to those devices that are part of the Breakthrough Devices Program, and we now believe that any future alternative coverage pathway should not include this limitation. As noted previously, the potential incentives created by offering immediate coverage of Breakthrough Devices may disincentivize development of innovative technologies that do not meet the criteria for the Breakthrough Devices Program, such as some non-breakthrough-designated second-to-market devices and subsequent technologies of the same type. Additionally, we now believe a more flexible coverage pathway that leverages existing statutory authorities may be better able to provide faster coverage of new technologies to Medicare beneficiaries while prioritizing patient health and outcomes.

3. Future Coverage Policy Rulemaking

While we proposed to repeal the MCIT/R&N final rule as it is currently written, we considered future policies and potential rulemaking to provide improved access to innovative and beneficial technologies. We are committed to exploring other policy options and statutory authorities for coverage that better suit the needs of Medicare beneficiaries and other stakeholders when the items or services are supported by adequate evidence. For example, we are planning on initiating several coverage process improvements, including engaging the Agency for Healthcare Research and Quality (AHRQ) to explore updating the CED study criteria, as well as exploring options of expediting the NCD process. It is our goal to address these issues in future rulemaking and/or subregulatory guidance.

[7] Breakthrough Devices Program Guidance for Industry and Food and Drug Administration Staff, available at *https://www.fda.gov/media/108135/download.*

Comment: Commenters from multiple stakeholder groups (manufacturers, physicians, associations, etc.) agreed with CMS' proposal to repeal the MCIT/R&N final rule as they believe that the MCIT pathway as originally constructed was flawed and would not achieve the intended outcome of removing delays and uncertainty to improve beneficiary access to innovative technologies.

Response: We appreciate commenters' support for our proposal to repeal the MCIT/R&N final rule. We agree with commenters that while the MCIT/R&N final rule attempted to improve timeliness and predictability of coverage for new technologies, it was flawed in a number of ways that would have prevented predictable, timely coverage for beneficial devices and technologies. We agree with commenters that one of MCIT's limitations is that the MCIT/R&N final rule would have granted up to 4 years of open-ended Medicare coverage for FDA designated Breakthrough Devices upon market authorization, with no conditions of coverage beyond the FDA approved or cleared indication(s) for use. Further, the rule only granted expedited coverage for designated Breakthrough Devices; it did not grant the same coverage to devices or technologies that may treat the same condition but are not FDA designated as a Breakthrough Device, or older devices/technologies that may be more beneficial. This uneven approach to important beneficial devices was concerning and must be addressed.

Comment: Some commenters from multiple stakeholder groups reiterated their concerns that the provision of expedited coverage for certain devices (that is, Breakthrough Devices) without adequate evidence on the Medicare population and no requirement to develop the evidence places beneficiaries at risk of significant harms. Commenters noted that this is especially problematic since Medicare beneficiaries often have comorbidities and may respond differently than other populations that comprise that majority of most clinical trial participants.

Response: We agree that the lack of requirements in the MCIT/R&N final rule for manufacturers to continue to develop evidence demonstrating improved health outcomes in the Medicare population was problematic. When there is a lack of evidence specific to the Medicare population it makes it difficult for CMS to ensure that devices are not posing additional risks in the Medicare population. Continuing to develop evidence generalizable to the Medicare population is important not only to payers, but is key to patients, their caregivers and their treating clinicians to make the most informed decisions for their treatment. We continue to believe that it is important to require manufacturers participating in any innovative coverage pathway, such as MCIT, to produce evidence that demonstrates the health benefit of the device and the related services for patients with demographics similar to that of the Medicare population. It is our intention to address this issue in future rulemaking and we intend to hold at least two stakeholder public meetings in calendar year (CY) 2022 to inform our future policy-making in this space.

Comment: Several commenters noted that CMS already has mechanisms in place to provide coverage of Breakthrough Devices and that the repeal of the MCIT/R&N final rule would not prohibit coverage of these devices.

Response: We appreciate stakeholders' acknowledgement that even without the MCIT pathway, Breakthrough Devices have received and are able to receive Medicare coverage when medically necessary. We also recognize that it is important that stakeholders have transparent, predictable coverage. We are committed to working through this issue as we explore other policy options within our statutory authorities, including future rulemaking. As noted previously, we are planning on initiating several coverage process improvements, including engaging AHRQ to explore updating the CED study criteria, as well as exploring options of expediting the NCD process, and future rulemaking.

Comment: Many commenters indicated that a multitude of revisions would be needed to overcome MCIT's limitations and achieve its intended goals of faster and more predictable Medicare coverage. Commenters cited examples of revisions such as a process that would include benefit category determination (if needed), coding, payment, timeframes for coordinating with FDA, and clinical evidence assessment and development.

Response: We agree that the final MCIT/R&N rule has significant limitations and needs modifications. We will consider these issues as we engage in future rulemaking.

Comment: Some commenters reiterated their concerns that the MCIT/R&N final rule does not specify, nor can it require, coverage criteria beyond the FDA approved or cleared indication(s) for use such as patient criteria and/or provider or facility qualifications or experience. Commenters expressed that clinical trial populations are typically different from the Medicare population, and thus, the evidence supporting those indication(s) for use are less germane to the Medicare population. Without an evidence development requirement pre or post coverage that includes Medicare patients, commenters are concerned about the absence of generalizable clinical evidence. Without information on Medicare patients, commenters are concerned about providers inferring proven performance of breakthrough devices regardless of patient characteristics or facility capabilities.

Response: We appreciate these comments. We will consider these comments as we refine our coverage processes. It is our intention to address this issue in future rulemaking and we intend to hold at least two stakeholder public meetings in CY 2022 to inform our future policy-making in this space.

Comment: There is general agreement among commenters that CMS can address the limitations of the MCIT pathway in future rulemaking. Several commenters recommended that CMS increase efforts to facilitate early engagement among manufacturers, CMS and FDA to discuss suitable trial designs, evidentiary goals, and to ensure that study populations are representative of the Medicare population.

Response: We appreciate the support for our proposal. We will consider all of these comments as we explore other policy options and statutory authorities as we explore future rulemaking to provide appropriate expedited access to innovative and beneficial technologies. We will hold at least two public stakeholder meetings in CY 2022 as we consider several initiatives to improve the coverage process.

Comment: Commenters offered suggestions for CMS to consider in the future as it develops an alternative expedited coverage pathway, including recommendations for how CMS could improve the MCIT pathway and better leverage and improve existing coverage mechanisms, such as parallel review, coverage with evidence development (CED) or the investigational device exemption (IDE) process, in addition to conducting future rulemaking. For example, commenters expressed strong support for CMS to leverage the CED paradigm to provide Medicare beneficiaries with access to new devices and technologies while additional evidence is generated to document a proven benefit for Medicare patients. These commenters noted CMS' past efforts with CED, specifically Transcatheter Aortic Valve Replacement (TAVR), and noted that CMS could require post market studies and data collection through a modified CED

paradigm to ensure that beneficiaries are gaining appropriate access to new technologies that improve health outcomes. Some commenters recommended that CED be time-limited so that the access restrictions that can sometimes accompany CED decisions do not last indefinitely especially in instances when the evidentiary questions of interest have been addressed. Commenters expressed the importance of collecting real world data to fill post-market evidence gaps and encouraged CMS to incorporate such data collection in an improved coverage pathway. These commenters noted that these new technologies need careful monitoring in real world populations.

Response: We appreciate all of the submitted recommendations for CMS to consider as we develop an alternative expedited coverage pathway. It is our intention to address this issue in future rulemaking and we intend to hold at least two stakeholder public meetings in CY 2022 to inform our future policy-making in this space.

Additionally, we currently have a number of initiatives underway to leverage existing coverage mechanisms and inform our efforts to facilitate improvements in coverage pathways. For example, CMS is engaged with the AHRQ to review the current CED study criteria and determine whether the criteria should be revised or updated. Similar to the last CED revision, if a revision is needed, we will use a transparent process that will include public participation such as public comment on any proposed revisions to the CED study criteria, and we will provide as well for public participation in a Medicare Evidence Development and Coverage Advisory Committee (MEDCAC) meeting which CMS will announce a date through a **Federal Register** notice and on the CMS Coverage website. For general information on MEDCAC, please see *https://www.cms.gov/Regulations-and-Guidance/Guidance/FACA/MEDCAC.*

Comment: Many commenters representing a wide-range of stakeholder groups offered additional suggestions on improvements CMS can make to NCDs, including a recommendation that CMS should omit trial design specifications within NCDs and that CMS should address coverage of new indications in NCDs. Some commenters encouraged CMS to review NCD requests and issue NCD implementation instructions within specified timeframes. Several commenters asked that CMS prohibit concurrent NCD and LCD processes.

Response: We appreciate these comments and helpful suggestions offered by commenters on how CMS can improve the NCD process. We will consider these comments as we explore other policy options and statutory authorities to provide appropriate expedited access to innovative and beneficial technologies.

Comment: Several commenters requested that CMS ensure equity between fee-for-service and Medicare Advantage (MA) beneficiaries in an alternative expedited coverage pathway. Some of these commenters noted that MA plans often impose restrictive prior authorization requirements or decline to cover services that are routinely covered and paid for under fee-for-service Medicare, simply due to the absence of a LCD or NCD.

Response: We appreciate these comments and will consider this as we explore other policy options that may help to ensure coverage consistency among Medicare beneficiaries regardless of whether they are enrolled in fee-for-service or MA.

Comment: A few commenters suggested that as CMS takes future action to provide for an alternative expedited coverage pathway, that it provide expedited coverage for a class of devices rather than of a single device to ensure there is not inconsistent or delayed coverage of similar devices or technologies.

Response: We appreciate the comment and will consider this as we explore other policy options. It is our intention to address this issue in future rulemaking and we intend to hold at least two stakeholder public meetings in CY 2022 to inform our future policy-making in this space.

Comment: Some commenters reiterated their concerns that the MCIT pathway has the unintended consequence of limiting access to competitive devices. These commenters recommended that CMS consider broadening the technologies eligible for an expedited coverage pathway to replace MCIT beyond Breakthrough Devices in order to ensure a competitive and innovative marketplace. Several commenters suggested that such an expedited coverage pathway should not only include Breakthrough Devices but also other medical products that are the subject of FDA expedited programs, such as those that receive breakthrough therapy designation or are granted accelerated approval. Commenters specifically requested that screening tests, diagnostics, drugs and biologicals be included.

Response: We appreciate the comments and will further consider these comments as we explore other policy options and statutory authorities.

Comment: As noted previously, some commenters requested that drugs and biological products be included in an alternative expedited coverage pathway as they believe that delayed access to innovative drug and biologic therapies is just as detrimental as delays to innovative devices. However, a few commenters expressed the viewpoint that drugs and biological products not be included as inclusion may lead to unnecessary delays and access issues.

Response: We appreciate the comments and will further consider these comments as we explore other policy options and statutory authorities.

Comment: Several commenters reiterated their concerns that since the MCIT/R&N final rule was solely a coverage rule, a number of operational issues that would inhibit the successful implementation of the MCIT pathway still need to be addressed, including benefit category determination, coding and payment issues. Commenters indicated that the goals of MCIT cannot be achieved until these operational issues are resolved. Several commenters offered suggestions as to how CMS could remedy these issues, including modifications to existing operational processes. For example, these commenters recommended that CMS could adapt the processes used for the IDE, new technology add-on payment (NTAP) and transitional passthrough (TPT) to establish codes and payment for technologies in an expedited coverage pathway. Some commenters requested that any future rulemaking for an alternative expedited coverage pathway include coding and payment information.

Response: We appreciate these comments and agree we should consider all of the operational issues as we work to develop an alternative expedited coverage pathway. We will consider this comment as we initiate coverage process improvements, including engaging AHRQ to explore updating the CED criteria, as well as exploring options of expediting the NCD process, including future rulemaking.

Comment: Several commenters that explicitly stated their opposition to or disappointment with our proposal to repeal the MCIT/R&N final rule provided information and examples specific to their technologies for why an expedited coverage pathway similar to MCIT is needed. These commenters lauded MCIT as a significant advancement in removing delays in national coverage after FDA market authorization and uncertainty in the timing and duration of coverage to improve beneficiary access to innovative technologies.

Response: The majority of the comments citing specific examples of how MCIT is beneficial to its specific technology would likely face the operational challenges because after review of the commenters' devices, it was not clear whether there was a benefit category for the devices. At least one commenter's device would be part of a bundled payment and not separately payable. Because the MCIT/R&N final rule did not address BCD issues, the MCIT/R&N final rule would likely not have resulted in the full coverage they were seeking. We are aware that there is concern when coverage decisions are made at the MAC level, specifically when an LCD is not applicable. This coverage uncertainty may also influence provider decision-making because they are reluctant to submit claims for services that may not be paid for by Medicare.

Comment: A commenter requested that CMS clarify how it intends to approach coverage and payment for prescribed digital therapeutics (PDTs) and include the information in the preamble to this final rule since it had not been addressed in prior MCIT/R&N rulemaking.

Response: We appreciate this comment. However, we are not responding to specific technology evaluations in this final rule as they are out of scope. We will consider this comment as we initiate several coverage process improvements.

Comment: Some commenters stated CMS should allow the MCIT/R&N final rule to go into effect on December 15, 2021, and subsequently issue a proposed rule with appropriate revisions to the MCIT pathway or release subregulatory guidance that addresses the numerous concerns rather than finalizing the repeal.

Response: We appreciate commenters sharing their belief that the rule should go into effect, but we disagree. While we acknowledge that some stakeholders are seeking a replacement pathway simultaneously upon repeal, we need time to more fully evaluate the comments received on the September 2021 proposed rule, and in particular the feedback offered by commenters on how we can improve upon the MCIT pathway.

The final MCIT/R&N rule had major flaws that must be addressed to ensure there is a balance between expedited coverage of devices and patient protections. As we discussed earlier, these flaws also included operational concerns regarding benefit category determinations, coding and payment implementation with expedited coverage. Further, Breakthrough Devices have not necessarily demonstrated a health benefit in the Medicare population. Most importantly, we believe that evidence development must be part of an expedited coverage process, as needed. Based upon these significant concerns with the MCIT pathway, both from the Agency and from several commenters, we believe it is important to move forward with repealing the MCIT/R&N final rule rather than letting it go into effect and modifying it after the fact. We believe that letting the MCIT/R&N final rule go into effect and later modifying it would cause disruptions in health care delivery as there would be confusion and uncertainty among stakeholders, most importantly beneficiaries and their treating clinicians. For example, since the January 2021 MCIT/R&N final rule is a coverage rule only, there could be confusion and disruption stemming from devices receiving MCIT approval without a clear path for appropriate coding and payment. As noted previously, under the January 2021 MCIT/R&N final rule, there is no requirement for evidence that MCIT devices will specifically benefit the Medicare target population. Additionally, the MCIT/R&N final rule limits tools the CMS has to deny coverage when it becomes apparent that a particular device can be harmful to the Medicare population. If the January 2021 MCIT/R&N final rule were to go into effect, and a device is later found to be harmful to Medicare recipients is approved under the MCIT pathway, CMS would be limited in the actions it can take to expeditiously withdraw or modify coverage to protect beneficiaries. Finally, it is not clear that CMS has legal authority under the *Allina* Supreme Court ruling to use subregulatory guidance to modify aspects of the MCIT/R&N final rule as some commenters suggested.

Comment: Of the commenters who disagreed with the proposed rule to repeal the MCIT/R&N rule, most acknowledged the limitations of the MCIT pathway and indicated that modifications were needed, such as the inclusion of coding and payment information and evidentiary standards. A number of these same commenters expressed that while they were disappointed with CMS' proposal to repeal MCIT, they appreciated CMS' ongoing commitment to finding solutions, including an alternative expedited coverage pathway.

Response: We appreciate the comment and will consider the suggested modifications as we move forward.

Comment: Many commenters requested that if CMS were to move forward with repealing the MCIT/R&N final rule, CMS should release a proposed rule offering an alternative expedited coverage pathway simultaneously or as soon as possible thereafter. These commenters requested that CMS provide a timeline for releasing a new rule for an alternative expedited coverage pathway. These commenters noted that an alternative expedited coverage pathway is an urgent need to address the long-standing concerns that Medicare coverage is often slow and unpredictable and impedes beneficiary access to innovative technologies. Some commenters raised concerns that following repeal, CMS would not continue with the forward momentum to create an alternative expedited coverage pathway.

Response: We appreciate these comments. As we move forward with repealing the MCIT/R&N final rule, we want to reassure stakeholders that CMS does not intend to maintain the status quo. We remain committed to our goal of establishing an alternative expedited coverage pathway that better achieve the goals of timely and predictable Medicare coverage of devices while ensuring that Medicare covers items and services on the basis of scientifically sound clinical evidence and with appropriate safeguards. CMS acknowledges that more can be done to address the current uncertainty surrounding Medicare coverage of new medical technologies and while we are unable to provide a specific timeframe for doing so, we are working expeditiously to develop an alternative expedited coverage pathway with adequate patient safeguards to ensure devices are safe for Medicare patients and an evidence base that is generalizable to Medicare beneficiaries is further generated.

Comment: Some commenters stated that CMS has received sufficient public input on potential improvements to MCIT and existing coverage pathways over the course of three public comment periods on the MCIT pathway, other commenters encouraged CMS to conduct town halls to obtain further stakeholder feedback. Numerous commenters expressed willingness to be a resource for CMS as it developed future policies.

Response: Stakeholder engagement is a vitally important component of our efforts to develop an alternative expedited coverage pathway that provides an appropriate balance of innovation and beneficiary protections. We value the diverse viewpoints, perspectives, and options offered by

commenters. As we move forward, we will continue to be open and transparent and will work with stakeholders in efforts to achieve consensus whenever possible.

Even with the repeal of the MCIT/R&N final rule, we have a number of initiatives underway and in development within our existing authorities. These initiatives take into account the feedback CMS has received on the MCIT pathway to date, and we will leverage these initiatives to inform future policy making in this space.

Further, CMS has multiple pathways to facilitate engagement such as the Medicare Evidence Development and Coverage Advisory Committee (MEDCAC) and the public input process through the **Federal Register**. We are also receptive to informal engagement with stakeholders, including with manufacturers who are interested in the development of a new expedited coverage pathway. In addition, we are also exploring other potential avenues to facilitate timely and transparent stakeholder engagement, including listening sessions or town hall meetings, in order to receive additional feedback from stakeholders that can help inform CMS' development of an alternative expedited coverage pathway. In addition, we are initiating coverage process improvements, including engaging AHRQ to explore updating the CED study criteria, as well as exploring options of expediting the NCD process, including future rulemaking.

Comment: Some commenters who disagreed with CMS' proposal to repeal the MCIT/R&N final rule asserted that the patient protections in place in the MCIT/R&N final rule, specifically the reliance on FDA safety and efficacy requirements to grant coverage to Breakthrough Devices under MCIT, were sufficient to prevent beneficiary harm. Some of these commenters stated that CMS will be endangering the patients it is trying to protect if MCIT does not go into effect on December 15, 2021. Some commenters also noted that the data Medicare needs to evaluate a device has already been generated during the FDA approval process.

Response: We disagree that there are sufficient patient protections in the MCIT/R&N final rule. After consideration of all public comments received as we have worked to develop the MCIT pathway, and as we indicated in the September 2021 proposed rule, we no longer believe that FDA safety and effectiveness standards alone are sufficient to support open-ended Medicare coverage. FDA and CMS act under different statutes that have different goals and the standard for Medicare coverage (that is, a determination that a device is reasonable and necessary for the diagnosis or treatment of illness or injury or to improve the functioning of a malformed body member) is not synonymous with the standards for FDA marketing authorization of devices, which are not specific to the Medicare population. CMS acknowledges that we have changed our position on this issue after further consideration of public comments and a review of all FDA-designated Breakthrough Devices eligible for MCIT. As noted previously, granting all eligible FDA-designated Breakthrough Devices national coverage, the MCIT/R&N final rule establishes insufficient beneficiary protections for a subset of devices and must be revised.

Further, we strongly disagree that our repeal of the MCIT/R&N final rule will cause harm to beneficiaries. While there is no guaranteed national coverage that does not mean a given FDA-designated Breakthrough Device is non-covered. CMS' MACs are empowered to make reasonable and necessary coverage determinations on any device where there is not a nationally policy in place, including FDA-designated Breakthrough Devices. We reviewed fee-for-service claims data for several recent market-authorized breakthrough devices. The majority of the FDA market authorized Breakthrough Devices that would have been eligible for the MCIT pathway: Were already paid through an existing mechanism, were directed to a pediatric population, were a diagnostic lab test, were subject to an existing NCD; or had no benefit category or an uncertain benefit category. Of those that would be separately payable by Medicare on a claim-by-claim basis, the reviewed devices were covered when reasonable and necessary and paid under the applicable Medicare payment system. Further, in general, there are typically many treatment options available in the practice of medicine and even if one particular item is not covered, beneficiaries have access to other treatment options.

Comment: Some commenters expressed that beneficiaries and their physicians should be provided with more latitude to assess the advantages and risks of a medical device to treat an individual's specific medical condition.

Response: Patients and their treating clinicians should have latitude to make informed treatment decisions. If we were to guarantee coverage of devices based solely on breakthrough status and FDA marketing authorization, rather than also consider whether the device provides an effective, reasonable and necessary treatment for Medicare patients, there may not be enough information for patients and their treating clinicians to make an adequately informed decision with respect to use of the device for Medicare beneficiaries. Further, there may be an incentive for use of a device that has coverage under the MCIT pathway rather than a device that is not covered under the MCIT pathway which may be more beneficial to patients. This could adversely impact beneficiaries if there is another item or service available to treat the patient that has an evidence-base to suggest that it may lead to better health outcomes for Medicare patients.

Comment: Commenters asserted that the repeal of the MCIT/R&N final rule will undercut evidence development as innovators hold off on study development and enrollment while waiting on CMS to conduct rulemaking with evidentiary standards and other modifications to the MCIT pathway. These commenters also contend that CMS' repeal of the MCIT/R&N final rule could further stifle innovation by undercutting incentives to encourage investment in device development.

Response: Innovation is important to CMS and we strongly encourage innovators to develop reliable evidence to demonstrate that their device is beneficial for Medicare patients. If one of the biggest impediments to innovation is uncertainty, demonstrating with reliable evidence a device's value in treating Medicare patients will largely assist in removing that uncertainty. Ultimately, it is the responsibility of the innovator or manufacturer to demonstrate the value of their device. Evidence development should continue with or without CMS support.

Final Decision: After review of the public comments received, we are finalizing the repeal of the January 2021 MCIT/R&N final rule as proposed in the September 2021 proposed rule without modification.

B. Definition of ''Reasonable and Necessary''

In general, section 1862(a)(1)(A) of the Act permits Medicare payment under Part A or Part B for items or services that are reasonable and necessary for the diagnosis or treatment of illness or injury or to improve the functioning of a malformed body member. The definition of ''reasonable and necessary'' in the MCIT/R&N final rule mirrored the longstanding CMS Program Integrity Manual's definition of ''reasonable and necessary'' with a modification to the appropriateness factor to specify when and how (upon publication of guidance) we would

utilize commercial insurer coverage policies.

Expanding the reasonable and necessary definition to systematically consider commercial insurer coverage presents implementation and appeals process challenges that would likely persist. In the preamble to the MCIT/R&N final rule, in response to commenters concerns that the commercial insurer appropriateness criterion was vague, we stated our intention to gather additional public input on the methodology by which commercial insurers' policies are determined to be relevant to the reasonable and necessary appropriateness criteria. We stated that not later than 12 months after the effective date of the MCIT/R&N final rule (that is, December 15, 2021), we would publish for public comment, a draft methodology for determining when commercial insurers' policies could be considered to meet the reasonable and necessary definition appropriateness criterion for coverage of an item or service. Comments received in response to the March 2021 IFC expressed concern about how the commercial insurer policy provision would be implemented. Commenters also expressed concerns that the R&N definition included in the MCIT/R&N final rule, and more specifically the commercial insurance aspects of the definition, will remove existing flexibilities and potentially impact CMS' ability to ensure equitable health care access for all Medicare beneficiaries. Additionally, commenters suggested that the reasonable and necessary definition should be included in a separate rule as MCIT and R&N are independent and distinct provisions with different implications for Medicare policy. In light of our proposal to repeal the R&N definition, including the commercial insurance aspects of the MCIT/R&N final rule, we will not be issuing subregulatory guidance by March 15, 2022, on consideration of commercial insurer coverage polices when there is insufficient evidence to make a national or local coverage determination.

While we proposed to fully repeal the MCIT/R&N final rule as it is currently written, we invited comments on the R&N aspect of our proposal. In lieu of fully repealing the R&N rule, we considered whether the final rule should instead merely repeal the commercial insurance aspects of the rule. We also asked if CMS does consider future rulemaking to include defining reasonable and necessary, what criteria should CMS consider as part of the reasonable and necessary definition? For example, should CMS maintain the codification of the definition of ''Reasonable and Necessary'' as found in the Chapter 13 of the CMS Program Integrity Manual (PIM) or consider different criteria?

Comment: Most commenters supported the full repeal of the reasonable and necessary definition in the MCIT/R&N final rule. Similar to the past two public comment periods, many commenters requested that CMS bifurcate MCIT and R&N into separate rules because they are independent and distinct provisions with different implications for Medicare policy. Commenters noted that the codification of a R&N definition is significant because it affects all Medicare items and services and represents a change from current practice. Commenters reiterated their position that the definition needs more public input and CMS should ensure it receives feedback from all interested parties, which is a broader group than the audience with expertise and interest in the MCIT pathway.

Response: We agree that further stakeholder engagement on the topic is warranted; and therefore, we will finalize the repeal of the R&N definition. Similar to what we described previously for MCIT, we are exploring potential opportunities for obtaining additional stakeholder feedback via listening sessions, town hall meetings, or other means. We acknowledge the requests made by a number of commenters to bifurcate MCIT and R&N into separate rules for the purposes of future rulemaking. We will consider these comments as we address these issues in the future.

Comment: The commenters cited concerns that if codified, the definition of reasonable and necessary in the MCIT/R&N final rule would remove flexibility and may impact CMS's ability to ensure equitable health care. Some stated that the definition as finalized would be problematic for lab tests.

Response: Further stakeholder engagement on the topic is warranted. We will consider these comments as we address these issues in the future.

Comment: Several commenters questioned whether a codified definition is necessary as they believe that the current definition in Chapter 13 of the CMS Program Integrity Manual is a sufficient framework that preserves the necessary flexibility to provide appropriate access. A significant number of commenters indicated their support for maintaining the definition in subregulatory guidance. Commenters noted that CMS has not provided a clear rationale for why codification of the definition in regulation is necessary or beneficial and that CMS should more clearly articulate the benefits and drawbacks associated with codification as compared to the status quo.

Response: We will finalize our proposed rule to repeal the R&N definition. As noted previously, we believe further stakeholder engagement on the definition is warranted. We will consider these comments as we address these issues in the future.

Comment: The majority of commenters supported the repeal of the commercial insurer criterion in the R&N definition. Commenters reiterated that commercial coverage policies already can (and have been) reviewed by CMS as part of the NCD process. Commenters further note that formalizing their inclusion could lead to an item or service that had been covered previously becoming non-covered depending on how a specific commercial payor may have determined coverage. Commenters reiterated their concerns regarding implementation of commercial insurer policy provisions, the potential of unnecessarily restricting coverage by relying on commercial insurer policies designed for a different population with different incentives, commercial insurer policies' lack of transparency, and potential for fraud and abuse. A few commenters cited a concern that some commercial plans consider costs in their decisions which could potentially violate the Medicare statutory prohibition regarding consideration of cost in coverage determinations. Lastly, a commenter questioned why CMS would want to cede this authority to other entities.

Response: We appreciate these comments. We agree with commenters that CMS can (and has) reviewed commercial policies in recent years as part of a national coverage analysis. After further consideration of public comments, we no longer agree with our position in the January 2021 MCIT/R&N final rule that it is necessary to include regulatory language to give us clear authority to review commercial insurers' policies. Because we are finalizing the full repeal of the R&N definition, we will not be issuing subregulatory guidance on consideration of commercial insurer coverage polices when there is insufficient evidence to make a national or local coverage determination. Further, we would like to clarify that while CMS has a long-standing position to not consider costs when making coverage determinations, it is not because of a statutory prohibition.

Comment: Though commenters were largely opposed to the inclusion of the commercial insurance aspects of the

R&N definition, some commenters offered alternative approaches for CMS to consider in applying commercial payer policies. Specifically, some commenters recommended commercial policies only be utilized as evidence to support expansion of coverage on a proposed policy or asking for a reconsideration of an existing one.

Response: We appreciate these comments. As noted previously, we can use the private market as a source of evidence for coverage.

Comment: A few commenters disagreed with CMS' proposal to fully repeal the definition of R&N. These commenters expressed their support for a R&N definition in line with the definition in Chapter 13 of the PIM. One of these commenters specifically encouraged CMS to codify the R&N definition stating that it is a much needed step and something that CMS has sought to do for decades.

Response: We appreciate these comments. However, after considering the totality of the comments, we believe that the overarching issues raised by commenters, in particular issues regarding the need for more clarity and broader stakeholder input, warrant further consideration and engagement before moving forward with a codified definition of R&N. As other commenters noted, a codified definition of R&N is a considerable change from current practice and will affect all Medicare services. We believe it is important to provide for additional stakeholder feedback on this topic that includes a wider group of stakeholders than those who may have offered input during rulemaking for the MCIT/R&N final rule. We look forward to engaging with stakeholders in the future as we determine appropriate next steps that are in the best interest of the Medicare program and all stakeholders.

Comment: Some commenters expressed opposition to only repealing the commercial aspects of the R&N definition. A commenter stated that trying to leave part of the rule in place now does not provide adequate opportunity for comment, as stakeholders do not truly know what is being proposed for comment.

Response: We appreciate these comments. We acknowledge that commenters representing a wide range of stakeholder groups want more clarity from CMS and more opportunities to provide input before we move forward with codifying a definition of R&N. As noted previously, we look forward to engaging with stakeholders on this topic.

Comment: Commenters provided many suggestions as to what criteria CMS should consider as part of the R&N definition in response to our solicitation for that information in the September 2021 proposed rule. Specifically, a commenter noted that a definition of R&N should take into consideration the perspective of providers and enhance the ability of providers to use their medical judgment. Another commenter stated that CMS should adhere to a definition that is patient-focused. Some commenters noted that Medicare should consider the definition of appropriateness for Medicare beneficiaries since not all beneficiaries are aged 65 and older, and all beneficiaries should be considered. A commenter recommended that the definition should be expanded to include maintenance or prevention of deterioration of function as well. Some commenters expressed concern with the inclusion of 'safe and effective' in the definition and contend that Medicare coverage should not be dependent on meeting standards established by FDA for a different purpose. Some commenters recommended that CMS eliminate the inclusion of ''at least as beneficial as an existing and available medically appropriate alternative'' in the definition. A commenter stated that it was problematic as it as it appears to impose a comparative effectiveness requirement for coverage.

Response: We appreciate the informative and helpful recommendations provided by commenters. We will consider these comments for potential future policy development. As noted previously, we intend to provide additional opportunities for stakeholders to provide feedback on this topic and look forward to further engagement with stakeholders.

Final Decision: After review of the public comments received, we are finalizing the repeal of the January 2021 MCIT/R&N final rule as proposed in the September 2021 proposed rule without modification.

C. Effect of Proposed Repeal

In the September 2021 proposed rule, we stated that if the MCIT/R&N final rule is repealed as proposed, the revisions to part 405 of title 42 of the Code of Federal Regulations would not occur and the text would remain unchanged. Specifically, a definition of ''reasonable and necessary'' would not be included among the terms defined at 42 CFR 405.201(b) and the guidance that the rule would have required (subregulatory guidance on the topic of utilization of commercial insurer polies) would not be introduced. Additionally, subpart F, which wholly consisted of Medicare Coverage of Innovative Technology, would not be added, and subpart F would remain reserved for other purposes.

After review of the public comments received, we are finalizing the repeal of the January 2021 MCIT/R&N final rule as proposed in the September 2021 proposed rule without modification.

III. Regulatory Impact Analysis

A. Statement of Need

The purpose of this final rule is to repeal the MCIT/R&N final rule. As stated in the preceding sections, we are repealing MCIT because this coverage policy is not in the best interest of Medicare beneficiaries. We are repealing the definition of R&N because further stakeholder engagement on the topic is warranted based on stakeholder feedback. CMS developed MCIT in part due to concerns that delays and uncertainty in Medicare coverage slowed innovation and impaired beneficiary access to important new technologies, specifically those designated as breakthrough devices by FDA. We believe that the finalized MCIT/R&N rule is not in the best interest of Medicare beneficiaries because the rule may provide coverage without adequate evidence that the Breakthrough Device would be a reasonable and necessary treatment for the Medicare patients that have the particular disease or condition that the device is intended to treat or diagnose.

The definition of ''reasonable and necessary'' in the MCIT/R&N final rule mirrored the longstanding CMS Program Integrity Manual's definition of ''reasonable and necessary'' with a modification to the appropriateness factor to specify when and how (upon publication of guidance) we would utilize commercial insurer coverage policies. This final rule to not codify the definition of R&N maintains the status quo with respect to the use of the CMS Program Integrity Manual's definition and is responsive to the numerous stakeholders who requested that, if CMS were to develop a definition of reasonable and necessary, that the stakeholder engagement process would require more than public comment via rulemaking.

Through this final rule we repeal the MCIT/R&N final rule and, as stated previously, intend to work with stakeholders to develop a coverage policy and definition for R&N that addresses the concerns they raised. CMS plans on hosting at least two stakeholder meetings with several audiences, including, but not limited to,

manufacturers, clinicians, patients, and disability groups.

This final rule repeals the MCIT pathway and codification of the definition of ''reasonable and necessary.'' Because the January 2021 final rule effective date was delayed until December 15, 2021, the MCIT coverage pathway and definition of ''reasonable and necessary'' have not been implemented, and no payments for items and services have been made in relation to these provisions because they have not taken effect. In the January 2021 final rule, we included a robust regulatory impact analysis of these provisions. Because the final rule did not go into effect, and this final rule repeals the provisions, there has not been an impact from these provisions nor will there be an impact, relative to current coverage practice, upon repeal; however, effects would be non-negligible relative to the future trajectory without this repeal.

In the September 2021 proposed rule, we examined the impact of the repealing the MCIT/R&N final rule as required by Executive Order 12866 on Regulatory Planning and Review (September 30, 1993), Executive Order 13563 on Improving Regulation and Regulatory Review (January 18, 2011), the Regulatory Flexibility Act (RFA) (September 19, 1980, Pub. L. 96–354), section 1102(b) of the Social Security Act, section 202 of the Unfunded Mandates Reform Act of 1995 (March 22, 1995; Pub. L. 104–4), Executive Order 13132 on Federalism (August 4, 1999), the Congressional Review Act (5 U.S.C. 804(2)).

Executive Orders 12866 and 13563 direct agencies to assess all costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, distributive impacts, and equity). Section 3(f) of Executive Order 12866 defines a ''significant regulatory action'' as an action that is likely to result in a rule: (1) Having an annual effect on the economy of $100 million or more in any 1 year, or adversely and materially affecting a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local or tribal governments or communities (also referred to as ''economically significant''); (2) creating a serious inconsistency or otherwise interfering with an action taken or planned by another agency; (3) materially altering the budgetary impacts of entitlement grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) raising novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive order.

A regulatory impact analysis (RIA) must be prepared for major rules with economically significant effects ($100 million or more in any 1 year). The MCIT/R&N 2021 final rule reached the economic threshold and thus was considered a major rule. Because this final rule completely repeals the provisions, this rule also reaches the economic threshold and its finalization is a major rule. Accordingly, we have prepared a Regulatory Impact Analysis that to the best of our ability presents the costs and benefits of the rulemaking. Therefore, based on our estimates, OMB's Office of Information and Regulatory Affairs has determined that this rulemaking is ''economically significant'' as measured by the $100 million threshold, and hence also a major rule under Subtitle E of the Small Business Regulatory Enforcement Fairness Act of 1996 (also known as the Congressional Review Act).

B. Detailed Economic Analysis

1. MCIT Pathway

CMS considered alternatives to repealing the MCIT pathway and the definition of reasonable and necessary, such as maintaining the provisions of the MCIT/R&N final rule and further delaying the effective date. For the reasons described in detail in section II. of this rule such as patient safety and need for further public engagement, we chose to repeal the provisions. We note that further delay of the MCIT/R&N final rule would not alter the patient safety concerns inherent in the MCIT pathway.

As described in the MCIT/R&N final rule, the impacts of the MCIT pathway and defining ''reasonable and necessary'' were hard to quantify without knowing the specific Breakthrough Devices that would seek MCIT and other items and services that would be included in future NCDs and LCDs and the criteria that CMS would use for determining which commercial insurers will be considered.

In the MCIT/R&N final rule specifically for MCIT, we considered regulatory alternatives to combine Medicare coverage with clinical evidence development under section 1862(a)(1)(E) of the Act, to take no regulatory action, or to adjust the duration of the MCIT pathway.

The impact of implementing the MCIT pathway was difficult to determine without knowing the specific Breakthrough Devices that would be covered. In addition, many of these devices would be eligible for coverage in the absence of the rule, such as through a local or national coverage determination, so the impact for certain items may be the acceleration of coverage by just a few months. Furthermore, some of these devices would be covered immediately if the MACs decide to pay for them, which would result in no impact on Medicare spending for devices approved under this pathway. However, it is possible that some of these Breakthrough Devices would not otherwise be eligible for coverage in the absence of the rule. Because it was not known how these new technologies would otherwise come to market and be reimbursed, it was not possible to develop a point estimate of the impact. In general, we believed the MCIT coverage pathway would have ranged in impact from having no impact on Medicare spending to a temporary cost for innovations that are adopted under an accelerated basis.

The decision to enter the MCIT pathway would have been voluntary for the manufacturer. Because manufacturers typically join the Medicare coverage pathway that is most financially beneficial to them, this could result in selection against the existing program coverage pathways (to what degree is unknown at this point). In addition, the past trend of new technology costing more than existing technology could lead to a higher cost for Medicare if this trend continued for technologies enrolling in the MCIT pathway. Nevertheless, new technology may also mitigate ongoing chronic health issues or improve efficiency of services thereby reducing some costs for Medicare.

To demonstrate the potential impact on Medicare spending, for MCIT the CMS Office of the Actuary (OACT) developed three hypothetical scenarios that illustrate the impact of implementing the MCIT pathway. Scenarios two and three assumed that the device would not have been eligible for coverage in the absence of MCIT (see Table 1). The illustration used the new devices that applied for a NTAP in fiscal year (FY) 2020 as a proxy for the new devices that would utilize the MCIT pathway. The submitted cost and anticipated utilization for these devices was published in the **Federal Register**.[8] In addition, we assumed that two manufacturers would elect to utilize the

[8] FY 2020 Hospital Inpatient Prospective Payment System (IPPS) Proposed Rule (84 FR 19640 and 19641) (May 3, 2019) *available at https://www.govinfo.gov/content/pkg/FR-2019-05-03/pdf/2019-08330.pdf* (accessed October 17, 2019).

MCIT pathway in the first year, three manufacturers in the second year, four manufacturers in the third year, and five manufacturers in the fourth year each year for all three scenarios. This assumption is based on the number of medical devices that received FY 2020 NTAP and were non-covered in at least one MAC jurisdiction by LCDs and related articles and our impression from the FDA that the number of devices granted breakthrough status is increasing. For the first scenario, the no-cost scenario, we assumed that all the devices would be eligible for coverage in the absence of MCIT. If the devices received coverage and payment nationally and at the same time then there would be no additional cost under this pathway. For the second scenario, the low-cost scenario, we assumed that the new technologies would have the average costs ($2,044) and utilization (2,322 patients) of similar technologies included in the FY 2020 NTAP application cycle. Therefore, to estimate the first year of MCIT, we multiplied the add-on payment for a new device by the anticipated utilization for a new device by the number of anticipated devices in the pathway ($2,044 × 2,322 × 2 = $ 9.5 million). For the third scenario, the high-cost scenario, we assumed the new technologies would receive the maximum add-on payment from the FY 2020 NTAP application cycle ($22,425) and the highest utilization of a device (6,500 patients). Therefore, to estimate for the first year of MCIT, we estimated similarly ($22,425 × 6,500 patients × 2 = $ 291.5 million). For subsequent years, we increased the number of anticipated devices in the pathway by three, four, and five in the last two scenarios until 2024.[9] In addition to not taking into account inflation, the illustration does not reflect any offsets for the costs of these technologies that would be utilized through existing authorities nor the cost of other treatments (except as noted). It is not possible to explicitly quantify these offsetting costs but they could substantially reduce or eliminate the net program cost. However, by assuming that only two to five manufacturers would elect MCIT coverage, we implicitly assumed that, while more manufacturers could potentially elect coverage under MCIT, the majority of devices would have been covered under a different coverage pathway. Therefore, a substantial portion of the offsetting costs are implicitly reflected.

Based on this analysis, there was a range of potential impacts of MCIT as shown in Table 1. The difference between the three estimates demonstrates how sensitive the impact is to the cost and utilization of these unknown devices.

Because MCIT has not yet been implemented, we lack evidence with which to update the earlier estimates, so Table 1, only differs from the analogous table accompanying the MCIT/R&N final rule in terms of the sign (that is, the direction) on the estimates and a shifting of the time horizon by one year so as to avoid stating this MCIT would have effects in the nearly-ended FY 2021.

TABLE 1—ILLUSTRATED IMPACT ON THE MEDICARE PROGRAM BY MCIT COVERAGE PATHWAY

	Costs (in millions)			
	FY 2022	FY 2023	FY 2024	FY 2025
No-cost Scenario	$0	$0	$0	$0
Low-cost Scenario	−9.5	−23.7	−42.7	−66.4
High-cost Scenario	−291.5	−728.8	−1,311.9	−2,040.7

The RFA requires agencies to analyze options for regulatory relief of small entities. For purposes of the RFA, small entities include small businesses, nonprofit organizations, and small governmental jurisdictions. Some hospitals and other providers and suppliers are small entities, either by nonprofit status or by having revenues of less than $7.5 million to $38.5 million in any 1 year. Individuals and States are not included in the definition of a small entity. For the MCIT/R&N final rule, we reviewed the Small Business Administration's Table of Small Business Size Standards Matched to North American Industry Classification System (NAICS) Codes to determine the NAICS U.S. industry titles and size standards in millions of dollars and/or number of employees that apply to small businesses that could be impacted by this rule. We determined that small businesses potentially impacted by that rule include surgical and medical instrument manufacturers (NAICS code 339112, dollars not provided/1,000 employees), Offices of Physicians (except Mental Health Specialists) (NAICS code 621111, $12 million/employees not provided), and Freestanding Ambulatory Surgical and Emergency Centers (NAICS code 621493, $16.5 million/employees not provided). Because the impact of this final rule is ultimately no change in current coverage policy, we determined that small businesses identified would not be impacted by this final rule. Given the nature of the breakthrough devices market authorized thus far and the timely notification of the MCIT/R&N final rule's delay of effective date, we do not anticipate that small businesses would have made investment decisions or experienced a loss of anticipated positive reimbursement as a result of the MCIT/R&N final rule. Because MCIT has not gone into effect, and we are repealing the rule, payments have not occurred under MCIT; therefore, the impact of this final rule is neither an increase nor decrease in revenue for providers. We are not preparing a further analysis for the RFA because we have determined, and the Secretary of the Department of Health and Human Services (the Secretary) certifies, that this final rule will not have a significant negative economic impact on a substantial number of small entities because small entities are not being asked to undertake additional effort or take on additional costs outside of the ordinary course of business.

[9] An indirect effect of the final rule would be decreased distortions in the labor markets taxed to support the Medicare Trust Fund. Such distortions are sometimes referred to as marginal excess tax burden (METB), and Circular A–94—OMB's guidance on cost-benefit analysis of Federal programs, available at *https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A94/a094.pdf*—suggests that METB may be valued at roughly 25 percent of the estimated transfer attributed to a policy change; the Circular goes on to direct the inclusion of estimated METB change in supplementary analyses. If secondary costs and cost savings—such as decreased marginal excess tax burden, in the case of this final rule—are included in regulatory impact analyses, then secondary benefits must be as well, in order to avoid inappropriately skewing the net benefits results, and including METB only in supplementary analyses provides some acknowledgement of this potential imbalance.

In addition, section 1102(b) of the Act requires us to prepare a regulatory impact analysis if a rule may have a significant impact on the operations of a substantial number of small rural hospitals. This analysis must conform to the provisions of section 604 of the RFA. For purposes of section 1102(b) of the Act, we define a small rural hospital as a hospital that is located outside of a Metropolitan Statistical Area for Medicare payment regulations and has fewer than 100 beds. We are not preparing an analysis for section 1102(b) of the Act because we have determined, and the Secretary certifies, that this final rule would not have a significant impact on the operations of a substantial number of small rural hospitals because small rural hospitals are not being asked to undertake additional effort or take on additional costs outside of the ordinary course of business. Obtaining Breakthrough Devices for patients is at the discretion of providers. We are not requiring the purchase and use of Breakthrough Devices. Providers should continue to work with their patients to choose the best treatment. For small rural hospitals that provide Breakthrough Devices to their patients, this final rule would not change the way they are currently covered through the Medicare program.

2. ''Reasonable and Necessary'' Definition

In order to demonstrate the potential impact on Medicare spending for the definition of ''reasonable and necessary'' in the MCIT/R&N final rule we developed scenarios that illustrated the impact of implementing the two alternatives considered (no change/not codifying a definition and codifying a definition). One of the options was making no change, that is not codifying the definition of ''reasonable and necessary'' in regulations. The number of NCDs and LCDs finalized in a given year can vary and the cost of items and services within the coverage decisions varies. Further, while we reviewed coverage of items and services, we did not take into account unique Medicare rules regarding which type of providers/clinicians may furnish certain services, place of service requirements, or payment rules. Our analysis was based on whether Medicare covered or non-covered an item or service and based on the numbers of NCDs and LCDs finalized in 2020 (see Table 1). In 2020, CMS and the MACs finalized 3 NCDs and 31 LCDs. (This number represents new LCDs in 2020 and made publicly available via the Medicare Coverage Database. If more than one MAC jurisdiction issued an LCD on the same item or service with the same coverage decision, only 1 of the LCDs was included in the count.) Of the NCDs finalized in 2020, all 3 resulted in expanded national Medicare coverage. Because none of those NCDs resulted in non-coverage, we did not evaluate whether commercial insurers would have covered the item or service. Therefore, based on 2020 data for NCDs only, the impact would be $0.

Of the 31 LCDs, 27 provided Medicare positive coverage and 4 resulted in non-coverage. For these non-covered items and services, we established that the possible range of the cumulative cost of covering them could be from $0 to $3.4 billion for a single year (based on price and approximate Medicare beneficiary utilization). Because our analysis looked for any commercial insurer that covered the item or service, the cost may be less when utilizing commercial insurer polices that represent a majority of covered lives. In addition, even if a commercial insurer covers an item or service, the final rule did not require automatic Medicare coverage. Therefore, not all items and services that are non-covered by Medicare but covered by commercial insurance would be presumed covered under the MCIT/R&N final rule. Rather, commercial insurer coverage would have been a factor that CMS would have taken into account as part of the body of evidence in determining coverage through the NCD and LCDs processes. Because not all commercial insurer positive coverage will necessarily translate to Medicare coverage and because CMS was to define which types of commercial insurers (based on majority of covered lives) would be relevant, we believe that commercial insurer coverage impact is likely much smaller, closer to 15 to 25 percent of $3.4 billion, that is, $51 to $880 million.

TABLE 2—ILLUSTRATED IMPACT FOR THE MEDICARE PROGRAM BY DEFINITION OF REASONABLE AND NECESSARY

	Estimated change in Medicare costs for the alternatives considered for the MCIT/R&N final rule	
	No change (not codifying a definition)	Codified definition
Coverage Determinations (NCDs and LCDs)	$0	$51–880 million

Section 202 of the Unfunded Mandates Reform Act of 1995 also requires that agencies assess anticipated costs and benefits before issuing any rule whose mandates require spending in any 1 year of $100 million in 1995 dollars, updated annually for inflation. In 2021, that threshold was approximately $158 million. This final rule would not impose a mandate that will result in the expenditure by State, local, and Tribal Governments, in the aggregate, or by the private sector, of more than $158 million in any one year.

Executive Order 13132 establishes certain requirements that an agency must meet when it promulgates a final rule that imposes substantial direct requirement costs on State and local governments, preempts State law, or otherwise has federalism implications. Since this final rule does not impose any costs on State or local governments, the requirements of Executive Order 13132 are not applicable.

Comment: A few commenters expressed concerns regarding the financial impact of the MCIT/R&N final rule, including that CMS' impact estimate of $0 to $4 billion over the first several years indicated that CMS could not assess the potential impact given the multiple variables involved. Another commenter asserted that the MCIT/R&N final rule significantly underestimated anticipated spending and would accelerate Medicare Trust Fund insolvency.

Response: We acknowledge that assessing the financial impact of MCIT, with multiple variables and limited access to publicly available data to derive impacts, makes it difficult to estimate precise spending on the policy. For future rulemaking, we anticipate this estimate to become more finely tuned as more public-facing data about Breakthrough Devices becomes available.

C. Alternatives Considered

CMS considered alternatives to repealing the MCIT pathway and the definition of reasonable and necessary, such as maintaining the provisions of the MCIT/R&N final rule and further delaying the effective date. For the reasons described in detail in section II. of this final rule such as patient safety and need for further public engagement, we chose to repeal the provisions. We described the impact of these MCIT alternatives in Table 1. The alternative considered for not codifying the definition of ''reasonable and necessary'' was to codify the definition. We describe the impact of codifying the definition in Table 2.

D. Accounting Statement and Table

We have prepared an accounting statement showing the classification of the expenditures associated with the provisions of this final rule. This table addresses the costs that would have been incurred through implementing the MCIT/R&N final rule, but, due to this final rule repealing that rule, reflects that those costs will not be incurred under the policies.

As required by OMB Circular A–4 (available at *https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf*), we have prepared an accounting statement in Table 3 showing the classification of the impact associated with the provisions of this final rule.

TABLE 3—ACCOUNTING STATEMENT

Category	Primary estimate	Minimum estimate	Maximum estimate	Unit rate			Source citation (RIA, preamble, etc.)
				Year dollar	Discount rate (%)	Period covered	
Transfers:							
Federal Annualized monetized transfers: ''on budget'' ($millions/year)MCIT.	.....	(34.0)	(1,044.1)	2022	7	2022–2025	*RIA:* This reflects the repeal of MCIT. We estimated a zero-cost scenario for each of the fiscal years 2022–2025.
MCIT	.....	(34.9)	(1,071.7)	2022	3	2022–2025	
Definition of ''Reasonable and Necessary''.	.....	(51.0)	(880.0)	2022	7	2022–2025	*RIA:* This reflects the repeal of the reasonable and necessary definition.
		(51.0)	(880.0)	2022	3	2022–2025	
From whom to whom?.	From: Federal Government		To: Medicare Providers				

Note: Items in parentheses indicate negative numbers.

This final rule is subject to the Congressional Review Act provisions of the Small Business Regulatory Enforcement Fairness Act of 1996 (5 U.S.C. 801 *et seq.*) and has been transmitted to the Congress and the Comptroller General for review.

Chiquita Brooks-LaSure, Administrator of the Centers for Medicare & Medicaid Services, approved this document on November 9, 2021.

List of Subjects in 42 CFR Part 405

Administrative practice and procedure, Diseases, Health facilities, Health professions, Medical devices, Medicare, Reporting and recordkeeping requirements, Rural areas, X-rays.

For the reasons set forth in the preamble, the Centers for Medicare & Medicaid Services amends 42 CFR part 405 as set forth below:

PART 405—FEDERAL HEALTH INSURANCE FOR THE AGED AND DISABLED

■ 1. The authority for part 405 continues to read as follows:

Authority: 42 U.S.C. 263a, 405(a), 1302, 1320b–12, 1395x, 1395y(a), 1395ff, 1395hh, 1395kk, 1395rr, and 1395ww(k).

§ 405.201 [Amended]

■ 2. Section 405.201 is amended in paragraph (b) by removing the definition for ''Reasonable and necessary''.

Subpart F—[Removed and Reserved]

■ 3. Remove and reserve subpart F, consisting of §§ 405.601 through 405.607.

Dated: November 9, 2021.

Xavier Becerra,

Secretary, Department of Health and Human Services.

[FR Doc. 2021–24916 Filed 11–12–21; 8:45 am]

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 210325–0071; RTID 0648–XB583]

Fisheries of the Northeastern United States; Atlantic Herring Fishery; 2021 Management Area 1A Closure Possession Limit

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Temporary rule; possession limit reduction.

SUMMARY: NMFS is implementing a 2,000-lb (907.2-kg) possession limit for Atlantic herring for Management Area 1A. This is required because NMFS projects that herring catch from Area 1A will reach 92 percent of the Area's sub-annual catch limit before the end of the fishing year. This action is intended to

prevent overharvest of herring in Area 1A, which would result in additional catch limit reductions in a subsequent year.

DATES: Effective 00:01 hr local time, November 11, 2021, through December 31, 2021.

FOR FURTHER INFORMATION CONTACT: Maria Fenton, Fishery Management Specialist, (978) 281–9196.

SUPPLEMENTARY INFORMATION: The Regional Administrator of the Greater Atlantic Regional Office monitors Atlantic herring fishery catch in each Management Area based on vessel and dealer reports, state data, and other available information. Regulations at 50 CFR 648.201(a)(1)(i)(A) require that we implement a 2,000-lb (907.2-kg) possession limit for herring for Area 1A beginning on the date that catch is projected to reach 92 percent of the sub-annual catch limit (ACL) for that area.

Based on vessel reports, dealer reports, and other available information the Regional Administrator projects that the herring fleet will have caught 92 percent of the Area 1A sub-ACL by November 8, 2021. Therefore, effective 00:01 hr local time November 11, 2021, through December 31, 2021, a person may not attempt or do any of the following: Fish for; possess; transfer; purchase; receive; land; or sell more than 2,000 lb of herring per trip or more than once per calendar day in or from Area 1A.

Vessels that enter port before 00:01 hr local time on November 11, 2021, may land and sell more than 2,000 lb (907.2 kg) of herring from Area 1A from that trip, provided that catch is landed in accordance with state management measures. Vessels may transit or land in Area 1A with more than 2,000 lb (907.2 kg) of herring on board, provided that: The herring were caught in an area not subject to a 2,000-lb (907.2-kg) limit; all fishing gear is stowed and not available for immediate use; and the vessel is issued a permit appropriate to the amount of herring on board and the area where the herring was harvested.

Also effective 00:01 hr local time, November 11, 2021, through 24:00 hr local time, December 31, 2021, federally permitted dealers may not attempt or do any of the following: Purchase; receive; possess; have custody or control of; sell; barter; trade; or transfer more than 2,000 lb (907.2 kg) of herring per trip or calendar day from Area 1A, unless it is from a vessel that enters port before 00:01 hr local time on November 11, 2021, and catch is landed in accordance with state management measures.

Classification

This action is required by 50 CFR part 648 and is exempt from review under Executive Order 12866.

NMFS finds good cause pursuant to 5 U.S.C. 553(b)(3)(B) to waive prior notice and the opportunity for public comment because it is unnecessary, contrary to the public interest, and impracticable. Ample prior notice and opportunity for public comment has been provided for the required implementation of this action. The requirement to implement this possession limit was developed by the New England Fishery Management Council using public meetings that invited public comment on the measures when they were developed and considered along with alternatives. Further, the regulations requiring NMFS to implement this possession limit also were subject to public notice and opportunity to comment, when they were first adopted in 2014. Herring fishing industry participants monitor catch closely and anticipate potential directed fishery closures as catch totals approach Area sub-ACLs. The regulation provides NMFS with no discretion and is designed for implementation as quickly as possible to prevent catch from exceeding limits designed to prevent overfishing while allowing the fishery to achieve optimum yield.

The 2021 herring fishing year began on January 1, 2021, and Area 1A opened to fishing on June 13, 2021. Data indicating that the herring fleet will have landed at least 92 percent of the 2021 sub-ACL allocated to Area 1A only recently became available. High-volume catch and landings in this fishery can increase total catch relative to the sub-ACL quickly, especially in this fishing year where annual catch limits are unusually low. If implementation of this closure is delayed to solicit prior public comment, the 2021 sub-ACL for Area 1A will likely be exceeded; thereby undermining the conservation objectives of the Herring Fishery Management Plan (FMP). If sub-ACLs are exceeded, the excess must be deducted from a future sub-ACL and would reduce future fishing opportunities. The public expects these actions to occur in a timely way consistent with the FMP's objectives. For the reasons stated above, NMFS also finds good cause to waive the 30-day delayed effectiveness in accordance with 5 U.S.C 553(d)(3).

Authority: 16 U.S.C. 1801 *et seq.*

Dated: November 8, 2021.

Ngagne Jafnar Gueye,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2021–24828 Filed 11–9–21; 4:15 pm]

BILLING CODE 3510–22–P

Proposed Rules

Federal Register
Vol. 86, No. 217
Monday, November 15, 2021

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2021–0957; Project Identifier AD–2021–00469–T]

RIN 2120–AA64

Airworthiness Directives; The Boeing Company Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to adopt a new airworthiness directive (AD) for certain The Boeing Company Model 747–8F and 747–8 series airplanes. This proposed AD was prompted by a report of unusual flight instrument and engine indication and crew alerting system (EICAS) behavior. This proposed AD would require inspecting the left, center, and right electronic flight instrument system (EFIS)/EICAS interface unit (EIU) for certain serial numbers and replacement if necessary. The FAA is proposing this AD to address the unsafe condition on these products.

DATES: The FAA must receive comments on this proposed AD by December 30, 2021.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *https://www.regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this NPRM, contact Boeing Commercial Airplanes, Attention: Contractual & Data Services (C&DS), 2600 Westminster Blvd., MC 110–SK57, Seal Beach, CA 90740–5600; telephone 562–797–1717; internet *https://www.myboeingfleet.com.* You may view this referenced service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195. It is also available on the internet at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2021–0957.

Examining the AD Docket

You may examine the AD docket at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2021–0957; or in person at Docket Operations between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this NPRM, any comments received, and other information. The street address for Docket Operations is listed above.

FOR FURTHER INFORMATION CONTACT: Jeffrey Palmer, Aerospace Engineer, Systems and Equipment Section, FAA, Los Angeles ACO Branch, 3960 Paramount Boulevard, Lakewood, CA 90712–4137; phone: 562–627–5351; fax: 562–627–5210; email: *jeffrey.w.palmer@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

The FAA invites you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under **ADDRESSES**. Include ''Docket No. FAA–2021–0957; Project Identifier AD–2021–00469–T'' at the beginning of your comments. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include supporting data. The FAA will consider all comments received by the closing date and may amend this proposal because of those comments.

Except for Confidential Business Information (CBI) as described in the following paragraph, and other information as described in 14 CFR 11.35, the FAA will post all comments received, without change, to *https://www.regulations.gov,* including any personal information you provide. The agency will also post a report summarizing each substantive verbal contact received about this NPRM.

Confidential Business Information

CBI is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (FOIA) (5 U.S.C. 552), CBI is exempt from public disclosure. If your comments responsive to this NPRM contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this NPRM, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission containing CBI as ''PROPIN.'' The FAA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this NPRM. Submissions containing CBI should be sent to Jeffrey Palmer, Aerospace Engineer, Systems and Equipment Section, FAA, Los Angeles ACO Branch, 3960 Paramount Boulevard, Lakewood, CA 90712–4137; phone: 562–627–5351; fax: 562–627–5210; email: *jeffrey.w.palmer@faa.gov.* Any commentary that the FAA receives which is not specifically designated as CBI will be placed in the public docket for this rulemaking.

Background

The FAA has received a report indicating that an operator of a 747–8 airplane reported an in-flight event in which the captain's primary flight display (PFD) and navigation display (ND) flickered after an involuntary autopilot disconnect, followed by the blanking of the main EICAS display unit. EICAS information was displayed on the lower EICAS display unit for the remainder of the flight. Multiple EICAS messages and unusual checklists appeared intermittently. The crew observed a master caution light and beeper as these messages appeared and disappeared. The over speed/stall red dots were displayed all along the captain's speed tape; however, there was no over speed aural alert or stick shaker. The flightcrew declared PAN–PAN (urgent situation) due to unusual flight instrument and EICAS behavior

and the airplane landed safely. The root cause of this incident was found to be a hardware problem in the EIU, specifically the input/output (I/O) chip on the affected Aeronautical Radio, Incorporated (ARINC), I/O card. Hand-brushed application of the conformal coating led to an excess of the conformal coating migrating underneath the I/O chip. This resulted in an interconnect problem between the I/O chip and the ARINC I/O card. This condition, if not addressed, could result in reduced ability of the flightcrew to maintain continued safe flight and landing of the aircraft.

FAA's Determination

The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop on other products of the same type design.

Related Service Information Under 1 CFR Part 51

The FAA reviewed Boeing Alert Requirements Bulletin 747–31A2565 RB, Revision 1, dated September 14, 2021. This service information specifies procedures for doing an inspection or a review of the maintenance and delivery records of the left, center, and right EIUs for any affected serial number, and replacing each affected EIU.

This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in **ADDRESSES**.

Proposed AD Requirements in This NPRM

This proposed AD would require accomplishing the actions specified in the service information already described, except for any differences identified as exceptions in the regulatory text of this proposed AD. For information on the procedures and compliance times, see this service information at *https://www.regulations.gov* by searching for and locating Docket No. FAA–2021–0957.

Costs of Compliance

The FAA estimates that this AD, if adopted as proposed, would affect 8 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Inspection	1 work-hour × $85 per hour = $85	$0	$85	$680

The FAA estimates the following costs to do any necessary replacements that would be required based on the results of the proposed inspection. The agency has no way of determining the number of aircraft that might need these replacements:

ON-CONDITION COSTS

Action	Labor cost	Parts cost	Cost per product
Replacement	Up to 3 work-hours × $85 per hour = Up to $255	Up to $9,600	Up to $9,855.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs, describes in more detail the scope of the Agency's authority.

The FAA is issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: General requirements. Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

The FAA determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have 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.

For the reasons discussed above, I certify this proposed regulation:

(1) Is not a ''significant regulatory action'' under Executive Order 12866,

(2) Would not affect intrastate aviation in Alaska, and

(3) Would not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by adding the following new airworthiness directive:

The Boeing Company: Docket No. FAA–2021–0957; Project Identifier AD–2021–00469–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by December 30, 2021.

(b) Affected ADs

None.

(c) Applicability

This AD applies to The Boeing Company Model 747–8F and 747–8 series airplanes, certificated in any category, as identified in Boeing Alert Requirements Bulletin 747–31A2565 RB, Revision 1, dated September 14, 2021.

(d) Subject

Air Transport Association (ATA) of America Code 31, Instruments.

(e) Unsafe Condition

This AD was prompted by a report of unusual flight instrument and engine indication and crew alerting system (EICAS) behavior. The FAA is issuing this AD to address the possible display of incorrect information in the integrated display system (IDS). This condition, if not addressed, could result in reduced ability of the flightcrew to maintain continued safe flight and landing of the aircraft.

(f) Compliance

Comply with this AD within the compliance times specified, unless already done.

(g) Required Actions

Except as specified by paragraph (h) of this AD: At the applicable times specified in the ''Compliance'' paragraph of Boeing Alert Requirements Bulletin 747–31A2565 RB, Revision 1, dated September 14, 2021, do all applicable actions identified in, and in accordance with, the Accomplishment Instructions of Boeing Alert Requirements Bulletin 747–31A2565 RB, Revision 1, dated September 14, 2021.

Note 1 to paragraph (g): Guidance for accomplishing the actions required by this AD can be found in Boeing Alert Service Bulletin 747–31A2565, Revision 1, dated September 14, 2021, which is referred to in Boeing Alert Requirements Bulletin 747–31A2565 RB, Revision 1, dated September 14, 2021.

(h) Exception to Service Information Specifications

Where Boeing Alert Requirements Bulletin 747–31A2565 RB, Revision 1, dated September 14, 2021, uses the phrase ''the Original Issue date of Requirements Bulletin 747–31A2565 RB,'' this AD requires using ''the effective date of this AD.''

(i) Credit for Previous Actions

This paragraph provides credit for the actions specified in paragraph (g) of this AD, if those actions were performed before the effective date of this AD using Boeing Alert Requirements Bulletin 747–31A2565 RB, dated April 27, 2021.

(j) Alternative Methods of Compliance (AMOCs)

(1) The Manager, Seattle ACO Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or responsible Flight Standards Office, as appropriate. If sending information directly to the manager of the certification office, send it to the attention of the person identified in Related Information. Information may be emailed to: *9-ANM-Seattle-ACO-AMOC-Requests@faa.gov.*

(2) Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the responsible Flight Standards Office.

(3) An AMOC that provides an acceptable level of safety may be used for any repair, modification, or alteration required by this AD if it is approved by The Boeing Company Organization Designation Authorization (ODA) that has been authorized by the Manager, Seattle ACO Branch, FAA, to make those findings. To be approved, the repair method, modification deviation, or alteration deviation must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

(k) Related Information

(1) For more information about this AD, contact Jeffrey Palmer, Aerospace Engineer, Systems and Equipment Section, FAA, Los Angeles ACO Branch, 3960 Paramount Boulevard, Lakewood, CA 90712–4137; phone: 562–627–5351; fax: 562–627–5210; email: *jeffrey.w.palmer@faa.gov.*

(2) For information about AMOCs, contact Frank Carreras, Aerospace Engineer, Systems and Equipment Section, FAA, Seattle ACO Branch, 2200 South 216th St., Des Moines, WA 98198; phone and fax: 206–231–3539; email: *frank.carreras@faa.gov.*

(3) For service information identified in this AD, contact Boeing Commercial Airplanes, Attention: Contractual & Data Services (C&DS), 2600 Westminster Blvd., MC 110–SK57, Seal Beach, CA 90740–5600; telephone 562–797–1717; internet *https://www.myboeingfleet.com.* You may view this referenced service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195.

Issued on October 28, 2021.

Lance T. Gant,

Director, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2021–24835 Filed 11–12–21; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2021–0971; Airspace Docket No. 21–AGL–8]

RIN 2120–AA66

Proposed Amendment of VOR Federal Airway V–44 and Revocation of VOR Federal Airway V–446 in the Vicinity of Samsville, IL

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This action proposes to amend VHF Omnidirectional Range (VOR) Federal airway V–44 and revoke VOR Federal airway V–446. The FAA is proposing this action due to the planned decommissioning of the VOR portion of the Samsville, IL, VOR/Distance Measuring Equipment (VOR/DME) navigational aid (NAVAID). The Samsville VOR is being decommissioned in support of the FAA's VOR Minimum Operational Network (MON) program.

DATES: Comments must be received on or before December 30, 2021.

ADDRESSES: Send comments on this proposal to the U.S. Department of Transportation, Docket Operations, 1200 New Jersey Avenue SE, West Building Ground Floor, Room W12–140, Washington, DC 20590; telephone: 1(800) 647–5527, or (202) 366–9826. You must identify FAA Docket No. FAA–2021–0971; Airspace Docket No. 21–AGL–8 at the beginning of your comments. You may also submit comments through the internet at *https://www.regulations.gov.*

FAA Order JO 7400.11F, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *https://www.faa.gov/air_traffic/publications/.* For further information, you can contact the Rules and Regulations Group, Federal Aviation Administration, 800 Independence Avenue SW, Washington, DC 20591; telephone: (202) 267–8783. FAA Order JO 7400.11F is also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of FAA Order JO 7400.11F at NARA, email: *fr.inspection@nara.gov* or go to *https://www.archives.gov/federal-register/cfr/ibr-locations.html.*

FOR FURTHER INFORMATION CONTACT: Colby Abbott, Rules and Regulations Group, Office of Policy, Federal Aviation Administration, 800 Independence Avenue SW, Washington, DC 20591; telephone: (202) 267–8783.

SUPPLEMENTARY INFORMATION:

Authority for This Rulemaking

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use

of the airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it would modify the National Airspace System (NAS) as necessary to preserve the safe and efficient flow of air traffic.

Comments Invited

Interested parties are invited to participate in this proposed rulemaking by submitting such written data, views, or arguments as they may desire. Comments that provide the factual basis supporting the views and suggestions presented are particularly helpful in developing reasoned regulatory decisions on the proposal. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal.

Communications should identify both docket numbers (FAA Docket No. FAA–2021–0971; Airspace Docket No. 21–AGL–8) and be submitted in triplicate to the Docket Management Facility (see **ADDRESSES** section for address and phone number). You may also submit comments through the internet at *https://www.regulations.gov.*

Commenters wishing the FAA to acknowledge receipt of their comments on this action must submit with those comments a self-addressed, stamped postcard on which the following statement is made: ''Comments to FAA Docket No. FAA–2021–0971; Airspace Docket No. 21–AGL–8.'' The postcard will be date/time stamped and returned to the commenter.

All communications received on or before the specified comment closing date will be considered before taking action on the proposed rule. The proposal contained in this action may be changed in light of comments received. All comments submitted will be available for examination in the public docket both before and after the comment closing date. A report summarizing each substantive public contact with FAA personnel concerned with this rulemaking will be filed in the docket.

Availability of NPRMs

An electronic copy of this document may be downloaded through the internet at *https://www.regulations.gov.* Recently published rulemaking documents can also be accessed through the FAA's web page at *https://www.faa.gov/air_traffic/publications/airspace_amendments/.*

You may review the public docket containing the proposal, any comments received and any final disposition in person in the Dockets Office (see **ADDRESSES** section for address and phone number) between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays. An informal docket may also be examined during normal business hours at the office of the Operations Support Group, Central Service Center, Federal Aviation Administration, 10101 Hillwood Parkway, Fort Worth, TX 76177.

Availability and Summary of Documents for Incorporation by Reference

This document proposes to amend FAA Order JO 7400.11F, Airspace Designations and Reporting Points, dated August 10, 2021, and effective September 15, 2021. FAA Order JO 7400.11F is publicly available as listed in the **ADDRESSES** section of this document. FAA Order JO 7400.11F lists Class A, B, C, D, and E airspace areas, air traffic service routes, and reporting points.

Background

The FAA is planning to decommission the Samsville, IL, VOR in September 2022. The Samsville VOR was one of the candidate VORs identified for discontinuance by the FAA's VOR MON program and listed in the Final policy statement notice, ''Provision of Navigation Services for the Next Generation Air Transportation System (NextGen) Transition to Performance-Based Navigation (PBN) (Plan for Establishing a VOR Minimum Operational Network),'' published in the **Federal Register** of July 26, 2016 (81 FR 48694), Docket No. FAA–2011–1082.

Although the VOR portion of the Samsville VOR/DME is planned for decommissioning, the co-located DME portion of the NAVAID is being retained to support current and future area navigation (RNAV) flight procedure requirements.

The air traffic service (ATS) routes affected by the Samsville VOR decommissioning are VOR Federal airways V–44 and V–446. With the planned decommissioning of the Samsville VOR, the remaining ground-based NAVAID coverage in the area is insufficient to enable the continuity of the affected ATS routes. As such, the proposed modification to V–44 would result in a larger gap in the existing airway and the proposed revocation of V–446 in its entirety.

To overcome the proposed modification and revocation to the affected VOR Federal airways, instrument flight rules (IFR) traffic could use portions of adjacent VOR Federal airways, including V–4, V–7, V–52, V–72, and V–221, or receive air traffic control (ATC) radar vectors to fly around or through the affected area. Additionally, IFR pilots equipped with RNAV capabilities could also navigate point to point using the existing NAVAIDs and fixes that would remain in place to support continued operations though the affected area. Visual flight rules (VFR) pilots who elect to navigate via the affected ATS routes could also take advantage of the adjacent ATS routes or ATC services listed previously.

The Proposal

The FAA is proposing an amendment to 14 CFR part 71 to amend VOR Federal airway V–44 and remove VOR Federal airway V–446 due to the planned decommissioning of the Samsville, IL, VOR. The proposed VOR Federal airway actions are described below.

V–44: V–44 currently extends between the Columbia, MO, VOR/DME and the Samsville, IL, VOR/DME; and between the Falmouth, KY, VOR/DME and the Albany, NY, VOR/Tactical Air Navigation (VORTAC). The airspace within restricted areas R–4001B, R–5002A, R–5002B, and R–5002E are excluded when active; the airspace within V–139 and V–308 airways are excluded; and the airspace below 2,000 feet mean sea level (MSL) outside the United States is excluded. The FAA proposes to remove the airway segment between the Centralia, IL, VORTAC and the Samsville, IL, VOR/DME. In reviewing the existing airway, the FAA determined R–4001B, R–5002A, R–5002B, and R–5002E do not overlap the controlled airspace within 4 nautical miles of the V–44 centerline; therefore, the FAA is proposing to remove the exclusion regarding the airspace within R–4001B, R–5002A, R–5002B, and R–5002E when active. Additionally, the FAA is proposing to remove the language excluding the airspace within the V–139 and V–308 airways as well. The unaffected portions of the existing airway would remain as charted.

V–446: V–446 currently extends between the Troy, IL, VORTAC and the Samsville, IL, VOR/DME. The FAA proposes to remove the airway in its entirety.

All NAVAID radials listed in the VOR Federal airway description below are unchanged and stated in True degrees.

VOR Federal airways are published in paragraph 6010(a) of FAA Order JO 7400.11F, dated August 10, 2021, and effective September 15, 2021, which is incorporated by reference in 14 CFR 71.1. The ATS routes listed in this document would be published subsequently in FAA Order JO 7400.11.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

Regulatory Notices and Analyses

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore: (1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under Department of Transportation (DOT) Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this proposed rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

This proposal will be subject to an environmental analysis in accordance with FAA Order 1050.1F, ''Environmental Impacts: Policies and Procedures,'' prior to any FAA final regulatory action.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

In consideration of the foregoing, the Federal Aviation Administration proposes to amend 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for part 71 continues to read as follows:

Authority: 49 U.S.C. 106(f), 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of FAA Order JO 7400.11F, Airspace Designations and Reporting Points, dated August 10, 2021, and effective September 15, 2021, is amended as follows:

Paragraph 6010(a) Domestic VOR Federal Airways.

* * * * *

V–44 [Amended]

From Columbia, MO; INT Columbia 131° and Foristell, MO, 262° radials; Foristell; to Centralia, IL. From Falmouth, KY; York, KY; Parkersburg, WV; Morgantown, WV; Martinsburg, WV; INT Martinsburg 094° and Baltimore, MD, 300° radials; Baltimore; INT Baltimore 122° and Sea Isle, NJ, 267° radials; Sea Isle; INT Sea Isle 040° and Deer Park, NY, 209° radials; Deer Park; INT Deer Park 041° and Bridgeport, CT, 133° radials; Bridgeport; INT Bridgeport 324° and Pawling, NY, 160° radials; Pawling; INT Pawling 342° and Albany, NY, 181° radials; to Albany. The airspace below 2,000 feet MSL outside the United States is excluded.

* * * * *

V–446 [Removed]

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Issued in Washington, DC, on November 3, 2021.

Michael R. Beckles,

Acting Manager, Rules and Regulations Group.

[FR Doc. 2021–24696 Filed 11–12–21; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Parts 887 and 984

[Docket No. FR–6114–P–02]

RIN 2577–AD09

Streamlining and Implementation of Economic Growth, Regulatory Relief, and Consumer Protection Act Changes to Family Self-Sufficiency (FSS) Program; Re-Opening Public Comment Period on the Information Collection Requirements

AGENCY: Office of the Assistant Secretary for Public and Indian Housing, HUD, and Office of the Assistant Secretary for Housing—Federal Housing Commissioner, HUD.

ACTION: Proposed rule; re-opening of comment period.

SUMMARY: On September 21, 2020, HUD published a proposed rule on streamlining and implementing the Economic Growth, Regulatory Relief, and Consumer Protection Act (''the Economic Growth Act''), which would make changes to HUD's Family Self-Sufficiency (FSS) Program. After the publication of that proposed rule, HUD determined that changes to the information collection requirements described in it would be necessary. This supplemental notice of proposed rulemaking therefore re-opens the public comment period on the Streamlining and Implementation of Economic Growth, Regulatory Relief, and Consumer Protection Act Changes to Family Self-Sufficiency (FSS) Program proposed rule (''the 2020 proposed rule'') for an additional 30 days solely to seek comments on revisions to the Paperwork Reduction Act information collection requirements from the 2020 proposed rule. HUD is not soliciting comment on any other issues related to the 2020 proposed rule.

DATES: The comment period for the proposed rule published September 21, 2020, at 85 FR 59234, is re-opened. Comment Due Date: *December 15, 2021.*

ADDRESSES: Interested persons are invited to submit comments regarding this proposed rule. Copies of all comments submitted are available for inspection and downloading at *www.regulations.gov.* To receive consideration as public comments, comments must be submitted through one of two methods, specified below. All submissions must refer to the above docket number and title.

1. *Electronic Submission of Comments.* Interested persons may submit comments electronically through the Federal eRulemaking Portal at *www.regulations.gov.* HUD strongly encourages commenters to submit comments electronically. Electronic submission of comments allows the commenter maximum time to prepare and submit a comment, ensures timely receipt by HUD, and enables HUD to make them immediately available to the public. Comments submitted electronically through the *www.regulations.gov* website can be viewed by other commenters and interested members of the public. Commenters should follow the instructions provided on that site to submit comments electronically.

2. *Submission of Comments by Mail.* Comments may be submitted by mail to the Regulations Division, Office of General Counsel, Department of Housing and Urban Development, 451 7th Street SW, Room 10276, Washington, DC 20410 0500.

FOR FURTHER INFORMATION CONTACT: Aaron Santa Anna, Associate General Counsel for Legislation and Regulations, Office of General Counsel, Department of Housing and Urban Development, 451 7th Street SW, Room 10282, Washington, DC 20410; telephone number 202–402–5300 (this is not a toll-free number). Individuals with hearing- or speech-impairments may access this number via TTY by calling the toll-free Federal Relay Service during working hours at 1–800–877–8339.

SUPPLEMENTARY INFORMATION:

I. Background

On September 21, 2020, at 85 FR 59234, HUD published a proposed rule titled ''Streamlining and Implementation of Economic Growth, Regulatory Relief, and Consumer Protection Act Changes to Family Self-Sufficiency (FSS) Program.'' The 2020 proposed rule would revise the FSS Program regulations to implement statutory requirements, and to reduce burden and streamline the program for PHAs, Multifamily owners, and eligible families. The public comment period closed on November 20, 2020, and HUD received 105 public comments in response to the 2020 proposed rule.

HUD has since determined that changes to the information collection requirements described in the 2020 proposed rule would be necessary for implementation of the rule, or would help the program operate more efficiently. Specifically, HUD notes that all entities that currently operate FSS programs would have to update their Action Plans one time after the new rule becomes effective in order to incorporate regulatory changes, and that PHAs would be required to complete a monitoring self-review checklist for program compliance and reporting once every five years. Additionally, while the 2020 proposed rule noted that the information collection requirements would include paperwork for Multifamily owners, it did not explicitly account for Project-Based Rental Assistance (PBRA) FSS Program Reporting in the description of the information collection.

Additionally, HUD is revising recordkeeping and recording burden estimates for other collection information instruments that were discussed in the 2020 proposed rule. First, HUD anticipates that more funding may be appropriated for the FSS program than HUD anticipated when the 2020 proposed rule was published. Specifically, HUD anticipates that funding will be adequate to support 800 grantees. As a result, HUD is increasing from 750 to 800 the estimate of responses to the SF–424 (''Application for Federal Assistance''). HUD is adjusting to 800 the estimate of responses to the Grant Agreement and the Annual Report/Performance Report. Of these 800 grantees, HUD estimates that approximately 100 will be new grantees. As such, HUD revises the estimate for responses for the NOFA narrative and for Form HUD–52651 (''Family Self-Sufficiency (FSS) Program Coordinator Funding'') to 100. Similarly, HUD estimates that 100 new grantees will submit new Action Plans and estimates that the development of new plans will take 10 hours each. Estimating that about half of these 100 new grantees will be PHAs and the other half will be Multifamily owners, and therefore 750 grantees will be PHAs, HUD estimates that there will be 750 annual respondents for Form HUD–50058 (''Family Report'') and Form HUD–52652 (''Sample FSS Escrow Account Credit Worksheet''). As a result of expected additional FSS funding, HUD has also adjusted the expected number of responses for Cooperative Agreements up to 25 from 15, and the number of responses for Form HUD–52650 (''Family Self-Sufficiency (FSS) Program Contract of Participation'') up to 1,500 from 1,000. Additionally, HUD is removing the burden estimate that appeared in the proposed rule for Form HUD–2994–A (''You are Our Client! Grant Applicant Survey'') (optional), because the form is not in use and is revising the estimated number of responses for Form HUD–52755 (''Sample Contract Administrative Partnership Agreement'') down to 5 from 20, because this form is used only in rare occasions as a corrective action. Finally, HUD is revising the burden hour estimate for this collection for the SF–424 and SF–LLL forms to 0, because their burden is included in different collections.

This supplemental notice of proposed rulemaking re-opens the public comment period on the Streamlining and Implementation of Economic Growth, Regulatory Relief, and Consumer Protection Act Changes to Family Self-Sufficiency (FSS) Program proposed rule for an additional 30 days solely to seek comments on revisions to the Paperwork Reduction Act information collection requirements from the 2020 proposed rule. HUD is not soliciting comment on any other issues related to the 2020 proposed rule.

II. Paperwork Reduction Act

In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520), an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection displays a valid control number. The information collection requirements contained in this supplemental notice of proposed rulemaking will be submitted to the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

The 2020 proposed rule noted that it would require changes to the existing approved paperwork to include PBRA, the addition of a Notice of Funding Availability (NOFA) (now called a ''Notice of Funding Opportunity'' or ''NOFO'') narrative, and the Cooperative Agreement.

After further review, HUD has determined that the revised overall reporting and recordkeeping burden are estimated as follows:

Description of information collection	Number of responses	Responses per year	Total annual responses	Hours per response	Total hours
SF–424—Application for Federal Assistance	800	1	800	0	0
SF–LLL—Disclosure of Lobbying Activities	40	1	40	0	0
Form HUD 2880—Applicant, Recipient, Disclosure, Update Form (OMB No. 2510–0011) [1]	800	1	800	0	0
NOFO Narrative	100	1	100	10	1,000
Cooperative Agreements	25	1	25	2	50
Form HUD–52755—Sample Contract Admin. Partnership Agreement	5	1	5	0.17	.85
Form HUD–52651—FSS Application	100	1	100	1.5	150
Action Plan—New Grantees	100	1	100	10	1,000
Action Plan—One time Update for One year Only After the new Regulation is effective	700	1	700	5	3,500
Form HUD–52650—Contract of Participation	1,500	1	1,500	.25	375
Form HUD–52652—Sample Escrow Account Credit Worksheet	750	100	75,000	.85	63,750
Notice of Award and Terms & Conditions (AKA Grant Agreement*)	800	1	700	N/A	N/A
Annual Report (Narrative)/Performance Report	800	1	800	1	800

Description of information collection	Number of responses	Responses per year	Total annual responses	Hours per response	Total hours
Form HUD–50058—Family Report (OMB No. 2577–0083)	750	100	75,000	0	0
Monitoring Review Self-Assessment Checklist	750	.20	150	2	300
PBRA FSS Program Reporting	200	1	200	1	200
Total				33.7	71,126

* HUD–1044, Award/Amendment is completed by HUD staff, signed by the recipient of the grant, and returned to HUD. This form is a certification, and HUD ascribes no burden to its use.

[1] Burden hours for forms showing zero burden hours in this collection are reflected in the OMB approval number cited or do not have a reportable burden.

III. Questions for Public Comment

In accordance with 5 CFR 1320.8(d)(1), HUD is soliciting comments from members of the public and affected agencies concerning the information collection requirements in this supplemental notice of proposed rulemaking regarding:

(1) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) The accuracy of the agency's estimate of the burden of the proposed collection of information;

(3) Whether the proposed collection of information enhances the quality, utility, and clarity of the information to be collected; and

(4) Whether the proposed information collection minimizes the burden of the collection of information on those who are to respond; including through the use of appropriate automated collection techniques or other forms of information technology (*e.g.,* permitting electronic submission of responses).

Aaron Santa Anna,

Associate General Counsel for Legislation and Regulations.

[FR Doc. 2021–24636 Filed 11–12–21; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF LABOR

29 CFR Part 29

[Docket No. ETA–2021–0007]

RIN 1205–AC06

Apprenticeship Programs, Labor Standards for Registration

AGENCY: Employment and Training Administration, Labor.

ACTION: Proposed rule; request for comments.

SUMMARY: The U.S. Department of Labor (DOL or the Department) proposes to rescind its regulation regarding Standards Recognition Entities (SREs) of Industry-Recognized Apprenticeship Programs (IRAPs). Specifically, the proposed rule would rescind the regulatory framework for the Department's recognition of SREs and SREs' role in recognizing IRAPs, and make necessary conforming changes to the Department's registered apprenticeship regulations.

DATES: To be ensured consideration, comments must be received on or before January 14, 2022.

ADDRESSES: You may submit written comments electronically by the following method:

• *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions on the website for submitting comments. Label all submissions with docket number ETA–2021–0007 and RIN 1205–AC06.

Instructions. Include docket number ETA–2021–0007 in your comments as well as RIN 1205–AC06.

You may submit comments, identified by docket number ETA–2021–0007 and RIN 1205–AC06, by using the Federal eRulemaking portal: *https://www.regulations.gov.* Follow the website instructions for submitting comments (under ''Help'' > ''How to use *Regulations.gov*'').

Please be advised that the Department will post all comments received that relate to this proposed rule on *https://www.regulations.gov* without making any change to the comments or redacting any information. The *https://www.regulations.gov* website is the Federal eRulemaking portal, and all comments posted there are available and accessible to the public. Therefore, the Department recommends that commenters remove personal information, such as Social Security numbers, personal addresses, telephone numbers, and email addresses, included in their comments, as such information may become easily available to the public via the *https://www.regulations.gov* website. It is the responsibility of the commenter to safeguard personal information.

FOR FURTHER INFORMATION CONTACT: Heidi Casta, Acting Administrator, Office of Policy Development and Research, U.S. Department of Labor, 200 Constitution Avenue NW, Room N–5641, Washington, DC 20210, Telephone: (202) 693–3700 (voice) (this is not a toll-free number) or 1–800–326–2577 (TDD).

SUPPLEMENTARY INFORMATION:

I. Background

The National Apprenticeship Act of 1937 (NAA), 29 U.S.C. 50, authorizes the Secretary of Labor (Secretary) to: (1) Formulate and promote the use of labor standards necessary to safeguard the welfare of apprentices and to encourage their inclusion in apprenticeship contracts; (2) bring together employers and labor for the formulation of programs of apprenticeship; and (3) cooperate with State agencies engaged in the formulation and promotion of standards of apprenticeship. 29 U.S.C. 50. The Department promulgated regulations to implement the NAA at 29 CFR part 30 (equal employment opportunity in apprenticeship) in 1963 and part 29 (labor standards for the registration of apprenticeship programs) in 1977. The part 30 regulations prohibit discrimination in registered apprenticeship based on race, color, religion, national origin, sex, sexual orientation, age (40 or older), genetic information, and disability, and they require sponsors of registered apprenticeship programs (RAPs) to take affirmative action to provide equal opportunity in such programs. The part 29 regulations set forth labor standards safeguarding the welfare of apprentices, including: Prescribing policies and procedures concerning the registration, cancellation, and deregistration of apprenticeship programs; recognizing State Apprenticeship Agencies (SAAs) as Registration Agencies; and matters relating thereto. The Department significantly updated 29 CFR part 29 in 2008 to ''increase flexibility, enhance program quality and accountability, and promote apprenticeship opportunity in the 21st century, while continuing to safeguard the welfare of apprentices'' (73 FR 64402, Oct. 29, 2008), and updated 29 CFR part 30 in 2016 ''to

modernize equal employment opportunity regulations'' (81 FR 92026, Dec. 19, 2016). These regulations provide the framework for the registered apprenticeship system.

On June 15, 2017, President Trump issued Executive Order (E.O.) 13801, ''Expanding Apprenticeships in America'' (82 FR 28229), which directed the Secretary to consider issuing regulations that promote the development of IRAPs by third parties. Section 8(b)(iii) of E.O. 13801 also established a Task Force on Apprenticeship Expansion (Task Force) to identify strategies and proposals to promote apprenticeships, to include ''the most effective strategies for creating industry-recognized apprenticeships.'' Based on E.O. 13801 and the Task Force's recommendations, the Department issued a new rule entitled ''Apprenticeship Programs, Labor Standards for Registration, Amendment of Regulations'' (IRAP rule), codified at 29 CFR part 29, subpart B, which established the IRAP system. 85 FR 14294 (Mar. 11, 2020).

The IRAP rule established a process for DOL's Office of Apprenticeship (OA) Administrator (Administrator) to recognize qualified third-party entities, known as SREs, which would, in turn, evaluate and recognize IRAPs. The IRAP rule set forth the requirements for third-party entities applying for Departmental recognition as SREs. It also identified certain requirements apprenticeship programs must meet in order to obtain recognition from SREs as IRAPs. The IRAP rule was published on March 11, 2020, and went into effect on May 11, 2020. As of the date of this proposed rule, the Department has recognized 27 SREs, which have, in turn, recognized 175 IRAPs, with 165 of these programs recognized by a single SRE.

On February 17, 2021, President Biden issued E.O. 14016, ''Revocation of Executive Order 13801'' (86 FR 11089), which in section 2 directed Federal agencies to ''promptly consider taking steps to rescind any orders, rules, regulations, guidelines, or policies'' implementing E.O. 13801.

Pursuant to E.O. 14016, on February 17, 2021, the Department announced it would be undertaking a review of the IRAP system and as a result suspended the acceptance of new applications to become a recognized SRE and suspended making final determinations for organizations that had already submitted an application to become a recognized SRE.[1] The Department advised that all SREs already approved by the Department and all IRAPs recognized by an SRE could continue to perform their functions as described in the regulation, to include the recognition of new IRAPs.

The Department's review of the IRAP system and proposed rescission of the IRAP rule has been informed by the Administration's priority to create jobs ''to be filled by diverse, local, well-trained workers who have a choice to join a union'' through strengthening RAPs.[2] The Department is focused on rebuilding the middle class, connecting a diverse workforce to family-sustaining jobs, and playing an active role in the rebuilding of the workforce to address the effects of the 2019 Coronavirus Disease pandemic in a manner consistent with its mission to ''foster, promote, and develop the welfare of the wage earners, job seekers, and retirees of the United States; improve working conditions; advance opportunities for profitable employment; and assure work-related benefits and rights.'' [3] As such, the Department plays an important role in ensuring workers are paid a fair wage, provided a safe workplace, and provided the tools and training necessary to access equitable economic opportunity and success. This mission is always important, but even more so as the country emerges and begins to recover from the 2019 Coronavirus Disease pandemic.[4] The pandemic has led to millions of workers becoming unemployed, and it has exposed vulnerabilities and fissures in our economy as a result of systemic racism and economic inequality, of which the burdens were felt greatest by low-wage earners and communities of color. The Department views the registered apprenticeship system—a system that has benefited thousands of workers and employers throughout its existence—as a far more effective system than IRAPs for delivering on DOL's mission to help workers access family-sustaining jobs, protect the safety and welfare of apprentices, and reach out to underserved communities.

The IRAP rule, conversely, does not align with the Administration's and Department's priorities for several reasons, as discussed in further detail below. Among them is that IRAPs have fewer quality training and worker protection standards than RAPs and, contrary to the conclusions in the IRAP rule, the Department no longer considers it appropriate or necessary to create an additional apprenticeship model, particularly one that does not guarantee the same protections for apprentices. The IRAP rule also threatens to undermine the robust and successful registered apprenticeship system by creating a duplicative system that lacks sufficient oversight and quality necessary to ensure the Department endorses programs meeting the needs of the American workforce and economy. Although the IRAP rule was premised on the idea that parallel apprenticeship systems were preferable as a means to better grow apprenticeship generally, upon further consideration and review the Department thinks that the existence of two parallel systems overseen by the Department is an inefficient and ineffective use of its resources.

In the IRAP rule, IRAPs were touted as a more flexible, industry-driven model that would enable expansion of apprenticeship into new industries and occupations. However, as explained in greater detail below, the Department has reconsidered this conclusion and now thinks that the IRAP rule is redundant and not necessary to broaden the scope of apprenticeship coverage by industry. In addition, upon review the Department now thinks that the IRAP rule does not provide adequate focus on worker needs and protections, does not ensure adequate program quality standards, does not provide sufficient equal employment opportunity protections for apprentices, and does not provide a proven pathway to family-sustaining jobs.

The Department therefore believes that focusing its efforts and resources on expanding the registered apprenticeship system will more effectively meet the needs of industry and workers alike, and has concluded that the best path forward is to rescind the IRAP rule and focus on further strengthening the successful registered apprenticeship system.

[1] *https://www.dol.gov/newsroom/releases/eta/eta20210217.*

[2] White House, ''Fact Sheet: Biden Administration to Take Steps to Bolster Registered Apprenticeships'' (Feb. 17, 2021), available at *https://www.whitehouse.gov/briefing-room/statements-releases/2021/02/17/fact-sheet-biden-administration-to-take-steps-to-bolster-registered-apprenticeships/.*

[3] *https://www.dol.gov/general/aboutdol.*

[4] The IRAP rule was published on March 11, 2020, which is the same day that the World Health Organization declared COVID–19 a pandemic and 2 days before the President declared a national emergency concerning the COVID–19 pandemic. See World Health Organization Director General's opening remarks at the media briefing on COVID–19 (Mar. 11, 2020), available at *https://www.who.int/director-general/speeches/detail/who-director-general-s-opening-remarks-at-the-media-briefing-on-covid-19---11-march-2020;* Proclamation 9994, Declaring a National Emergency Concerning the Novel Coronavirus Disease (COVID–19) Outbreak, 85 FR 15337 (Mar. 13, 2020). The declaration of a national emergency continues as of the date of the publication of this proposed rule. Continuation of the National Emergency Concerning the Coronavirus Disease 2019 (COVID–19) Pandemic, 86 FR 11599 (Feb. 24, 2021).

II. The Registered Apprenticeship System is Highly Successful for Industry

For over 80 years, the registered apprenticeship system has met the demands from industry to provide quality work-based training. RAPs combine paid on-the-job learning (OJL) with related instruction to progressively increase workers' skill levels and wages. With this ''earn and learn'' model, apprentices are employed and earn wages from the first day on the job. Industries that have adopted RAPs as part of their work-based learning models have cited the standards, skillsets, and retention offered by skilled workers associated with RAPs as advantageous to their bottom line. In one survey, nearly three-fourths of surveyed employers stated that registered apprenticeships drove increased worker productivity.[5] RAPs are a flexible training strategy that can be customized to meet the needs of any business, including allowing employers to partner with workforce partners and educators to develop and apply industry standards to training programs, thereby increasing the quality and productivity of the workforce.

A skilled workforce is foundational to a strong economy, and registered apprenticeship provides a proven avenue by which to deliver much needed talent development to various industry sectors, including as the economy recovers from the disruption cause by the COVID–19 pandemic. Employers have continued to turn to registered apprenticeship to hire and train new employees, with over 221,000 new registered apprentices over the past year across several industries, including cybersecurity, healthcare, advanced manufacturing, transportation, energy, and information technology (IT).[6]

This growth is not an anomaly. Since its establishment, the registered apprenticeship system has, with few exceptions, shown strong growth. The past 5 years saw the creation of over 13,500 new RAPs. In 2020 alone, there were nearly 26,000 RAPs active across the nation, and 3,143 new apprenticeship programs were established nationwide, representing 73-percent growth from 2009 levels.[7] Despite the COVID–19 pandemic, 2020 represents the third-highest year of new RAP development over the past decade. As a result of these programs, more than 221,000 new workers became apprentices in 2020. In total, there were over 636,000 apprentices across the Nation who were obtaining skills while earning the wages they need to build financial security, and over 80,000 apprentices have successfully completed their program and received a certificate of completion recognized by industries across the Nation.[8] Apprentices who have successfully completed their program and received their certificate of completion have high career retention rates, with over 94 percent of graduates retaining employment.[9] The continued, sustained growth of registered apprenticeship demonstrates it remains a trusted and successful framework that industry can leverage to develop and retain a skilled workforce.

The Department expects this broad-based growth to continue as the registered apprenticeship system is an important part of the Administration's workforce development strategy, including its COVID–19 recovery strategy in which registered apprenticeship can provide a bridge to businesses to an economic recovery. Thus, registered apprenticeship has been, and will continue to be, an important long-term education and talent development strategy for all workers, and in turn for industry.

III. The Registered Apprenticeship System is Highly Successful for Workers

In addition to the demonstrated success of the registered apprenticeship system as a workforce training model for industry, it has proven to be highly successful and beneficial to workers because of its emphasis on both high-quality training and apprentice safety and welfare. Registered apprenticeship is designed to ensure high-quality training through mentorship, OJL, and related instruction while also prioritizing safety, wage progression, and equal employment opportunity for apprentices. Registered apprenticeships follow federally approved industry standards for workplaces, and programs must abide by set ratios for supervision to further enhance safety in the program. During training, apprentices are guaranteed progressive wage increases, and research shows that Registered Apprenticeship program completers earn over $300,000 (including benefits) more over their lifetimes as compared with individuals who do not complete a registered apprenticeship.[10] Further, the Department has taken significant steps to increase the participation of women and individuals from underrepresented groups through the robust requirements in 29 CFR part 30. With registered apprenticeship, there is also an added level of accountability because the Department can exercise its enforcement authority to intervene and ensure employers provide industry-established prevailing wages, ensure stringent safety standards are in place, and monitor program quality to protect workers.

In contrast, the IRAP model was designed in a way that does not incorporate these same benefits and protections. IRAPs do not ensure that programs uniformly produce a high quality of training recognized across the Nation, are not designed to promote and advance diversity in the apprenticeship system, and do not include the same apprentice safety and welfare requirements as the RAP model. The IRAP model was designed as a hands-off approach, requiring SREs to play the primary role in program monitoring and intervention. The Department no longer views this as a reasonable or effective alternative to the standards and oversight that are the hallmarks of the registered apprenticeship system. While SREs are responsible for establishing and enforcing the individual standards of the programs under their purview, each SRE may have differing standards and views on acceptable levels for performance. For example, IRAPs' lack of uniform requirements regarding a progressively increasing wage, enhanced safety standards, and affirmative action goals mean there is no

[5] Urban Institute Research Report, ''The Benefits and Challenges of Registered Apprenticeship: The Sponsors' Perspective'' (June 12, 2009), available at *https://www.urban.org/research/publication/benefits-and-challenges-registered-apprenticeship-sponsors-perspective.*

[6] The 25 federally administered States and 18 federally recognized SAAs use the Employment and Training Administration's Registered Apprenticeship Partners Information Database System (RAPIDS) to provide individual apprentice and sponsor data. These data represent registered apprenticeship national results for Fiscal Year (FY) 2020 (Oct. 1, 2019–Sept. 30, 2020), as reported by these entities, and are available at *https://www.dol.gov/agencies/eta/apprenticeship/about/statistics/2020.*

[7] OA 2020 Data and Statistics, available at *https://www.dol.gov/agencies/eta/apprenticeship/about/statistics/2020.*

[8] OA 2020 Data and Statistics, available at *https://www.dol.gov/agencies/eta/apprenticeship/about/statistics/2020.*

[9] OA Career Seeker Fact Sheet (Sept. 2020), available at *https://www.apprenticeship.gov/sites/default/files/Career_Seeker_Fact_Sheet.pdf.*

[10] See, *e.g.,* Mathematica Policy Research, ''An Effectiveness Assessment and Cost-Benefit Analysis of Registered Apprenticeship in 10 States: Final Report'' (July 25, 2012), *https://wdr.doleta.gov/research/FullText_Documents/ETAOP_2012_10.pdf.* The study cautions against interpreting its results, which do not control for unobservable skill or motivation, as having conclusively identified the effects of registered apprenticeships on earnings. Moreover, the estimates do not represent increments between registered apprenticeships and IRAPs (the latter not having been implemented at the time the study was conducted).

uniformity across different IRAPs and SREs.

This is fundamentally inconsistent with the Department's goal of expanding quality apprenticeships in a manner that both ensures a high level of quality while also retaining industry input and flexibility to adapt the apprenticeship model to different industries and occupations. RAPs—which can be, and have been, adapted to different occupations and are recognized for their high quality and effective worker protections—have proven effective in striking an appropriate balance between the structure necessary to ensure high-quality training and the flexibility necessary to adapt the apprenticeship model to different industries and occupations. Further, the Department's ability to intervene to address disparities in quality and worker protections across IRAPs is limited because the Department does not have the ability to directly monitor or oversee IRAPs, and such disparities may cause confusion for apprentices and promote inequitable outcomes among program participants.

A. Registered Apprenticeships Uniformly Provide More Rigorous, Higher Quality Training

As described further below, registered apprenticeships must adhere to rigorous training requirements, to include OJL and related instruction. When compared to registered apprenticeships, IRAPs do not have the same standards for minimum skill level or competency baselines in their respective occupations.

1. On-the-Job Learning

A structured OJL model is a hallmark of a high-quality apprenticeship program, as this framework provides standardized evaluation of apprentice proficiency using a time-based model, competency-based model, or a hybrid of both, with benchmarks that ensure mastery in the apprentice's respective occupation and flexibility in the approach used that ensures apprenticeships can be developed and customized to a variety of occupations. Registered apprenticeships generally require a minimum of 2,000 hours (or 1 year) of OJL for time-based and hybrid programs. Registered apprenticeships can also be measured against skills-based competencies, and the amount of OJL typically amounts to 1 year but may take more or less time depending on the individual. The standardized approach to OJL employed in registered apprenticeships ensures apprentices have the necessary time, within a structured framework, to apply their skills and training in practice and apprentices meet minimum skill level or competency baselines before entering the workforce. Further, registered apprenticeships are assessed based, in part, on whether OJL is available for all phases of an apprentice's training. Because OJL is a critical component for the apprentice's learning experience, the Department considers a structured mentorship requirement as a strength for high-quality apprenticeship programs. Registered apprenticeships pair apprentices with experienced employees (also referred to as Journeyworkers) who have already mastered the skills and competencies associated with the occupation such that these individuals can mentor apprentices with on-the-job guidance and direction that ensures safety and quality training.

In contrast, IRAPs are not required to have a robust, structured OJL model. Instead, IRAPs need only follow the written training plan established by the SRE—a plan that has no requirements other than that it be formulated using consensus-based competency standards. Because not all IRAPs provide the same structured, standardized framework for OJL as RAPs, the quality of training can vary across SREs and, in turn, IRAPs. As a result, apprentices participating in IRAPs may lack access to rigorous, structured OJL—a critical component of a high-quality apprenticeship program because it equips registered apprentices to enter the workforce. Although the training provisions of the IRAP rule were based on the assumption that SREs are in the best position to establish OJL frameworks, the Department now views this lack of uniformity in OJL as inconsistent with the goal of growing a highly skilled workforce through apprenticeship as it could too easily lead to apprenticeship programs that do not provide sufficient training to apprentices. The Department thinks that the existing OJL models available under the registered apprenticeship system—which can be adapted to different occupations and are recognized for their high quality and effective worker protections—have proven effective in striking an appropriate balance between the structure necessary to ensure high-quality training and the flexibility necessary to adapt the apprenticeship model to different industries and occupations.

2. Related Instruction

As important as OJL is the related instruction [11] component of an apprenticeship program. By requiring related instruction as part of registered apprenticeship, the Department ensures employers are equipping apprentices with the theoretical and technical knowledge in subjects related to their respective occupations. This is essential to a high-quality apprenticeship program, and it is the Department's priority that minimum related instruction standards are integrated into the apprenticeship programs it recognizes. A minimum of 144 hours of related instruction is recommended for registered apprenticeships, and recognizing the benefit of robust related instruction, most registered apprenticeships exceed the 144-hour recommendation. This approach ensures apprentices uniformly receive meaningful and substantive knowledge in their respective occupations, creating a well-rounded training experience that provides the educational foundation necessary for success in practical settings, while also retaining flexibility based on different industries and occupations that may require varying amounts of related instruction.

In contrast, the IRAP requirements lack standards on minimum related instruction hours, and do not articulate how SREs monitor or evaluate related instruction. As a matter of design, apprentices in an IRAP may lack access to this key component of a high-quality apprenticeship program and apprentices and the program therefore may not provide sufficient educational experiences for the foundational knowledge that is necessary in their occupations. In the IRAP rule, the Department viewed SREs as best-placed to develop the standards and frameworks on related instruction, but it no longer finds this approach consistent with the goal of expanding high-quality apprenticeships. Instead the Department finds that the conspicuous absence of minimum standards and an articulated approach to evaluation for related instruction in IRAPs means the Department cannot uniformly ensure apprentices in those programs receive the theoretical and technical knowledge necessary in their respective occupations, which is a hallmark of a high-quality apprenticeship program and necessary to developing a highly skilled workforce. Accordingly, the Department cannot ensure IRAPs are

[11] "Related instruction" is an organized and systematic form of instruction designed to provide the apprentice with the knowledge of the theoretical and technical subjects related to the apprentice's occupation. Such instruction may be given in a classroom, through occupational or industrial courses, or by correspondence courses of equivalent value, electronic media, or other forms of self-study approved by the Registration Agency. 29 CFR 29.2.

providing the quality of related instruction necessary to ensure apprentices are competent in these occupations, which conflicts with the Department's goal of expanding high-quality apprenticeships.

B. Registered Apprenticeships Provide Better Safety and Welfare Protections

The importance of apprentice safety and welfare cannot be overstated. As discussed further below, the registered apprenticeship system includes requirements related to safety, equal employment, progressive wages, and other worker protections that provide apprentices with meaningful employment opportunities while also guaranteeing rights and protections on the job.

In contrast, the requirements of the IRAP rule fall short in these areas. As discussed further below, the requirements include basic compliance with existing laws but do not create additional obligations that focus on safeguarding the welfare of apprentices, especially with respect to progressively increasing wages, safety requirements, and equal employment opportunity (EEO). The IRAP rule also dilutes the Department's role in overseeing apprenticeships, tasking SREs with this oversight role instead and retaining only a minimal role in overseeing the SREs.

1. Workplace Safety

Enhanced safety standards are an essential element of a successful apprenticeship program. While the additional requirements of RAPs are designed to keep apprentices safe, this does not mean each RAP requires the same training or same safety precautions—these are workplace- and industry-specific requirements within the framework of the registered apprenticeship system.

RAPs require several safety protections designed to both teach apprentices how to work safely within their occupation and create safe workplaces for apprentices. RAPs must specify a numeric ratio of apprentices to Journeyworkers ''consistent with proper supervision, training, safety, and continuity of employment.'' 29 CFR 29.5(b)(7). They must also have ''[a]dequate and safe equipment and facilities for training and supervision'' in addition to ''safety training for apprentices on the job and in related instruction.'' 29 CFR 29.5(b)(9). Though broad, these safety requirements focus on both physical workplace safety and safety through training and mentorship. Further, they are meant to protect the safety of apprentices in each RAP by being tailored to the specific conditions in which those apprentices will be working and learning.

In contrast, IRAPs are not necessarily covered by enhanced safety standards beyond generally applicable Federal, State, and local safety laws and regulations and any additional safety requirements of the SRE. While a SRE may require an IRAP to have stricter, more tailored safety standards than required by applicable law, this discretionary requirement is insufficient to protect the safety of apprentices who, by definition, are being trained on the job and therefore would benefit from additional workplace protections, particularly for less skilled workers training in occupations that pose a higher risk of injury or death. Although the safety provisions of the IRAP rule were based on the assumptions that SREs would be able to better determine the safety standards relevant to their IRAPs and that compliance with generally applicable workplace safety standards was a sufficient baseline requirement, the Department now disagrees with leaving such a determination to the SRE, especially without the important safety parameters requirements of the registered apprenticeship system. The registered apprenticeship regulations require a ratio of apprentices to journeyworkers, safe equipment and facilities for training and supervision, and the provision of safety training on the job and in related instruction. However, the registered apprenticeship regulations do not prescribe how to meet these requirements, leaving sufficient flexibility for implementation. This ensures a process for taking into consideration both industry needs and apprentice safety that is not present in the IRAP rule. The Department views this as the more appropriate approach given that apprentices are learning on the job and therefore benefit from enhanced training and protections.

2. Progressive Wages

It is a priority of the Department to grow opportunities to help workers access family-sustaining jobs. Registered apprenticeship's earn-as-you-learn model accomplishes this priority by providing for progressively increasing wages for apprentices as they progress in their apprenticeship experience, learning, and skills. In registered apprenticeship, the graduated scale of wages and any compensation for related instruction is set forth in the apprenticeship agreement required for each apprentice. Not only is this type of wage progression guaranteed per the terms of the apprenticeship agreement, but it also serves as an important incentive to attract apprentices and sets them on a path to potential lifetime earnings (including benefits) that, according to research, exceed by more than $300,000 those who do not complete a registered apprenticeship.[12]

In contrast, there is no such guaranteed wage progression for apprentices of IRAPs—an apprentice could be earning the same wages over the course of the apprenticeship, and any wage progression is solely at the discretion of the IRAP. Because the IRAP regulation is silent on one of the most valuable features of apprenticeship to apprentices, there is no requirement for SREs to play any role in an IRAP's wage-setting, other than to affirm compliance with applicable laws, such as minimum wage. Although the IRAP rule is premised upon the assumption that market forces and apprentice choice will drive wage decisions, the Department notes that RAP wages are also influenced by market forces and apprentice choice, including an apprentice's option to enroll in a RAP where a progressive wage is required. The important difference is the prioritization of wage increases commensurate with skill increases, which is in line with the Department's priorities to help workers access family-sustaining jobs and the idea that apprentices should be paid a wage commensurate with the skills they have attained.

3. Equal Employment Opportunity

The Department views equity and equal opportunity as essential to the success of an apprenticeship program, and it notes its responsibility under E.O. 13985, ''Advancing Racial Equity and Support for Underserved Communities Through the Federal Government,'' 86 FR 7009 (Jan. 20, 2021), to advance equity, civil rights, racial justice, and equal opportunity. Such a responsibility necessitates action, intentional infusion of equity into workforce development programs, and critical thinking about how to reduce barriers to workforce entry. The registered apprenticeship system's 29 CFR part 30 regulations acknowledge that mere passive nondiscrimination is insufficient and

[12] See, *e.g.,* Mathematica Policy Research, ''An Effectiveness Assessment and Cost-Benefit Analysis of Registered Apprenticeship in 10 States: Final Report'' (July 25, 2012), *https://wdr.doleta.gov/research/FullText_Documents/ETAOP_2012_10.pdf.* The study cautions against interpreting its results, which do not control for unobservable skill or motivation, as having conclusively identified the effects of registered apprenticeships on earnings. Moreover, the estimates do not represent increments between registered apprenticeships and IRAPs (the latter not having been implemented at the time the study was conducted).

require affirmative steps to promote diversity and equity in apprenticeship. 29 CFR 30.3, 30.4. Accordingly, the registered apprenticeship system has structured and specific requirements regarding equal opportunity, anti-harassment, affirmative action, utilization analyses and goals, targeted recruitment, outreach and retention, compliance, and enforcement. Through the equal opportunity regulations at 29 CFR part 30, the registered apprenticeship system provides enhanced opportunities for apprentices to access and succeed in RAPs and gives sponsors tools to reduce barriers to equal opportunity within their programs.

In contrast, the IRAP model simply requires programs to affirm their adherence to applicable Federal, State, and local laws and regulations pertaining to EEO. 29 CFR 29.22(a)(4). Requiring IRAPs to do the bare minimum, especially when a model framework for EEO in apprenticeship is already in place in 29 CFR part 30, is a disservice to apprentices and apprenticeship programs, and contrary to the goals of the Department to promote equity in apprenticeship. Although the SREs do have minimal additional responsibilities to develop policies requiring IRAP adherence to EEO law, facilitating such adherence, and reflecting comprehensive outreach strategies to reach diverse populations that may participate in IRAPs, the IRAP rule lacks specific requirements and provides no framework for equity principles or goals. 29 CFR 29.22(i). The requirements of the IRAP model fail to ensure meaningful action will be taken to expand equal employment opportunity in apprenticeship.

4. Worker Empowerment

The Department generally thinks the relationship between workers and employers must be balanced so workers have a voice in ensuring fair and safe work conditions. For registered apprentices, there are many avenues to realize worker empowerment. The apprenticeship agreement plays a crucial role in articulating the standards of apprenticeship and the terms and conditions of employment. The registered apprenticeship agreement must contain specific terms, including a statement of the occupation for which the apprentice is training, the duration of the apprenticeship, the number of hours in the program to include related instruction hours, the schedule of work processes, the graduated scale of wages to be paid, the standards of the apprenticeship program, and an EEO statement. 29 CFR 29.7. The registered apprenticeship agreement must also contain information about dispute resolution should a controversy or difference arise out of the agreement, *id.,* and must be accepted and recorded either by OA or an SAA. 29 CFR 29.2. The requirement that registered apprenticeship agreements include specific terms ensures the apprentices have knowledge of their rights and responsibilities and empowers them to be informed participants in the employment relationship.

Although IRAPs also contain a written apprenticeship agreement requirement, each IRAP may determine which terms and conditions to include as long as the agreement is consistent with the SRE's requirements. Each SRE may determine its own requirements as it sees fit, potentially creating a wide variety in apprenticeship agreements across SREs and no requirement for a uniform set of terms and conditions for apprentices. There is also no requirement to submit the agreement to be accepted or recorded by the SRE. Without parameters, this requirement contains little more than an honor system to ensure apprentices have meaningful information about the terms and conditions of their apprenticeship and how they can voice their concerns.

One of the key justifications of the 2020 rule was that the IRAP model would help address a purported ''skills gap'' in the labor market. While providing training to job seekers is a key component to addressing any ''skills gaps'' or ''skills mismatches,'' evidence suggests that training alone is not the answer. Employer investments in workforce development, competitive and rising wages to attract and retain workers, commitments to opportunity and diversity, and worker empowerment are key factors to addressing industry labor needs.[13] [14] The well-established RAP model—with its role in and focus on employer investment in training, specific equal employment opportunity recruitment requirements and protections for apprentices, as well as its requirement that a progressive wage (beyond the minimum wage) be paid to apprentices during their apprenticeship reflecting their acquisition of occupational and workplace competencies, and worker empowerment and safety provisions—provides a more promising and effective framework for addressing and closing persistent inefficiencies in the labor market.

Conversely, the very deficiencies inherent to the IRAP model discussed above—workplace safety, progressive wages, equal employment opportunity, and worker empowerment—severely reduce the ability of IRAPs to address any current or future labor shortages that might exist. Job quality is key to recruiting, training, and retaining workers in a specific occupation or industry.[15] [16] Thus, the lack of requirements for IRAPs to address these critical issues limits their ability to help fulfill labor market demands.

IV. The IRAP System is Redundant of the Registered Apprenticeship System

One of the main justifications behind the development of IRAPs was the necessity to grow and expand apprenticeship into industries and occupations that have traditionally not used the registered apprenticeship system because of the insufficient flexibility in program requirements within RAPs to meet the varying needs of different industries and the administrative burden posed by these requirements. However, the premise that registered apprenticeship is too inflexible to meet the needs of industry is fundamentally flawed and contrary to the above-mentioned demonstrated success of registered apprenticeship for industry and workers and its continued growth in expanding into new industries and occupations. Although registered apprenticeship has historically been associated with the construction sector, it has successfully been adopted across a diverse range of industry sectors, with significant growth in recent years.

The Department has used a variety of strategies to drive registered apprenticeship growth beyond those industries historically associated with registered apprenticeship. One strategy driving this expansion and growth is the Industry Intermediaries concept, where the Department has used contracted entities with specific industry expertise to further the Department's efforts to

[13] Annelies Goger and Luther Jackson, ''The labor market doesn't have a 'skills gap'—it has an opportunity gap,'' Sept. 9, 2020, *https://www.brookings.edu/blog/the-avenue/2020/09/09/the-labor-market-doesnt-have-a-skills-gap-it-has-an-opportunity-gap/.*

[14] Kate Bahn, '' 'Skills gap' arguments overlook collective bargaining and low minimum wages,'' May 9, 2019, *https://equitablegrowth.org/skills-gap-arguments-overlook-collective-bargaining-and-low-minimum-wages/.*

[15] Livia Y. Lam, ''A Multiple Measures Approach to Workforce Equity: How Improving Job Quality in Workforce Accountability Can Help Close Equity Gaps,'' Center for American Progress, October 20, 2020, at: *https://www.americanprogress.org/issues/economy/reports/2020/10/20/491998/multiple-measures-approach-workforce-equity/.*

[16] Society for Human Resource Management (SHRM), ''Managing for Employee Retention,'' 2017, at: *https://www.shrm.org/resourcesandtools/tools-and-samples/toolkits/pages/managingforemployeeretention.aspx.*

expand registered apprenticeship opportunities in high-growth sectors. From 2016 to 2020, Department-contracted Industry Intermediaries created 271 new RAPs in 232 high-demand occupations for a total of 867 employers. Of the occupations developed under these contracts, 37 percent were in the manufacturing sector, 15 percent were in the healthcare sector, and 15 percent were in the transportation sector.[17]

Another strategy that has helped expand registered apprenticeship is the Department's 2015 American Apprenticeship Initiative (AAI), which aimed to register new apprentices in high-growth and high-tech industries, such as health care, IT, and advanced manufacturing, especially from populations traditionally underrepresented in apprenticeship, including women and people of color. AAI grantees, which included labor unions, industry associations, local workforce boards and nonprofit organizations, have successfully expanded the RAP model into new industries and extended to more diverse populations. As of June 2020, the 44 AAI grantees initiated 2,019 new programs and registered 24,675 apprentices, of which 14,486 were from underrepresented populations.[18] This use of targeted investments and intermediaries to extend registered apprenticeship to new industry sectors and occupations, as well as underrepresented populations, undermines the rationale for the IRAP system and underscores the redundant and duplicative aspect of the IRAP model.

More broadly, the expansion of registered apprenticeship into ''non-traditional'' industry sectors where IRAPs are operating and for which SREs have been certified demonstrates that the IRAP effort is superfluous and not a good use of government resources that could support the proven activities already underway. Based on Federal program data from 2019 and 2020, which were unavailable at the time the IRAP rule was issued, the health care and social assistance industry sector saw an 18-percent rise in the number of active RAPs.[19] Similarly, the information industry sector saw a 31-percent increase in the number of active RAPs during this same period, while the manufacturing industry sector saw a 14-percent increase in the number of active RAPs, as well. Within the same time frame, equally impressive growth has taken place in the following industry sectors not historically associated with the registered apprenticeship system: Accommodation and food services (31 percent); arts, entertainment and recreation (45 percent); finance and insurance (39 percent); professional, scientific and technical services (41 percent) and transportation and warehousing (19 percent).[20] Based on the most recent data, and in conjunction with historical data about registered apprenticeship's steady growth, the Department is departing from the IRAP rule's assertion that IRAPs are necessary for expansion of apprenticeship into non-traditional occupations. Instead, the Department is convinced that the registered apprenticeship system is capable of effectively and efficiently expanding into non-traditional occupations, while at the same time maintaining high-quality labor standards. This expansion demonstrates that the design of the registered apprenticeship system is capable of adapting successfully to a wide range of industry needs and that registered apprenticeship's requirements on industry set forth important parameters for the successful growth of apprenticeship programs without being overly burdensome.

The Department's actual experience administering the IRAP system highlights the duplicative nature of the two systems. There is clear overlap between the occupations that SREs were approved to recognize IRAPs in and the occupations the Department has determined are appropriate for the registered apprenticeship system. A majority of the occupations in the IRAP system are occupations that have already been deemed as apprenticeable under the registered apprenticeship system. Similarly, the top five occupations in the IRAP system (machinist; maintenance workers, machinery; manufacturing production technicians; information security analysts; and web developers) all are currently regarded as apprenticeable occupations and used within the registered apprenticeship system. Moreover, comparing the approved occupations for IRAP SREs with currently apprenticeable occupations in registered apprenticeship shows a majority of the top 20 occupations recognized by industry for training under the IRAP model have been determined suitable under the registered apprenticeship system.[21] The concurrent recognition of these occupations as both IRAPs and registered apprenticeship occupations is likely to lead to confusion and disparate outcomes, particularly as it allows a single entity to simultaneously operate as an SRE or IRAP and sponsor a RAP, with the IRAP allowed to provide lower quality training and fewer worker protections. This result is unquestionably a poor use of government resources because it imposes duplicative costs to the government to support a redundant program that may not be advancing the Department's mission and goals for apprenticeship. Furthermore, it is likely to sow confusion among prospective apprentices and employers, who will struggle to understand how they should interact with these duplicative systems.

V. The Effect of the Department's Proposed Rescission of the IRAP Rule

As discussed above, the Department has determined that the establishment of a duplicative and parallel IRAP system will not ensure access to high-quality job skills and training to American workers, while at the same time safeguarding the welfare of apprentices. Accordingly, the Department believes that the IRAP system is not a prudent use of Government resources, would diminish the quality and coherence of American apprenticeship efforts, and would not allow the Department to ensure that employers, prospective apprentices, or the general public are effectively served. The Department also determined that amending the IRAP rule would not solve any of these issues. As discussed in detail above, registered apprenticeship provides for apprentice safety and welfare and continues to grow apprenticeship opportunities without sacrificing crucial requirements for quality or worker protections. Amending the IRAP rule to align with the Department's goals and priorities so

[17] National Industry and Equity Apprenticeship Intermediaries Fact Sheet, ''Advancing Registered Apprenticeship for Business and Workers in the U.S.'' (Jan. 19, 2021), available at *https://www.apprenticeship.gov/sites/default/files/Industry-and-Equity-Intermediary-Accomplishment-Fact-Sheet.pdf.*

[18] National Governors' Association, ''Registered Apprenticeship Reimagined: Lessons Learned From the American Apprenticeship Initiative'' (Nov. 9, 2020), available at *https://www.nga.org/center/publications/registered-apprenticeship-reimagined.*

[19] OA Data and Statistics, available at *https://www.dol.gov/agencies/eta/apprenticeship/about/statistics/2020.*

[20] Federal Data: Apprenticeship Statistics by Industry for FY 2019 and FY 2020, available at *https://www.dol.gov/agencies/eta/apprenticeship/about/statistics/2019* and *https://www.dol.gov/agencies/eta/apprenticeship/about/statistics/2020.*

[21] OA Registered Apprenticeship Occupations, available at *https://www.apprenticeship.gov/apprenticeship-occupations;* OA Recognized Standards Recognition Entities, available at *https://www.apprenticeship.gov/employers/industry-recognized-apprenticeship-program/approved-standards-recognition-entities.*

that it possesses more of the qualities of the registered apprenticeship system would not serve the interests of employers and apprentices given that they already have access to the registered apprenticeship system. Further, the Department can better utilize its resources and provide better service to the public by supporting and strengthening one robust apprenticeship system that has been designed to incorporate the needs of both industry and the workforce and has a demonstrated record of successfully doing so.

The Department acknowledges this proposal would, if finalized, immediately affect current SREs, IRAPs, and any apprentices participating in IRAPs. The Department understands SREs devoted resources to developing their applications and infrastructure necessary to effectively operate for a period of 5 years, and IRAPs and their apprentices may have been drawn to the program given the indication of approval from the Department. However, the Department thinks the impact of this proposal is limited given the total number of SREs and IRAPs. Over the 9-month period between May 2020, when the IRAP rule became effective, and February 2021, when the Department paused the consideration of SRE applications, the Department received a total of 45 SRE applications, including from two organizations that resubmitted applications. Of these applications, the Department ultimately recognized 27 SREs.[22] In turn, as of September 30, 2021, the recognized SREs have only recognized a reported 175 IRAPs, with the vast majority recognized by a single SRE.[23] With respect to the potential impact of this proposed rule on apprentices that are or may become enrolled in IRAPs, because apprenticeship programs may operate even without DOL recognition, IRAP apprentices would not be precluded under this proposal from continuing their participation in such training programs. Alternatively, apprentices enrolled in IRAPs may elect instead to enroll in a RAP that provides training for their desired occupation; in such instances, they may qualify for advanced standing or credit in those registered programs.

The Department considered other options with respect to the currently recognized SREs or IRAPs, including a proposed ''sunset'' period during which SREs and IRAPs would operate for a set number of years before the Department ceased its recognition, and recasting IRAPs as Certified Work-Based Learning. However, in light of the concerns discussed above, the Department believes that rescinding the regulation, including the immediate cessation of recognition for currently recognized SREs or IRAPs, is the best approach.

If this proposal is finalized, the Department will provide technical assistance and support to SREs or IRAPs who are interested in becoming program sponsors or intermediaries under the registered apprenticeship system. Similarly, as a component of the Department's technical assistance to SREs, the Department will provide SREs with information and resources the SREs can share with any IRAP apprentices who may seek placement in a RAP.

Although the Department recognizes that immediate rescission of the rule, if finalized, will likely have minimal impact, the Department seeks comments on how to address the effects of the proposed immediate cessation of recognition on SREs, IRAPs, and IRAP apprentices, including comments on the alternatives considered, but ultimately not adopted, by the Department.

VI. Regulatory Analysis and Review

A. Executive Orders 12866 (Regulatory Planning and Review) and 13563 (Improving Regulation and Regulatory Review)

Under E.O. 12866, the Office of Management and Budget's (OMB) Office of Information and Regulatory Affairs determines whether a regulatory action is significant and, therefore, subject to the requirements of the E.O. and review by OMB. See 58 FR 51735 (Oct. 4, 1993). Section 3(f) of E.O. 12866 defines a ''significant regulatory action'' as an action that is likely to result in a rule that: (1) Has an annual effect on the economy of $100 million or more, or adversely affects in a material way a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities (also referred to as economically significant); (2) creates serious inconsistency or otherwise interferes with an action taken or planned by another agency; (3) materially alters the budgetary impacts of entitlement grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or (4) raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the E.O. *Id.* This proposed rule is an economically significant regulatory action under section 3(f) of E.O. 12866.

E.O. 13563 directs agencies to propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs; the regulation is tailored to impose the least burden on society, consistent with achieving the regulatory objectives; and in choosing among alternative regulatory approaches, the agency has selected those approaches that maximize net benefits. E.O. 13563 recognizes that some benefits are difficult to quantify and provides that, where appropriate and permitted by law, agencies may consider and discuss qualitatively values that are difficult or impossible to quantify, including equity, human dignity, fairness, and distributive impacts.

1. Preliminary Economic Analysis

E.O. 14016, ''Revocation of Executive Order 13801,'' instructed the Director of OMB and the heads of executive departments and agencies to ''promptly consider taking steps to rescind any orders, rules, regulations, guidelines, or policies, or portions thereof, implementing or enforcing'' E.O. 13801. Accordingly, the Department identified for review the IRAP rule published on March 11, 2020. The Department is issuing this proposed rule because the Department has determined that a single apprenticeship system, namely, the registered apprenticeship system, would provide clearer messaging and more consistent outcomes than two parallel apprenticeship systems that would likely lead to disparate outcomes and incur duplicative costs.

In accordance with the regulatory analysis guidance articulated in OMB Circular A–4 and consistent with the Department's practices in previous rulemakings, this regulatory analysis focuses on the likely consequences of the proposed rule. The Department anticipates that the proposed rule would result in cost savings for SREs and IRAPs since they would no longer need to comply with the provisions of the March 2020 rule.

The Department has estimated the cost savings of the proposed rule relative to the existing baseline (*i.e.,* 27 SREs and 175 IRAPs). The analysis covers 10 years to ensure it captures the major cost savings that are likely to accrue over time. The Department expresses the quantifiable impacts in 2020 dollars and uses discount rates of

[22] Applications Received by the Department of Labor for Standards Recognition Entities. Approved SREs published at *https://www.apprenticeship.gov/employers/industry-recognized-apprenticeship-program/approved-standards-recognition-entities.*

[23] According to the IRAP Program and Performance Reporting System, as of September 30, 2021, of the 175 IRAPs approved, 165 were recognized by the same SRE.

3 and 7 percent, pursuant to OMB Circular A–4. The Department also considered an alternative baseline in which the Department's February 17th suspension of consideration of SRE applications was temporary and would be removed. That analysis is discussed qualitatively in the Total Cost Savings section below.

a. Number of SREs, IRAPs, and Apprentices

To calculate the annual cost savings, the Department first needed to estimate the number of SREs and IRAPs over the 10-year analysis period. The Department used the number of SREs (27) and the number of IRAPs (175) as of September 30, 2021, for this analysis.

The Department does not have data on the number of apprentices per IRAP because that information is not due from SREs until 45 days after the end of FY 2021, which will be November 15, 2021. One calculation in the March 2020 rule was based on the number of apprentices: IRAPs' preparation and signing of written apprenticeship agreements, which was estimated at 10 minutes per apprentice. Given the lack of data on the number of apprentices, this cost savings estimate should be emphasized as preliminary: If there are three apprentices per IRAP, which is the median number per RAP, and signing the written apprenticeship agreement requires 10 minutes per apprentice, then 175 IRAPs × 3 apprentices × 10 minutes × $121.08 hourly compensation adds $10,806 per year, which would increase the cost savings estimate from $9.1 million (explained below) to $9.2 million over 10 years.

b. Compensation Rates

The compensation rates used to quantify the cost savings of the proposed rule are based on the compensation rates in the IRAP rule published on March 11, 2020. The Department updated the compensation rates with 2020 data. The Department anticipates that the bulk of the workload for private sector workers would have been performed by employees in occupations similar to those associated with the following Standard Occupational Classification (SOC) codes: SOC 11–3131 (Training and Development Managers) and SOC 43–0000 (Office and Administrative Support Occupations).

According to the U.S. Bureau of Labor Statistics (BLS), the mean hourly wage rate for Training and Development Managers in May 2020 was $60.54.[24] For this analysis, the Department used a fringe benefits rate of 46 percent [25] and an overhead rate of 54 percent,[26] resulting in a fully loaded hourly compensation rate for Training and Development Managers of $121.08 [= $60.54 + ($60.54 × 0.46) + ($60.54 × 0.54)].

According to BLS, the mean hourly wage rate for Office and Administrative Support Occupations in May 2020 was $20.38.[27] The Department used a fringe benefits rate of 46 percent and an overhead rate of 54 percent, resulting in a fully loaded hourly compensation rate for Office and Administrative Support Occupations of $40.76 [= $20.38 + ($20.38 × 0.46) + ($20.38 × 0.54)].

The Department estimated the compensation rate for a Program Analyst in OA using the midpoint (Step 5) for Grade 13 of the General Schedule, which is $55.75 in the Washington, DC, locality area.[28] The Department used a fringe benefits rate of 69 percent [29] and an overhead rate of 54 percent, resulting in a fully loaded hourly compensation rate for Program Analysts of $124.32 [= $55.75 + ($55.75 × 0.69) + ($55.75 × 0.54)].

c. Time Estimates

The hourly time burdens used to quantify the cost savings of the proposed rule are based on the Department's time estimates in the IRAP rule published on March 11, 2020. The following time burdens are annual estimates.

Cost Savings Components for SREs

- Notifying the Administrator of any major change to processes or programs: 10 hours (50 percent of SREs)
- Informing the Administrator of IRAP recognition, suspension, or derecognition: 30 minutes
- Provision of data or information to the Administrator: 2 hours (10 percent of SREs)
- Provision of written attestation to the Administrator: 10 minutes per IRAP
- Disclosure of the credentials that apprentices will earn: 30 minutes
- Quality control of IRAPs: 4 hours per IRAP
- Submission of performance data to the Administrator: 4 hours per IRAP
- Making publicly available IRAP performance data: 2 hours per IRAP
- Recordkeeping: 20 hours per IRAP

Cost Savings Components for IRAPs

- Submission of performance data to the SRE: 25 hours

Cost Savings Components for the Federal Government

- Compliance assistance reviews of SREs: 10 hours per SRE (5 percent of SREs)
- Maintenance of online application form and internal review system: $125,000
- Maintenance of online resource for performance measures: $245,909
- Maintenance of online resource for list of SREs and IRAPs: $18,000

d. Total Cost Savings

[24] BLS, ''Occupational Employment and Wages, May 2020,'' available at *https://www.bls.gov/oes/current/oes113131.htm.*

[25] BLS, ''Employer Costs for Employee Compensation'' (ECEC), available at *https://www.bls.gov/ncs/data.htm.* Wages and salaries averaged $26.22 per hour worked in 2020, while benefit costs averaged $11.99, which is a benefits rate of 46 percent.

[26] U.S. Department of Health and Human Services (HHS), ''Guidelines for Regulatory Impact Analysis'' (2016), available at *https://aspe.hhs.gov/system/files/pdf/242926/HHS_RIAGuidance.pdf.* In its guidelines, HHS states, as ''an interim default, while HHS conducts more research, analysts should assume overhead costs (including benefits) are equal to 100 percent of pre-tax wages.'' HHS explains that 100 percent is roughly the midpoint between 46 and 150 percent, with 46 percent based on ECEC data that suggest benefits average 46 percent of wages and salaries, and 150 percent based on the private sector ''rule of thumb'' that fringe benefits plus overhead equal 150 percent of wages. To isolate the overhead costs from HHS's 100-percent assumption, the Department subtracted the 46-percent benefits rate that HHS references, resulting in an overhead rate of approximately 54 percent.

[27] BLS, ''Occupational Employment and Wages, May 2020,'' available at *https://www.bls.gov/oes/current/oes430000.htm.*

[28] Office of Personnel Management, ''General Schedule (GS) Locality Pay Tables,'' available at *https://www.opm.gov/policy-data-oversight/pay-leave/salaries-wages/salary-tables/pdf/2020/DCB_h.pdf.*

[29] Congressional Budget Office, ''Comparing the Compensation of Federal and Private-Sector Employees, 2011 to 2015'' (Apr. 25, 2017), available at *https://www.cbo.gov/publication/52637.* The wages of Federal workers averaged $38.30 per hour over the study period, while the benefits averaged $26.50 per hour, which is a benefits rate of 69 percent.

Exhibit 1 shows the total estimated cost savings of the proposed rule over 10 years (2022–2031) at discount rates of 3 percent and 7 percent.[30] The proposed rule is expected to have first-year cost savings of $1.3 million in 2020 dollars. Over the 10-year analysis period, the annualized cost savings are estimated at $1.3 million at a discount rate of 7 percent in 2020 dollars. In total, over the first 10 years, the proposed rule is estimated to result in cost savings of $9.1 million at a discount rate of 7 percent in 2020 dollars.

Exhibit 1: Estimated Cost Savings (2020 dollars)

	Cost Savings
First Year Total	$1,298,733
Annualized, 3% discount rate, 10 years	$1,298,733
Annualized, 7% discount rate, 10 years	$1,298,733
Total, 3% discount rate, 10 years	$11,078,458
Total, 7% discount rate, 10 years	$9,121,759

The Department also contemplated including an alternative baseline that assumed the Department's February 17th suspension of consideration of SRE applications would be removed. If the suspension were to be removed, there could be additional SREs and IRAPs in future years. OMB Circular A–4 defines a no action baseline as ''what the world will be like if the proposed rule is not adopted.'' If the world did not include this proposed rule, but included the removal of the February 17th suspension as well as decision making by potential SREs in the manner anticipated in the 2020 rule, it is possible that there would be more than 27 SREs and 175 IRAPs in each year of the analysis period. Given the potential temporary nature of the February 17th suspension, some members of the public may believe there will be an opportunity to participate in the program again in the absence of this proposed rule. Under such a scenario, 27 SREs and 175 IRAPs may be only fractions of the numbers of SREs and IRAPs that would come into existence, and perhaps those numbers would continue to grow throughout the analysis period. As such, this proposed rule would then prevent some of the eventual effects of the 2020 rule.

The Department is unable, however, to provide a quantitative analysis of this alternative baseline. The Department does not have a way to accurately estimate the number of SREs or IRAPs that would be established in the absence of this proposed rule and the removal of the February 17th suspension. Specifically, the Department is unable to estimate a reasonable growth rate for SREs over the analysis period or a realistic number of IRAPs per SRE each year. Without these two key data points, a quantitative analysis is not possible.

The Department believes that the numbers of SREs and IRAPs estimated in the 2020 rule are not an appropriate source for quantifying an alternative baseline in this proposed rule. Over the 9-month period between May 2020, when the IRAP rule became effective, and February 2021, when the Department paused the consideration of SRE applications, data indicate that participation was far lower than what was projected in the 2020 rule. To begin with, the number of SRE applications was far fewer than the number anticipated in the 2020 rule. For the 2020 rule, the Department used the number of entities that submitted grant applications under AAI grant program in FY 2016 as a guidepost for estimating the number of SRE applications. It now seems that this guidepost was unrealistic because millions of dollars were awarded to each successful AAI grant application whereas similar grant funds were not available to SREs. The lack of Federal funding may largely explain the low number of SREs (27) and IRAPs (175) compared to the numbers anticipated in the 2020 rule (203 SREs and 2,030 IRAPS in Year 1).

While the estimated number of SRE applications in the 2020 rule was based on the number of entities that submitted AAI grant applications, the estimated number of IRAPs was not based on a specific source of data because the IRAP system was a new concept in the United States. Accordingly, the Department does not have a guidepost to realistically estimate the number of IRAPs for an alternative baseline that assumes the absence of this proposed rule and the removal of the February 17th suspension.

The Department invites comments on the potential number of SREs and IRAPs in the absence of this proposed rule and the removal of the February 17th suspension. Without a reasonable way to estimate these numbers and quantify the cost savings, benefits, and transfer payments, the Department acknowledges that this proposed rule may have an annual effect on the economy of $100 million or more; therefore, this rule has been designated as an economically significant regulatory action under section 3(f) of E.O. 12866.

e. Nonquantifiable Effects

[30] The 2022 start year accounts for the time involved in the Administrative Procedure Act rulemaking process, with the final rule expected to be published in 2022.

The Department proposes rescinding the IRAP rule and, instead, refocusing efforts on expanding the registered apprenticeship system. As explained in the previous sections, the registered apprenticeship system is highly successful for industry. Industries that have adopted RAPs have cited the standards, skillsets, and retention offered by skilled workers associated with RAPs as advantageous to their bottom line. In one survey, nearly three-fourths of surveyed employers stated that registered apprenticeships drove increased worker productivity.[31] A skilled workforce is foundational to a strong economy, and registered apprenticeship provides a proven avenue by which to deliver talent development to various industry sectors.

In addition to the demonstrated success of registered apprenticeship as a workforce training model for industry, it has proven to be highly beneficial to workers because of its emphasis on high-quality training as well as apprentice safety and welfare. During training, apprentices are guaranteed wage increases, and research shows that registered apprenticeship completers earn over $300,000 (including benefits) more over their lifetimes as compared with individuals who do not complete a RAP.[32]

Registered apprenticeship has successfully been adopted across a diverse range of sectors, with significant growth in recent years. The expansion of registered apprenticeship into ''non-traditional'' sectors indicates that the IRAP effort may be superfluous and not a good use of government resources that could support the proven activities of the registered apprenticeship system.

2. Regulatory Alternatives

OMB Circular A–4 directs agencies to analyze alternatives if such alternatives best satisfy the philosophy and principles of E.O. 12866. Accordingly, the Department considered two regulatory alternatives. Under the first alternative, the Department would allow the SREs and any related IRAPs to operate with the Department's recognition for a transitional period not to exceed the previously approved 5-year period. As noted above, the approach of permitting the continued recognition of SREs and any related IRAPs would continue to temporarily retain a parallel system that does not ensure sufficient protections for apprentices, would diminish Departmental resources available for expansion of registered apprenticeship, and would generate confusion among both entities interested in establishing apprenticeship programs and the potential apprentices in such programs. This alternative would result in lower cost savings over the 10-year analysis period than the cost savings presented in Exhibit 1 because SREs and IRAPs would be obligated to follow the provisions of the IRAP rule published on March 11, 2020, for a longer period of time. Therefore, the costs of the March 2020 rule would accumulate for a longer duration and the cost savings would be delayed.

Under the second alternative, the Department would recast IRAPs as Certified Work-Based Learning. The Department considers the most effective and efficient use of its resources is to oversee a national system of registered apprenticeship that is more protective of the welfare of apprentices and that has demonstrated its capacity to grow and adapt across a range of industries and sectors. Similarly, recasting IRAPs as a type of Certified Work-Based Learning would not address the concerns identified in the discussions above regarding an indirect and insufficient oversight role for the Department in IRAPs. This alternative would also result in lower cost savings over the 10-year analysis period than the cost savings presented in Exhibit 1 because SREs and IRAPs would incur costs under the revised program. The Department cannot estimate the costs without details about the provisions of such a program. The Department invites comments on these or other possible alternatives with the goal of ensuring a thorough consideration and discussion at the final rule stage.

B. Regulatory Flexibility Act, Small Business Regulatory Enforcement Fairness Act of 1996, and Executive Order 13272 (Proper Consideration of Small Entities in Agency Rulemaking)

In accordance with the Regulatory Flexibility Act, 5 U.S.C. ch. 6 (as amended), the Department examined the regulatory requirements of the proposed rule to determine whether they would have a significant economic impact on a substantial number of small entities. As explained in the E.O. 12866 preliminary economic analysis above, the proposed rule is expected to lead to cost savings for IRAPs because these entities would no longer be required to comply with the provisions of the IRAP rule published on March 11, 2020. Cost savings for IRAPs would primarily arise from no longer needing to submit performance data to the SRE. In the March 2020 rule, the Department estimated that it would take IRAPs approximately 25 hours per year to collect and provide the relevant data. To estimate the cost savings per IRAP under this proposed rule, the Department multiplied 25 hours by the hourly compensation rate for Training and Development Managers ($121.08 per hour). The first-year cost savings per IRAP is estimated at $2,829 at a discount rate of 7 percent. The annualized cost savings per IRAP is estimated at $3,027 at a discount rate of 7 percent.

As of September 30, 2021, the number of IRAPs recognized by SREs stands at 175. Of the 175 IRAPs, 165 are in the health care industry; specifically, the vast majority of the 165 IRAPs are associated with hospitals and medical centers. As shown in Exhibit 2, the first-year and annualized cost savings for IRAPs in the hospitals subsector are not expected to have a significant economic impact (3 percent or more) on small entities of any size.

[31] Urban Institute Research Report, ''The Benefits and Challenges of Registered Apprenticeship: The Sponsors' Perspective'' (June 12, 2009), available at *https://www.urban.org/research/publication/benefits-and-challenges-registered-apprenticeship-sponsors-perspective.*

[32] See, *e.g.,* Mathematica Policy Research, ''An Effectiveness Assessment and Cost-Benefit Analysis of Registered Apprenticeship in 10 States: Final Report'' (July 25, 2012), *https://wdr.doleta.gov/research/FullText_Documents/ETAOP_2012_10.pdf.* This report categorizes reduced payments of unemployment insurance, welfare, and food stamps as benefits (separate from productivity increases) associated with registered apprenticeships; however, for purposes of E.O. 12866 analysis, adding these effects would constitute double-counting and they should instead be presented as an assessment of who, other than workers themselves, receives some portion of productivity benefits. Moreover, as noted earlier in this regulatory preamble, the report does not speak to the relative effects of RAPs and IRAPs.

Exhibit 2: Hospitals (NAICS 622)									
Small Business Size Standard: $8.0 million – $41.5 million									
	Number of Firms*	Number of Firms as Percent of Small Firms in Industry	Total Number of Employees*	Annual Receipts*	Average Receipts per Firm	First Year Cost Savings per Firm with 7% Discounting	First Year Cost Savings per Firm as Percent of Receipts	Annualized Cost Savings per Firm with 7% Discounting	Annualized Cost Savings per Firm as Percent of Receipts
Firms with receipts below $100,000	23	1.6%	0	$0	$0	$2,829	N/A	$3,027	N/A
Firms with receipts of $100,000 to $499,999	35	2.4%	145	$8,838,000	$252,514	$2,829	1.1%	$3,027	1.2%
Firms with receipts of $500,000 to $999,999	20	1.4%	136	$14,654,000	$732,700	$2,829	0.4%	$3,027	0.4%
Firms with receipts of $1,000,000 to $2,499,999	19	1.3%	515	$30,189,000	$1,588,895	$2,829	0.2%	$3,027	0.2%
Firms with receipts of $2,500,000 to $4,999,999	65	4.4%	3,616	$251,405,000	$3,867,769	$2,829	0.1%	$3,027	0.1%
Firms with receipts of $5,000,000 to $7,499,999	100	6.8%	7,135	$598,696,000	$5,986,960	$2,829	0.0%	$3,027	0.1%
Firms with receipts of $7,500,000 to $9,999,999	125	8.5%	12,010	$1,076,343,000	$8,610,744	$2,829	0.0%	$3,027	0.0%
Firms with receipts of $10,000,000 to $14,999,999	218	14.8%	28,209	$2,599,739,000	$11,925,408	$2,829	0.0%	$3,027	0.0%
Firms with receipts of $15,000,000 to $19,999,999	213	14.5%	36,660	$3,593,092,000	$16,868,977	$2,829	0.0%	$3,027	0.0%
Firms with receipts of $20,000,000 to $24,999,999	171	11.6%	36,287	$3,640,858,000	$21,291,567	$2,829	0.0%	$3,027	0.0%
Firms with receipts of $25,000,000 to $29,999,999	133	9.0%	31,171	$3,507,932,000	$26,375,429	$2,829	0.0%	$3,027	0.0%
Firms with receipts of $30,000,000 to $34,999,999	120	8.2%	31,175	$3,675,365,000	$30,628,042	$2,829	0.0%	$3,027	0.0%
Firms with receipts of $35,000,000 to $39,999,999	97	6.6%	30,001	$3,547,170,000	$36,568,763	$2,829	0.0%	$3,027	0.0%
Firms with receipts of $40,000,000 to $49,999,999	132	9.0%	48,369	$5,577,594,000	$42,254,500	$2,829	0.0%	$3,027	0.0%

* Source: U.S. Census Bureau, Statistics of U.S. Businesses, https://www.census.gov/data/tables/2017/econ/susb/2017-susb-annual.html.

Similarly, the proposed rule would result in cost savings for SREs. The cost savings would arise from SREs no longer needing to perform the activities listed in the E.O. 12866 preliminary economic analysis above: Notifying the Administrator of any major change to processes or programs; informing the Administrator of IRAP recognition, suspension, or derecognition; provision of data or information to the Administrator; provision of written attestation to the Administrator; disclosure of the credentials that apprentices will earn; quality control of IRAPs; submission of performance data to the Administrator; making publicly available IRAP performance data; and recordkeeping. The first-year cost savings per SRE is estimated at $13,099 at a discount rate of 7 percent. The annualized cost savings per SRE is estimated at $14,016 at a discount rate of 7 percent.

As of the date of this proposed rule, the Department has recognized 27 SREs. Only 5 of the 27 SREs have recognized IRAPs, and of those 5 SREs, only 1 so far has indicated that it has IRAP apprentices. This particular SRE is unlikely to be considered a small entity based on its annual revenue,[33] which exceeds the Small Business Administration's Small Business Size Standard of $16.5 million for professional organizations (North American Industry Classification System code 813920).[34]

Accordingly, the Department certifies that the proposed rule would not have a significant economic impact on a substantial number of small entities. Moreover, any economic impact experienced by IRAPs or SREs would be cost savings.

C. Paperwork Reduction Act

As explained in the ''Background'' section above, the Department is proposing to rescind subpart B, ''Standards Recognition Entities of Industry-Recognized Apprenticeship Programs,'' from title 29 CFR part 29, the regulatory framework for the Department's recognition of SREs and SREs' role in recognizing IRAPs.

As part of the implementation and rollout of the IRAP rule the Department developed and received OMB approval for two information collection requests (ICRs), an application form and a performance report. The first active ICR is entitled ''Industry-Recognized Apprenticeship Program Standards Recognition Entity Regulation and Application'' (OMB Control Number 1205–0536) and includes an annual approved burden of 141,819 responses and 285,310 hours. There is no additional cost burden. The second active ICR is entitled ''IRAP Program and Performance Report for Standards Recognition Entities'' (OMB Control Number 1205–0545) and includes an annual approved burden of 12,447 responses and 111,118 hours. There is no additional cost burden.

If a final rule rescinds subpart B, on the effective date of the regulation, the Department will withdraw its recognition of SREs and any SRE-recognized apprenticeship program would no longer be an IRAP as described in subpart B. The Department will no longer use the ''Industry-Recognized Apprenticeship Program Standards Recognition Entity Regulation and Application'' ICR and the ''IRAP Program and Performance Report for Standards Recognition Entities'' ICR.

Upon publication of a final rule, DOL will submit requests to discontinue both OMB Control Number 1205–0536 and OMB Control Number 1205–0545, eliminating all paperwork burden associated with the ICRs.

D. Executive Order 13132: Federalism

This proposed rule, if finalized, does not have federalism implications because it does not have substantial direct effects on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government. Accordingly, E.O. 13132, Federalism, requires no further agency action or analysis.

E. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1532, requires each Federal agency to prepare a written statement assessing the effects of any Federal mandate in a proposed agency rule that may result in $100 million or more in expenditures (adjusted annually for inflation) in any one year by State, local, and tribal governments, in the aggregate, or by the private sector.

[33] IRS Form 990 filing data available from the Internal Revenue Service, ''Tax Exempt Organization Search,'' *https://apps.irs.gov/app/eos.*

[34] U.S. Small Business Administration, ''Table of Small Business Size Standards'' (Aug. 19, 2019), available at *https://www.sba.gov/document/support--table-size-standards.*

This proposed rule, if finalized, does not exceed the $100-million expenditure in any one year when adjusted for inflation, and this rulemaking does not contain such a mandate. The requirements of title II of UMRA, therefore, do not apply, and the Department has not prepared a statement under the Act.

F. Executive Order 13175 (Indian Tribal Governments)

The Department has reviewed this proposed rule in accordance with E.O. 13175 and has determined that it does not have tribal implications. The proposed rule does not have substantial direct effects 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.

List of Subjects in 29 CFR Part 29

Apprenticeability criteria, Apprentice agreements and complaints, Apprenticeship programs, Program standards, Registration and deregistration, Sponsor eligibility, State apprenticeship agency recognition and derecognition.

For the reasons stated in the preamble, the Department proposes to amend 29 CFR part 29 as follows:

PART 29—LABOR STANDARDS FOR THE REGISTRATION OF APPRENTICESHIP PROGRAMS

■ 1. The authority citation for part 29 is revised to read as follows:

Authority: 9 U.S.C. 50; 40 U.S.C. 3145; 5 U.S.C. 301; 5 U.S.C. App. P. 534.

Subpart A—[Amended]

■ 2. Remove the designation of subpart A and the associated heading.
■ 3. Amend § 29.1 by:
■ a. Revising the section heading; and
■ b. In paragraph (b), removing the word ''subpart'' and adding the word ''part'' in its place.

The revision reads as follows:

§ 29.1 Purpose and scope.

* * * * *

§ 29.2 [Amended]

■ 4. Amend § 29.2 by:
■ a. In the introductory text, removing the word ''subpart'' and adding the word ''part'' in its place;
■ b. In the definitions of *Apprenticeship program* and *Registration agency,* removing the citation ''29 CFR part 29 subpart A, and part 30'' and adding the citation ''this part and 29 CFR part 30'' in its place; and
■ c. In the definition of *Technical assistance,* removing the word ''subpart'' and adding the word ''part'' in its place.

§ 29.13 [Amended]

■ 5. Amend § 29.13 by:
■ a. In paragraph (a)(1), removing the citation ''29 CFR part 29 subpart A, and part 30'' and adding the citation ''this part and 29 CFR part 30'' in its place;
■ b. In paragraph (b)(1), removing the citation ''29 CFR part 29 subpart A'' and adding ''this part'' in its place;
■ c. In paragraphs (c) and (e) introductory text, removing the word ''subpart'' and adding the word ''part'' in its place; and
■ d. In paragraph (e)(4), removing the citation ''part 29 subpart A'' and adding ''this part'' in its place.

§ 29.14 [Amended]

■ 6. Amend § 29.14 by:
■ a. In the introductory text, removing the citation ''part 29 subpart A, and part 30'' and adding the citation ''this part and 29 CFR part 30'' in its place; and
■ b. In paragraphs (e)(1) and (i), removing the word ''subpart'' and adding the word ''part'' in its place.

§ § 29.3, 29.6, 29.10, and 29.11 [Amended]

■ 7. In addition to the amendments set forth above, in 29 CFR part 29, remove the word ''subpart'' and add in its place the word ''part'' in the following places:
■ a. Section 29.3(b)(1), (g) introductory text, and (h);
■ b. Section 29.6(b)(2);
■ c. Section 29.10(a)(2); and
■ d. Section 29.11 introductory text.

Subpart B—[Removed]

■ 8. Remove subpart B, consisting of §§ 29.20 through 29.31.

Angela Hanks,

Acting Assistant Secretary for Employment and Training, Labor.

[FR Doc. 2021–24786 Filed 11–12–21; 8:45 am]

BILLING CODE 4510–FR–P

DEPARTMENT OF THE TREASURY

Office of Investment Security

31 CFR Parts 800 and 802

Regulations Pertaining to Certain Investments in the United States by Foreign Persons and Regulations Pertaining to Certain Transactions by Foreign Persons Involving Real Estate in the United States

AGENCY: Office of Investment Security, Department of the Treasury.

ACTION: Proposed rule.

SUMMARY: This proposed rule would modify the definitions of ''excepted foreign state'' and ''excepted real estate foreign state'' by extending by one year the effective date of one of two criteria set forth in the definitions in the regulations implementing certain provisions of Section 721 of the Defense Production Act of 1950, as amended.

DATES: Written comments must be received by December 15, 2021.

ADDRESSES: Written comments on this proposed rule may be submitted through one of two methods:

• *Electronic Submission:* Comments may be submitted electronically through the Federal government eRulemaking portal at *https://www.regulations.gov.* Electronic submission of comments allows the commenter maximum time to prepare and submit a comment, ensures timely receipt, and enables the Department of the Treasury (Treasury Department) to make the comments available to the public. Please note that comments submitted through *https://www.regulations.gov* will be public, and can be viewed by members of the public.

• *Mail:* Send to U.S. Department of the Treasury, Attention: Laura Black, Director of Investment Security Policy and International Relations, 1500 Pennsylvania Avenue NW, Washington, DC 20220.

Please submit comments only and include your name and company name (if any), and cite ''Proposed Regulations Pertaining to Certain Investments in the United States by Foreign Persons and Proposed Regulations Pertaining to Certain Transactions by Foreign Persons Involving Real Estate in the United States'' in all correspondence. In general, the Treasury Department will post all comments to *https://www.regulations.gov/* without change, including any business or personal information provided, such as names, addresses, email addresses, or telephone numbers. All comments received, including attachments and other supporting material, will be part of the public record and subject to public disclosure. You should only submit information that you wish to make publicly available.

FOR FURTHER INFORMATION CONTACT: Laura Black, Director of Investment Security Policy and International Relations, or Richard Rowe, Senior Policy Advisor, at U.S. Department of the Treasury, 1500 Pennsylvania Avenue NW, Washington, DC 20220; telephone: (202) 622–3425; email: *CFIUS.FIRRMA@treasury.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

A. The Statute

On August 13, 2018, the Foreign Investment Risk Review Modernization Act of 2018 (FIRRMA), Subtitle A of Title XVII of Public Law 115–232, 132 Stat. 2173, was enacted. FIRRMA amends section 721 (as amended, section 721) of the Defense Production Act of 1950, as amended, which delineates the authorities and jurisdiction of the Committee on Foreign Investment in the United States (CFIUS or the Committee). Executive Order 13456, 73 FR 4677 (Jan. 23, 2008), directs the Secretary of the Treasury to issue regulations under section 721. This proposed rule is being issued pursuant to that authority.

FIRRMA maintains the Committee's jurisdiction over any transaction which could result in foreign control of any U.S. business and broadens the authorities of the President and CFIUS under section 721 to review and take action to address national security concerns arising from certain noncontrolling investments and real estate transactions involving foreign persons. FIRRMA requires CFIUS to specify criteria to limit the application of FIRRMA's expanded jurisdiction over these noncontrolling investments and real estate transactions to certain categories of foreign persons.

B. Definitions of Excepted Foreign State and Excepted Real Estate Foreign State—Sections 800.218 and 802.214

On January 17, 2020, the Treasury Department published a final rule at 85 FR 3112 (Part 800 Rule) that amended 31 CFR part 800 to implement CFIUS's jurisdiction over certain non-controlling investments (which this rule describes as ''covered investments''), as well as certain other provisions of FIRRMA. The Treasury Department also published a final rule at 85 FR 3158 (Part 802 Rule) that established new regulations at part 802 of title 31 of the Code of Federal Regulations relating to CFIUS's authorities and the process and procedures to review transactions involving the purchase or lease by, or concession to, a foreign person of certain real estate in the United States. The Part 800 Rule and the Part 802 Rule each took effect on February 13, 2020, and each address FIRRMA's requirement to limit the application of FIRRMA's expanded jurisdiction.

The ''excepted foreign state'' definition in the Part 800 Rule operates together with other relevant terms to exclude from CFIUS's jurisdiction covered investments by certain foreign persons who meet certain criteria establishing sufficiently close ties to certain foreign states. Section 800.218 defines excepted foreign state by a two-criteria conjunctive test, with delayed effectiveness for the second criterion. The first criterion is that the Committee identify a foreign state as an eligible foreign state. The second criterion is that, by the end of the two-year delayed effectiveness period (*i.e.,* by February 13, 2022), the Committee make a determination under § 800.1001(a) for each eligible foreign state as to whether such foreign state ''has established and is effectively utilizing a robust process'' to analyze foreign investments for national security risks and to facilitate coordination with the United States on matters relating to investment security.

The ''excepted real estate foreign state'' definition in the Part 802 Rule operates together with other relevant terms to exclude from CFIUS's jurisdiction certain real estate transactions by certain foreign persons who meet certain criteria establishing sufficiently close ties to certain foreign states. The Part 802 Rule applies a two-criteria conjunctive test in the definition of excepted real estate foreign state that is analogous to the test in the Part 800 Rule, except that the second criterion is a determination under § 802.1001(a) that the foreign state must have ''made significant progress'' in establishing and effectively utilizing the robust process and coordination that is described in § 800.1001.

On January 17, 2020, the Committee identified Australia, Canada, and the United Kingdom of Great Britain and Northern Ireland as eligible excepted foreign states under the Part 800 Rule and as eligible excepted real estate foreign states under the Part 802 Rule. Thus, as of February 13, 2020, when the Part 800 Rule and the Part 802 Rule became effective, each of the three identified eligible foreign states was deemed to be an excepted foreign state and excepted real estate foreign state, without regard in each case to the second criterion, which is a determination under §§ 800.1001 and 802.1001. In order to remain an excepted foreign state and excepted real estate foreign state after February 12, 2022, each foreign state must remain eligible under §§ 800.218(a) and 802.214(a), respectively, and the Committee must make the determinations required under §§ 800.1001(a) and 802.1001(a), respectively, regarding the foreign state.

II. Proposed Change

The proposed rule would change the date in each of §§ 800.218 and 802.214 from February 13, 2022, to February 13, 2023. The proposed rule therefore would have the effect of extending the delayed effectiveness period for the second criterion in each of the Part 800 and Part 802 Rules without making any change to the two-criteria conjunctive test in either the definition of excepted foreign state or the definition of excepted real estate foreign state. The proposed rule would make no change to any country's status as an excepted foreign state or excepted real estate foreign state. Under the proposed rule, the Committee may make a determination under § 800.1001 or § 802.1001 for an eligible foreign state, including Australia, Canada, the United Kingdom of Great Britain and Northern Ireland and any other state that the Committee identifies as eligible, at any time before the revised February 13, 2023, date.

As stated in the preambles to the Part 800 Rule and the Part 802 Rule, the two-year period of delayed effectiveness for the second criterion in the definitions of excepted foreign state and excepted real estate foreign state was intended, in part, to provide the initial eligible foreign states time to ensure that their national security-based foreign investment review processes and bilateral cooperation with the United States on national security-based investment reviews meet the requirement under §§ 800.1001 and 802.1001. Extending the time period before which such requirements become applicable is desirable given certain ongoing changes to foreign investment review regimes.

III. Rulemaking Requirements

Executive Order 12866

These regulations are not subject to the general requirements of Executive Order 12866, which covers review of regulations by the Office of Information and Regulatory Affairs in the Office of Management and Budget (OMB), because they relate to a foreign affairs function of the United States, pursuant to section 3(d)(2) of that order. In addition, these regulations are not subject to review under section 6(b) of Executive Order 12866 pursuant to section 7(c) of the April 11, 2018, Memorandum of Agreement between the Treasury Department and OMB, which states that CFIUS regulations are not subject to OMB's standard centralized review process under Executive Order 12866.

Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.,* RFA) generally requires an agency to prepare a

regulatory flexibility analysis unless the agency certifies that the rule will not, once implemented, have a significant economic impact on a substantial number of small entities. The proposed rule would extend the delayed effectiveness period for the second criterion in each of the Part 800 and Part 802 Rules without making any change to the two-criteria conjunctive test in either the definition of excepted foreign state or excepted real estate foreign state. The proposed rule therefore would not change the circumstances of any investor. Both before and after the proposed rule's effectiveness, any investor with sufficiently close ties to an eligible foreign state may be excepted from certain aspects of CFIUS's jurisdiction, including if engaging in a transaction with a small business. Such exception would be expected to lessen the burden on any such small business. The proposed rule therefore would not impose any additional burden on potential filers, including small businesses. Considering the foregoing, the Secretary of the Treasury certifies, pursuant to 5 U.S.C. 605(b), that this proposed rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects

31 CFR Part 800

Foreign investments in the United States, Investments.

31 CFR Part 802

Investments, Real estate transactions in the United States.

For the reasons set forth in the preamble, the Treasury Department proposes to amend 31 CFR parts 800 and 802 as follows:

PART 800—REGULATIONS PERTAINING TO CERTAIN INVESTMENTS IN THE UNITED STATES BY FOREIGN PERSONS

■ 1. The authority citation for part 800 continues to read:

Authority: 50 U.S.C. 4565; E.O. 11858, as amended, 73 FR 4677.

Subpart B—Definitions

§ 800.218 [Amended]

■ 2. Amend § 800.218 introductory text by removing the year ''2022'' wherever it appears and adding in its place ''2023''.

PART 802—REGULATIONS PERTAINING TO CERTAIN TRANSACTIONS BY FOREIGN PERSONS INVOLVING REAL ESTATE IN THE UNITED STATES

■ 3. The authority citation for part 802 continues to read:

Authority: 50 U.S.C. 4565; E.O. 11858, as amended, 73 FR 4677.

Subpart B—Definitions

§ 802.214 [Amended]

■ 4. Amend § 802.214 introductory text by removing the year ''2022'' wherever it appears and adding in its place ''2023''.

Larry McDonald,

Acting Assistant Secretary for International Markets.

[FR Doc. 2021–24597 Filed 11–10–21; 4:15 pm]

BILLING CODE 4810–25–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2021–0808]

RIN 1625–AA08

Safety Zone; Tchefuncte River, Madisonville, LA; Correction

AGENCY: Coast Guard, Department of Homeland Security (DHS).

ACTION: Notice of proposed rulemaking; correction.

SUMMARY: The Coast Guard published a notice of proposed rulemaking (NPRM) in the **Federal Register** on November 10, 2021, titled ''Safety Zone; Tchefuncte River, Madisonville, LA.'' The document contained incorrect public comment period which closes after the date of the event. The comment period should have been 15 instead of 30 days.

DATES: The NPRM published on November 10, 2021, at 86 FR 62500, is corrected as of November 15, 2021.

ADDRESSES: You may submit comments identified by docket number USCG–2021–0808 using the Federal Decision Making Portal at *https://www.regulations.gov.* See the ''Public Participation and Request for Comments'' portion of the **SUPPLEMENTARY INFORMATION** section in the NPRM published on November 10, 2021, at 86 FR 62500, for further instructions on submitting comments.

FOR FURTHER INFORMATION CONTACT: If you have questions about this document, call or email Lieutenant Commander William A. Stewart, Waterways Management Division Chief, U.S. Coast Guard; telephone 504–365–2246, email *William.A.Stewart@uscg.mil.*

SUPPLEMENTARY INFORMATION: The document published on November 10, 2021, at 86 FR 62500, contains an incorrect public comment period end date which closes on December 10, 2021, after the date of the event. The comment period should have been 15 instead of 30 days with an end date of November 22, 2021.

Correction

In the **Federal Register** of November 10, 2021, in FR Doc. 2021–24588, beginning on page 62500, the following corrections are made:

1. On page 62500, in the third column, in the **DATES** section, remove the text, ''December 10, 2021'' and add in its place the text ''November 22, 2021''.

Dated: November 10, 2021.

M.T. Cunningham,

Chief, Office of Regulations and Administrative Law.

[FR Doc. 2021–24946 Filed 11–12–21; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

[Docket No. FWS–R4–ES–2018–0035; FXES11130400000–212–FF04E00000]

RIN 1018–BB98

Endangered and Threatened Wildlife and Plants; Replacement of the Regulations for the Nonessential Experimental Population of Red Wolves in Northeastern North Carolina

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Proposed rule; withdrawal.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), withdraw the proposed rule to replace the existing regulations governing the North Carolina nonessential experimental population designation of the red wolf (*Canis rufus*) under section 10(j) of the Endangered Species Act (Act), as amended. Based on recent court decisions involving the North Carolina nonessential experimental population designation of the red wolf (NC NEP), having considered the public comments submitted in response to the proposed

rule, and upon further consideration of the proposal, we have determined that withdrawing the proposed rule is the best course of action at this time. The NC NEP will be managed under the provisions of the existing regulations and as informed by relevant court orders.

DATES: The U.S. Fish and Wildlife Service is withdrawing the proposed rule published on June 28, 2018 (83 FR 30382), as of November 15, 2021.

ADDRESSES: This withdrawal of the proposed rule and supporting documents are available on the internet at *https://www.regulations.gov* at Docket No. FWS–R4–ES–2018–0035.

FOR FURTHER INFORMATION CONTACT: Pete Benjamin, Field Supervisor, U.S. Fish and Wildlife Service, Raleigh Ecological Services Field Office, 551F Pylon Drive, Raleigh, NC 27606; telephone 919–856–4520; or facsimile 919–856–4556. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Relay Service at 1–800–877–8339.

SUPPLEMENTARY INFORMATION:

Previous Federal Actions

Please refer to our June 28, 2018, proposed rule (83 FR 30382) for a detailed description of previous Federal actions concerning the red wolf.

Service Actions

On April 24, 2018, the Service completed a species status assessment (SSA) and 5-year status review for the red wolf. The SSA represents a compilation of the best scientific and commercial data available concerning the status of the species, including the impacts of past, present, and future factors (both negative and beneficial) affecting the red wolf. The SSA can be found on the Southeast Region website at *https://www.fws.gov/southeast/wildlife/mammals/red-wolf/* and at *https://www.regulations.gov* under Docket No. FWS–R4–ES–2018–0035. In the 5-year status review, we determined that the species continues to meet the definition of an endangered species, as defined under section 3 of the Act (16 U.S.C. 1531 *et seq.*), and did not recommend a change in status. The 5-year review is available at *https://ecos.fws.gov/docs/five_year_review/doc5714.pdf.*

On June 28, 2018, we published in the **Federal Register** (83 FR 30382) a proposed rule to replace the existing regulations governing the NC NEP, which were codified in 1995 (see 60 FR 18940; April 13, 1995), in title 50 of the Code of Federal Regulations (CFR) at § 17.84(c) (50 CFR 17.84(c)). In the June 28, 2018, proposed rule, we made available a draft environmental assessment for the proposed regulations, and we opened a 30-day comment period, which ended July 30, 2018. On July 10, 2018, we held a public information session and public hearing on the proposed rule and draft environmental assessment. On August 13, 2018, we published in the **Federal Register** (83 FR 39979) a document reopening the proposed rule's comment period for another 15 days to allow the public an additional opportunity to review and comment on the proposed rule and draft environmental assessment.

Legal Actions

On November 12, 2015, Southern Environmental Law Center, on behalf of Red Wolf Coalition, Defenders of Wildlife, and the Animal Welfare Institute (plaintiffs), filed a complaint challenging the Service's management of the NC NEP, alleging, in part, that we violated section 9 of the Act by authorizing take of red wolves by private landowners without satisfying the requirements of 50 CFR 17.84(c)(4)(v). On September 28, 2016, the U.S. District Court for the Eastern District of North Carolina (Court) issued a preliminary injunction prohibiting the take of red wolves either directly or by landowner authorization, pursuant to 50 CFR 17.84(c)(4)(v) and (c)(10), without first demonstrating that the red wolf is a threat to human safety or the safety of livestock (see *Red Wolf Coal* v. *United States Fish & Wildlife Serv.,* 210 F. Supp. 3d 796 (E.D.N.C. 2016)). On November 4, 2018, the Court permanently enjoined the Service from taking red wolves either directly or by landowner authorization, pursuant to 50 CFR 17.84(c)(4)(v) and (c)(10) without first demonstrating that such red wolves are a threat to human safety or the safety of livestock or pets (see *Red Wolf Coal* v. *United States Fish & Wildlife Serv.,* 346 F. Supp. 3d 802 (E.D.N.C. 2018)). At that time, we announced that we would evaluate the implications of the Court's decision on the June 28, 2018, proposed rule.

On November 16, 2020, plaintiffs filed a complaint against the Service alleging violations of the Act and of the Administrative Procedure Act (APA; 5 U.S.C. 551 *et seq.*) in connection with management of the NC NEP. Specifically, they alleged that the Service interpreted its existing regulations at 50 CFR 17.84(c) as prohibiting additional releases of captive red wolves into the NC NEP and prohibiting implementation of the Red Wolf Adaptive Management Work Plan (RWAMWP) and that this interpretation constituted a new policy that was adopted in contravention of the Act and the APA. Shortly after filing the suit, plaintiffs filed a motion for preliminary injunction to require the Service to release red wolves from captivity and reinstate the use of the RWAMWP. On January 22, 2021, the Court granted plaintiffs' motion for preliminary injunction determining that plaintiffs were likely to succeed on the merits of their claims that the Service adopted a policy preventing the Service from releasing captive red wolves into the NC NEP in violation of the Act and the APA. The Court's injunction barred the Service from effecting this policy and ordered the Service to develop a plan to release red wolves into the NC NEP and submit the plan to the Court by March 1, 2021 (see *Red Wolf Coalition* v. *U.S. Fish and Wildlife Service* (No. 2:20–CV–75–BO) (January 22, 2021)). On March 1, 2021, the Service filed with the Court our plan to release red wolves into the NC NEP. On April 14, 2021, the Court issued an order directing the Service to immediately implement that release plan.

Background

On April 13, 1995, we published in the **Federal Register** (60 FR 18940) a final rule amending the regulations at 50 CFR 17.84(c) for the nonessential experimental populations of red wolves in North Carolina and Tennessee. Since that time, the NC NEP has been managed under the regulations set forth in the April 13, 1995, final rule at 50 CFR 17.84(c). On June 28, 2018, we published in the **Federal Register** (83 FR 30382) a proposed rule to replace those existing regulations. The purpose of the proposed rule was to incorporate the most recent science and lessons learned related to the management of red wolves to further the conservation of the species. We proposed to establish a more manageable wild population that would allow for more resources to support the captive population component of the red wolf program (which is the genetic fail safe for the species), serve the future needs of new reintroduction efforts, retain the influences of natural selection on the species, eliminate regulatory burden on private landowners, and provide a population for continued scientific research on wild red wolf behavior and population management.

The June 28, 2018, rule proposed to:

- Establish an NC NEP management area to include Alligator River National Wildlife Refuge (NWR) and the Dare County Bombing Range. A small group (*i.e.,* one or two packs likely consisting

of fewer than 15 animals) of red wolves would be maintained in the NC NEP management area and actively managed under the RWAMWP.

• Specify that the primary role of the NC NEP would be to provide a source of red wolves that are raised in, and adapted to, natural conditions for the purpose of facilitating future reintroductions.

• Not prohibit take of red wolves on private lands and non-Federal public lands outside of the NC NEP management area.

Withdrawal of Proposed Rule

During the two comment periods on the June 28, 2018, proposed rule, we received more than 16,000 public comments. Of those, more than 99 percent of the comments opposed the proposed rule and recommended greater conservation efforts for red wolves in the NC NEP. In general, commenters were concerned about the reduction in the size of the NEP area and lack of take prohibitions on private and non-Federal lands outside the NC NEP management area; many commenters asserted that the proposed rule did not further the conservation of the red wolf. Additionally, many commenters recommended that the rule include measures for improving working relationships with private landowners and other stakeholders, and foster increased tolerance of red wolves on private lands.

After fully considering the recent court decisions involving the NC NEP discussed above under *Legal Actions* and concerns raised in the comments we received in response to the June 28, 2018, proposed rule, we are withdrawing the June 28, 2018, proposed rule. We will manage the NC NEP under the existing regulations at 50 CFR 17.84(c), as informed by relevant court orders, which include authority to release captive red wolves and conduct adaptive management. The NC NEP will continue to encompass the five counties of the Albemarle Peninsula in North Carolina (Beaufort, Dare, Hyde, Tyrrell, and Washington Counties). Furthermore, the Service currently has a permit from the North Carolina Wildlife Resources Commission (which regulates take of coyotes) authorizing the Service to conduct coyote sterilization on Federal lands and non-Federal lands with the written consent of the landowner within the five-county NC NEP.

Authorized take will be limited to protection of oneself or others from potential harm, protection of livestock or pets in immediate danger, and unintentional take. Otherwise, take prohibitions under section 9 of the Act will be enforced. While we remain concerned that the existing regulations at 50 CFR 17.84(c) may not provide some private landowners and stakeholders with the management flexibility sufficient to improve tolerance of red wolves, we continue to work with stakeholders to identify ways to foster more effective coexistence between people and wolves. For example, the Service has implemented a new project under its Partners for Fish and Wildlife Program, Prey for the Pack, which is intended to improve these relationships and create a more supportive environment for conservation of red wolves. Through this program, the Service works with willing private landowners within the NC NEP to provide funding and technical assistance to restore and enhance habitat on private lands to benefit red wolf prey species (*e.g.,* white-tailed deer, rabbits) in exchange for landowner willingness to tolerate red wolf use of their property and to provide the Service access to conduct red wolf management activities. We will continue to work with our partners and stakeholders to establish the support necessary for red wolf conservation.

Authors

The primary authors of this rule are the staff members of the Service's South Atlantic-Gulf Interior Region.

Authority

The authority for this action is the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*).

Martha Williams,

Principal Deputy Director, Exercising the Delegated Authority of the Director, U.S. Fish and Wildlife Service.

[FR Doc. 2021–24809 Filed 11–12–21; 8:45 am]

BILLING CODE 4333–15–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 665

RIN 0648–BK66

Pacific Island Fisheries; Amendment 6 to the Fishery Ecosystem Plan for the Mariana Archipelago; Rebuilding Plan for Guam Bottomfish

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of availability of fishery ecosystem plan amendment; request for comments.

SUMMARY: NMFS announces that the Western Pacific Fishery Management Council (Council) proposes to amend the Fishery Ecosystem Plan for the Mariana Archipelago (FEP). If approved, Amendment 6 would establish a rebuilding plan for the Guam bottomfish stock complex. The Council recommended Amendment 6 to rebuild the Guam bottomfish stock, which is overfished.

DATES: NMFS must receive comments on Amendment 6 by January 14, 2022.

ADDRESSES: You may submit comments on this document, identified by NOAA–NMFS–2021–0104, by either of the following methods:

• *Electronic Submission:* Submit all electronic public comments via the Federal e-Rulemaking Portal. Go to *http://www.regulations.gov* and enter NOAA–NMFS–2021–0104 in the Search box, click the ''Comment Now!'' icon, complete the required fields, and enter or attach your comments.

• *Mail:* Send written comments to Michael D. Tosatto, Regional Administrator, NMFS Pacific Islands Region (PIR), 1845 Wasp Blvd., Bldg. 176, Honolulu, HI 96818.

Instructions: NMFS may not consider comments sent by any other method, to any other address or individual, or received after the end of the comment period. All comments received are a part of the public record, and NMFS will generally post them for public viewing on *www.regulations.gov* without change. All personal identifying information (*e.g.,* name, address, etc.), confidential business information, or otherwise sensitive information submitted voluntarily by the sender will be publicly accessible. NMFS will accept anonymous comments (enter ''N/A'' in the required fields if you wish to remain anonymous).

Amendment 6 includes a draft environmental assessment (EA) that analyzes the potential impacts of the proposed action and alternatives considered. Copies of Amendment 6, including the draft EA and Regulatory Impact Review (RIR), and other supporting documents are available at *www.regulations.gov* or the Council, 1164 Bishop St., Suite 1400, Honolulu, HI 96813, tel 808–522–8220, fax 808–522–8226, *www.wpcouncil.org.*

FOR FURTHER INFORMATION CONTACT: Kate Taylor, Sustainable Fisheries, NMFS PIR, 808–725–5182.

SUPPLEMENTARY INFORMATION: NMFS and the Council manage the Guam

bottomfish fishery under the FEP and implementing regulations. The Guam fishery harvests 11 species of emperors, snappers, groupers, and jacks. There are more than 300 participants in the fishery. Most (73.6 percent) of the bottomfish habitat is in territorial waters, with the rest in Federal waters around offshore banks to the northeast and southwest of Guam. Fishing is mostly from vessels less than 25 ft (7.6 m) in length close to shore, targeting shallow-water species for recreational, subsistence, and small-scale commercial purposes. A few larger vessels make trips to offshore banks to harvest deepwater species primarily for commercial purposes.

Since 2001, the fishery landed between 11,711 (5,312 kg) and 54,062 lb (24,522 kg) annually. The most recent 3 year average (2018–2020) Guam bottomfish catch (from both Federal and territorial waters) was 27,306 lb (12,386 kg), and the fishery landed 18,933 lb (8,588 kg) in 2020. Although bottomfish have accounted for only 10–15 percent of Guam's boat-based fish harvest, bottomfish hold fundamental dietary and cultural importance for the people of Guam. Federal waters around Guam remain important for the harvest of deepwater snappers at offshore banks to provide locally sourced bottomfish.

On February 10, 2020, NMFS notified the Council that the Guam bottomfish stock complex was overfished, but not subject to overfishing (85 FR 26940, May 6, 2020). Consistent with Section 304(e) of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) and implementing regulations at 50 CFR 600.310(j), the Council must prepare, and NMFS must implement a rebuilding plan within two years of the notification. If approved, Amendment 6 would implement a rebuilding plan for the Guam bottomfish stock complex that consists of an annual catch limit (ACL) and two accountability measures (AM). We would set the ACL 31,000 lb (14,061 kg) starting in 2022, and catches from both territorial and Federal waters around Guam would count toward the ACL. The fishing year is the calendar year.

As an in-season AM, if NMFS projects that the fishery will reach the ACL in any year, then we would close the fishery in Federal waters for the remainder of that year. As an additional AM, if subsequent analyses indicate that the fishery exceeded the ACL during a year, we would close the fishery in Federal waters until NMFS and the Territory of Guam implement a coordinated management regime to ensure that the catch in both Federal and territorial waters is maintained at levels that allow the stock to rebuild. The rebuilding plan would remain in place until NMFS determines that the stock complex is rebuilt, which is expected to take eight years. NMFS and the Council would review the rebuilding plan every two years and amend it, as necessary.

NMFS must receive comments on Amendment 6 by January 14, 2022 for consideration in the decision to approve, partially approve, or disapprove the amendment. Concurrent with NMFS's review of the amendment under the Magnuson-Stevens Act procedures, NMFS expects to publish in the **Federal Register** and request public comment on a proposed rule to implement the draft measures described in Amendment 6.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: November 9, 2021.

Ngagne Jafnar Gueye,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2021–24837 Filed 11–9–21; 4:15 pm]

BILLING CODE 3510–22–P

Notices

Federal Register
Vol. 86, No. 217
Monday, November 15, 2021

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

[Doc. No. AMS–FGIS–21–0084]

Grain Inspection Advisory Committee Meeting

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Notice of Federal Advisory Committee meeting.

SUMMARY: Pursuant to the Federal Advisory Committee Act, this action constitutes notice of the upcoming meeting of the Grain Inspection Advisory Committee (Advisory Committee). The Advisory Committee meets no less than once annually to advise the Secretary on the programs and services delivered by the Agricultural Marketing Service (AMS) under the U.S. Grain Standards Act. Recommendations by the Advisory Committee help AMS meet the needs of its customers, who operate in a dynamic and changing marketplace.

DATES: December 15, 2021, 11:00 a.m. to 5:00 p.m. Eastern & December 16, 2021, 11:00 a.m. to 5:00 p.m. Eastern.

Location: Virtual; Meeting information can be found at: *https://www.ams.usda.gov/about-ams/facas-advisory-councils/giac.*

FOR FURTHER INFORMATION CONTACT: Kendra Kline by phone at (202) 690–2410 or by email at *Kendra.C.Kline@usda.gov.*

SUPPLEMENTARY INFORMATION: The purpose of the Advisory Committee is to provide advice to AMS with respect to the implementation of the U.S. Grain Standards Act (7 U.S.C. 71–87k). Information about the Advisory Committee is available on the AMS website at *https://www.ams.usda.gov/about-ams/facas-advisory-councils/giac.*

The agenda for the upcoming meeting will include general program updates; a presentation regarding AMS agricultural transportation data analyses; and discussions about average inspections flexibilities, the FGIS Inspection Technology Review Process, and the development of pre-approved reconditioning procedures for actionable lots identified under the Federal Grain Inspection Service/Food and Drug Administration memorandum of understanding.

Public participation will be limited to written statements and interested parties who have registered to present comments orally to the Advisory Committee. If interested in submitting a written statement or presenting comments orally, please contact Kendra Kline at the telephone number or email address listed above. Opportunities to provide oral comments will be given in the order the requests to speak are received. The meeting will be open to the public.

Persons with disabilities who require alternative means of communication of program information or related accommodations should contact Kendra Kline at the telephone number or email listed above.

Dated: November 8, 2021.

Cikena Reid,

USDA Committee Management Officer.

[FR Doc. 2021–24724 Filed 11–12–21; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF AGRICULTURE

Submission for OMB Review; Comment Request

The Department of Agriculture has submitted the following information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. Comments are requested regarding whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; ways to enhance the quality, utility and clarity of the information to be collected; and ways to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

Comments regarding this information collection received by December 15, 2021 will be considered. Written comments and recommendations for the proposed information collection should be submitted within 30 days of the publication of this notice on the following website *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function

An agency may not conduct or sponsor a collection of information unless the collection of information displays a currently valid OMB control number and the agency informs potential persons who are to respond to the collection of information that such persons are not required to respond to the collection of information unless it displays a currently valid OMB control number.

Food Safety and Inspection Service

Title: Petitions for Rulemaking.

OMB Control Number: 0583–0136.

Summary of Collection: The Food Safety and Inspection Service (FSIS) has been delegated the authority to exercise the functions of the Secretary as provided in the Federal Meat Inspection Act (FMIA) (21 U.S.C. 601 *et seq.*), the Poultry Products Inspection Act (PPIA) (21 U.S.C. 451 *et seq.*), and the Egg Product Inspection Act (EPIA) (21 U.S.C. 1031 *et seq.*). These statutes mandate that FSIS protect the public by ensuring that meat and poultry products are safe, wholesome, unadulterated, and properly labeled and packaged. The Administrative Procedures Act requires that Federal agencies give interested persons the right to petition for issuance, amendment, or repeal of a rule (5 U.S.C. 553 (e)). FSIS has regulations (9 CFR 392) governing petitions to the Agency to issue, amend, or repeal its regulations.

Need and Use of the Information: FSIS will use the information associated with petitions to assess the merits of the petition and to determine whether to issue, amend, or repeal its regulations. If the information is not collected or collected less frequently, it would reduce the effectiveness of the meat, poultry, and egg products inspection program.

Description of Respondents: Business or other for-profit.

Number of Respondents: 10.

Frequency of Responses: Reporting: On occasion.

Total Burden Hours: 400.

Dated: November 9, 2021.

Ruth Brown,

Departmental Information Collection Clearance Officer.

[FR Doc. 2021–24884 Filed 11–12–21; 8:45 am]

BILLING CODE 3410–DM–P

DEPARTMENT OF AGRICULTURE

Submission for OMB Review; Comment Request

November 8, 2021,

The Department of Agriculture has submitted the following information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. Comments are requested regarding: Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; ways to enhance the quality, utility and clarity of the information to be collected; and ways to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

Comments regarding this information collection received by December 15, 2021 will be considered. Written comments and recommendations for the proposed information collection should be submitted within 30 days of the publication of this notice on the following website *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

An agency may not conduct or sponsor a collection of information unless the collection of information displays a currently valid OMB control number and the agency informs potential persons who are to respond to the collection of information that such persons are not required to respond to the collection of information unless it displays a currently valid OMB control number.

Rural Business-Cooperative Service

Title: 7 CFR 1951–R, Rural Development Loan Servicing.

OMB Control Number: 0570–0015.

Summary of Collection: The Rural Development (RD) Loan Servicing was legislated in 1985 under Section 1323 of the Food and Security Act of 1985. This action is needed to implement the provision of Section 407 of the Health and Human Services Act of 1986, which amended Section 1323 of the Food and Security Act of 1985. Subpart R of 7 CFR part 1951 contains regulations for servicing and liquidating loans made by Rural Development under the Intermediary Relending Program (IRP) and the Rural Microentrepreneur Assistance Program (RMAP) to eligible intermediaries and applies to ultimate recipients and other involved parties.

Need and Use of the Information: Rural Development has determined that the financial reporting requirements are necessary to provide the Agency with current information to monitor the program, to make various reporting requirements to Congress, and for program innovation and expansion under the Government's Performance Review.

Servicing of the IRP is administered by RBCS in Washington, DC, which will be the primary user of the information collected, which is vital to RBS for prudent loan servicing, credit decisions, and reasonable program monitoring.

Description of Respondents: Non-profit corporations, public agencies, Tribal councils, and cooperatives.

Number of Respondents: 475.

Frequency of Responses: Reporting: On occasion; Quarterly; Semi-annually; Annually.

Total Burden Hours: 11,878.

Levi S. Harrell,

Departmental Information Collection Clearance Officer.

[FR Doc. 2021–24741 Filed 11–12–21; 8:45 am]

BILLING CODE 3410–XY–P

DEPARTMENT OF COMMERCE

Foreign-Trade Zones Board

[B–54–2021]

Foreign-Trade Zone (FTZ) 75—Phoenix, Arizona, Authorization of Production Activity, Nikola Corporation (Electric Road Tractors and Motor Vehicles), Coolidge, Arizona

On July 12, 2021, Nikola Corporation (Nikola) submitted a notification of proposed production activity to the FTZ Board for its facility within Subzone 75M, in Coolidge, Arizona.

The notification was processed in accordance with the regulations of the FTZ Board (15 CFR part 400), including notice in the **Federal Register** inviting public comment (86 FR 38008, July 19, 2021). On November 9, 2021, the applicant was notified of the FTZ Board's decision that no further review of the proposed activity is warranted at this time. The FTZ Board authorized the production activity described in the notification, subject to the FTZ Act and the Board's regulations, including Section 400.14. The following must be admitted in privileged foreign status (19 CFR 146.41): Tufted carpet; canvas rain guards; motor vehicle seats; upholstered metal frame seats; and, seatbacks, cushions, frames, and seating.

Dated: November 9, 2021.

Elizabeth Whiteman,

Acting Executive Secretary.

[FR Doc. 2021–24856 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

Foreign-Trade Zones Board

[B–72–2021]

Foreign-Trade Zone (FTZ) 93—Raleigh-Durham, North Carolina, Notification of Proposed Production Activity, BrightView Technologies, Inc. (Plastic Film), Durham, North Carolina

The Triangle J Council of Governments, grantee of FTZ 93, submitted a notification of proposed production activity to the FTZ Board (the Board) on behalf of BrightView Technologies, Inc. (BVT), located in Durham, North Carolina under FTZ 93. The notification conforming to the requirements of the Board's regulations (15 CFR 400.22) was received on November 5, 2021.

Pursuant to 15 CFR 400.14(b), FTZ production activity would be limited to the specific foreign-status material/component and specific finished product described in the submitted notification (summarized below) and subsequently authorized by the Board. The benefits that may stem from conducting production activity under FTZ procedures are explained in the background section of the Board's website—accessible via *www.trade.gov/ftz.*

The proposed finished product is plastic film with microstructures (duty rate 5.3%).

The proposed foreign-status material/component is polycarbonate film (duty rate 5.8%). The request indicates that the material/component is subject to

duties under Section 301 of the Trade Act of 1974 (Section 301), depending on the country of origin. The applicable Section 301 decisions require subject merchandise to be admitted to FTZs in privileged foreign status (19 CFR 146.41).

Public comment is invited from interested parties. Submissions shall be addressed to the Board's Executive Secretary and sent to: *ftz@trade.gov.* The closing period for their receipt is December 27, 2021.

A copy of the notification will be available for public inspection in the ''Online FTZ Information System'' section of the Board's website.

For further information, contact Elizabeth Whiteman at *Elizabeth.Whiteman@trade.gov.*

Dated: November 8, 2021.

Elizabeth Whiteman,

Acting Executive Secretary.

[FR Doc. 2021–24819 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Order Denying Export Privileges; In the Matter of: Christopher Daniel Stines, Inmate Number: 18330–104, Big Spring, Correctional Institution, 2001 Rickabaugh Drive, Big Spring, TX 79720

On March 2, 2020, in the U.S. District Court for the Southern District of Florida, Christopher Daniel Stines (''Stines'') was convicted of violating 18 U.S.C. 554(a). Specifically, Stines was convicted of fraudulently and knowingly attempting to export and send from the United States to Haiti, firearm parts, to include: Eight (8) AR–15 triggers, five (5) AR–15 selector switches, three (3) AR–15 hammers, two (2) AR–15 disconnectors, three (3) AR–15 hammer and trigger pins, and two (2) AR–15 trigger guards. Stines was sentenced to 46 months in prison, two years of supervised released and a $100 assessment.

Pursuant to Section 1760(e) of the Export Control Reform Act (''ECRA''),[1] the export privileges of any person who has been convicted of certain offenses, including, but not limited to, 18 U.S.C. 554, may be denied for a period of up to ten (10) years from the date of his/her conviction. 50 U.S.C. 4819(e) (Prior Convictions). In addition, any Bureau of Industry and Security (BIS) licenses or other authorizations issued under ECRA, in which the person had an interest at the time of the conviction, may be revoked. *Id.*

BIS received notice of Stines's conviction for violating 18 U.S.C. 554, and has provided notice and opportunity for Stines to make a written submission to BIS, as provided in Section 766.25 of the Export Administration Regulations (''EAR'' or the ''Regulations''). 15 CFR 766.25.[2] BIS has not received a written submission from Stines.

Based upon my review of the record and consultations with BIS's Office of Exporter Services, including its Director, and the facts available to BIS, I have decided to deny Stines's export privileges under the Regulations for a period of 10 years from the date of Stines's conviction. The Office of Exporter Services has also decided to revoke any BIS-issued licenses in which Stines had an interest at the time of his conviction.[3]

Accordingly, it is hereby *ordered*:

First, from the date of this Order until March 2, 2030, Christopher Daniel Stines, with a last known address of Inmate Number: 18330–104, Big Spring, Correctional Institution, 2001 Rickabaugh Drive, Big Spring, TX 79720, and when acting for or on his behalf, his successors, assigns, employees, agents or representatives (''the Denied Person''), may not directly or indirectly participate in any way in any transaction involving any commodity, software or technology (hereinafter collectively referred to as ''item'') exported or to be exported from the United States that is subject to the Regulations, including, but not limited to:

A. Applying for, obtaining, or using any license, license exception, or export control document;

B. Carrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or engaging in any other activity subject to the Regulations; or

C. Benefitting in any way from any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or from any other activity subject to the Regulations.

Second, no person may, directly or indirectly, do any of the following:

A. Export, reexport, or transfer (in-country) to or on behalf of the Denied Person any item subject to the Regulations;

B. Take any action that facilitates the acquisition or attempted acquisition by the Denied Person of the ownership, possession, or control of any item subject to the Regulations that has been or will be exported from the United States, including financing or other support activities related to a transaction whereby the Denied Person acquires or attempts to acquire such ownership, possession or control;

C. Take any action to acquire from or to facilitate the acquisition or attempted acquisition from the Denied Person of any item subject to the Regulations that has been exported from the United States;

D. Obtain from the Denied Person in the United States any item subject to the Regulations with knowledge or reason to know that the item will be, or is intended to be, exported from the United States; or

E. Engage in any transaction to service any item subject to the Regulations that has been or will be exported from the United States and which is owned, possessed or controlled by the Denied Person, or service any item, of whatever origin, that is owned, possessed or controlled by the Denied Person if such service involves the use of any item subject to the Regulations that has been or will be exported from the United States. For purposes of this paragraph, servicing means installation, maintenance, repair, modification or testing.

Third, pursuant to section 1760(e) of the Export Control Reform Act (50 U.S.C. 4819(e)) and sections 766.23 and 766.25 of the Regulations, any other person, firm, corporation, or business organization related to Stines by ownership, control, position of responsibility, affiliation, or other connection in the conduct of trade or business may also be made subject to the provisions of this Order in order to prevent evasion of this Order.

Fourth, in accordance with part 756 of the Regulations, Stines may file an appeal of this Order with the Under Secretary of Commerce for Industry and Security. The appeal must be filed within 45 days from the date of this Order and must comply with the provisions of part 756 of the Regulations.

[1] ECRA was enacted as part of the John S. McCain National Defense Authorization Act for Fiscal Year 2019, and as amended is codified at 50 U.S.C. 4801–4852. Stines's conviction post-dates ECRA's enactment on August 13, 2018.

[2] The Regulations are currently codified in the Code of Federal Regulations at 15 CFR parts 730–774 (2021).

[3] The Director, Office of Export Enforcement, is now the authorizing official for issuance of denial orders, pursuant to recent amendments to the Regulations (85 FR 73411, November 18, 2020).

Fifth, a copy of this Order shall be delivered to Stines and shall be published in the **Federal Register**.

Sixth, this Order is effective immediately and shall remain in effect until March 2, 2030.

John Sonderman,

Director, Office of Export Enforcement.

[FR Doc. 2021–24804 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–DT–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Order Denying Export Privileges

In the Matter of: Hersel Lincoln McKenzie, Jr.; 2624 ½ S. Cochran Avenue, Los Angeles, CA 90016.

On January 8, 2020, in the U.S. District Court for the Southern District of Texas, Hersel Lincoln McKenzie, Jr. (''McKenzie'') was convicted of violating 18 U.S.C. 554(a). Specifically, McKenzie was convicted of knowingly and fraudulently attempting to export and exporting from the United States to Mexico, certain merchandise, articles and objects, namely 7.62 × 39 mm ammunition, in violation of 18 U.S.C. 554. As a result of his conviction, the Court sentenced McKenzie to 12 months and one day in prison, and a $100 assessment.

Pursuant to Section 1760(e) of the Export Control Reform Act (''ECRA''),[1] the export privileges of any person who has been convicted of certain offenses, including, but not limited to, 18 U.S.C. 554, may be denied for a period of up to ten (10) years from the date of his/her conviction. 50 U.S.C. 4819(e) (Prior Convictions). In addition, any Bureau of Industry and Security (''BIS'') licenses or other authorizations issued under ECRA, in which the person had an interest at the time of the conviction, may be revoked. *Id.*

BIS received notice of McKenzie's conviction for violating 18 U.S.C. 554, and has provided notice and opportunity for McKenzie to make a written submission to BIS, as provided in Section 766.25 of the Export Administration Regulations (''EAR'' or the ''Regulations''). 15 CFR 766.25.[2] BIS has received and considered a written submission from McKenzie.

Based upon my review of the record, including McKenzie's submission, and consultations with BIS's Office of Exporter Services, including its Director, and the facts available to BIS, I have decided to deny McKenzie's export privileges under the Regulations for a period of five years from the date of McKenzie's conviction. The Office of Exporter Services has also decided to revoke any BIS-issued licenses in which McKenzie had an interest at the time of his conviction.[3]

Accordingly, it is hereby *ordered:*

First, from the date of this Order until January 8, 2025, Hersel Lincoln McKenzie, Jr., with a last known address of 2624½ S. Cochran Avenue, Los Angeles, CA 90016, and when acting for or on his behalf, his successors, assigns, employees, agents or representatives (''the Denied Person''), may not directly or indirectly participate in any way in any transaction involving any commodity, software or technology (hereinafter collectively referred to as ''item'') exported or to be exported from the United States that is subject to the Regulations, including, but not limited to:

A. Applying for, obtaining, or using any license, license exception, or export control document;

B. Carrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or engaging in any other activity subject to the Regulations; or

C. Benefitting in any way from any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or from any other activity subject to the Regulations.

Second, no person may, directly or indirectly, do any of the following:

A. Export, reexport, or transfer (in-country) to or on behalf of the Denied Person any item subject to the Regulations;

B. Take any action that facilitates the acquisition or attempted acquisition by the Denied Person of the ownership, possession, or control of any item subject to the Regulations that has been or will be exported from the United States, including financing or other support activities related to a transaction whereby the Denied Person acquires or attempts to acquire such ownership, possession or control;

C. Take any action to acquire from or to facilitate the acquisition or attempted acquisition from the Denied Person of any item subject to the Regulations that has been exported from the United States;

D. Obtain from the Denied Person in the United States any item subject to the Regulations with knowledge or reason to know that the item will be, or is intended to be, exported from the United States; or

E. Engage in any transaction to service any item subject to the Regulations that has been or will be exported from the United States and which is owned, possessed or controlled by the Denied Person, or service any item, of whatever origin, that is owned, possessed or controlled by the Denied Person if such service involves the use of any item subject to the Regulations that has been or will be exported from the United States. For purposes of this paragraph, servicing means installation, maintenance, repair, modification or testing.

Third, pursuant to Section 1760(e) of the Export Control Reform Act (50 U.S.C. 4819(e)) and Sections 766.23 and 766.25 of the Regulations, any other person, firm, corporation, or business organization related to McKenzie by ownership, control, position of responsibility, affiliation, or other connection in the conduct of trade or business may also be made subject to the provisions of this Order in order to prevent evasion of this Order.

Fourth, in accordance with Part 756 of the Regulations, McKenzie may file an appeal of this Order with the Under Secretary of Commerce for Industry and Security. The appeal must be filed within 45 days from the date of this Order and must comply with the provisions of Part 756 of the Regulations.

Fifth, a copy of this Order shall be delivered to McKenzie and shall be published in the **Federal Register**.

Sixth, this Order is effective immediately and shall remain in effect until January 8, 2025.

John Sonderman,

Director, Office of Export Enforcement.

[FR Doc. 2021–24808 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–DT–P

[1] ECRA was enacted as part of the John S. McCain National Defense Authorization Act for Fiscal Year 2019, and as amended is codified at 50 U.S.C. 4801–4852. McKenzie's conviction post-dates ECRA's enactment on August 13, 2018.

[2] The Regulations are currently codified in the Code of Federal Regulations at 15 CFR parts 730–774 (2021).

[3] The Director, Office of Export Enforcement, is now the authorizing official for issuance of denial orders, pursuant to recent amendments to the Regulations (85 FR 73411, November 18, 2020).

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Order Denying Export Privileges; In the Matter of: Robert Herman Fleischer, 20003 N. 23rd Avenue, Apt. 250, Phoenix, AZ 85027

On August 4, 2017, in the U.S. District Court for the District of Arizona, Robert Herman Fleischer (''Fleischer'') was convicted of violating Section 38 of the Arms Export Control Act, 22 U.S.C. 2778 (2012)(''AECA''), by intentionally attempting to willfully and knowingly export and cause to be exported from the United States to Mexico 2,999 rounds of 7.62 x 39mm caliber ammunition, manufactured by Igman Arsenal, which are designated as defense articles on the United States Munitions List, without the required U.S. Department of State licenses. Fleischer was sentenced to 21 months in prison, with credit for time served, three years of supervised release, and a special assessment of $100. Fleischer was also placed on the U.S. Department of State Debarred List.

The Export Administration Regulations (''EAR'' or ''Regulations'') are administered and enforced by the U.S. Department of Commerce's Bureau of Industry and Security (''BIS'').[1] Section 766.25 of the Regulations provides, in pertinent part, that the ''Director of [BIS's] Office of Export Enforcement, in consultation with the Director of [BIS's] Office of Exporter Services, may deny the export privileges of any person who has been convicted of a violation of any of the statues set forth at 50 U.S.C. 4819 (e)(1)(B),''[2] including Section 38 of the AECA. 15 CFR 766.25(a).[3] The denial of export privileges under this provision may be for a period of up to 10 years from the date of the conviction. 15 CFR 766.25(d). In addition, pursuant to Section 750.8 of the Regulations, BIS's Office of Exporter Services may revoke any BIS-issued licenses in which the person has an interest at the time of his/her conviction.[4]

BIS received notice of Fleischer's conviction for violating Section 38 of the AECA, and pursuant to Section 766.25 of the Regulations, has provided notice and an opportunity for Fleischer to make a written submission to BIS. BIS has not received a written submission from Fleischer.

Based upon my review of the record and consultations with BIS's Office of Exporter Services, including its Director, and the facts available to BIS, I have decided to deny Fleischer's export privileges under the Regulations for a period of seven years from the date of Fleischer's conviction. The Office of Exporter Services has also decided to revoke any BIS-issued license in which Fleischer had an interest at the time of his conviction.

Accordingly, it is hereby *ordered:*

First, from the date of this Order until August 4, 2024, Robert Herman Fleischer, with a last known address of 20003 N. 23rd Avenue, Apt. 250, Phoenix, AZ 85027, and when acting for or on his behalf, his successors, assigns, employees, agents or representatives (''the Denied Person''), may not, directly or indirectly, participate in any way in any transaction involving any commodity, software or technology (hereinafter collectively referred to as ''item'') exported or to be exported from the United States that is subject to the Regulations, including, but not limited to:

A. Applying for, obtaining, or using any license, license exception, or export control document;

B. Carrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or engaging in any other activity subject to the Regulations; or

C. Benefitting in any way from any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or from any other activity subject to the Regulations.

Second, no person may, directly or indirectly, do any of the following:

A. Export or reexport to or on behalf of the Denied Person any item subject to the Regulations;

B. Take any action that facilitates the acquisition or attempted acquisition by the Denied Person of the ownership, possession, or control of any item subject to the Regulations that has been or will be exported from the United States, including financing or other support activities related to a transaction whereby the Denied Person acquires or attempts to acquire such ownership, possession or control;

C. Take any action to acquire from or to facilitate the acquisition or attempted acquisition from the Denied Person of any item subject to the Regulations that has been exported from the United States;

D. Obtain from the Denied Person in the United States any item subject to the Regulations with knowledge or reason to know that the item will be, or is intended to be, exported from the United States; or

E. Engage in any transaction to service any item subject to the Regulations that has been or will be exported from the United States and which is owned, possessed or controlled by the Denied Person, or service any item, of whatever origin, that is owned, possessed or controlled by the Denied Person if such service involves the use of any item subject to the Regulations that has been or will be exported from the United States. For purposes of this paragraph, servicing means installation, maintenance, repair, modification or testing.

Third, after notice and opportunity for comment as provided in Section 766.23 of the Regulations, any other person, firm, corporation, or business organization related to Fleischer by ownership, control, position of responsibility, affiliation, or other connection in the conduct of trade or business may also be made subject to the provisions of this Order in order to prevent evasion of this Order.

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[1] The Regulations are currently codified in the Code of Federal Regulations at 15 CFR Parts 730–774 (2021). The Regulations originally issued under the Export Administration Act of 1979, as amended, 50 U.S.C. 4601–4623 (Supp. III 2015) (''EAA''), which lapsed on August 21, 2001. The President, through Executive Order 13,222 of August 17, 2001 (3 CFR, 2001 Comp. 783 (2002)), which was extended by successive Presidential Notices, continued the Regulations in full force and effect under the International Emergnecy Economic Powers Act (50 U.S.C. 1701, *et seq.*) (''IEEPA''). On August 13, 2018, the President signed into law the John S. McCain National Defense Authorization Act for Fiscal Year 2019, which includes the Export Control Reform Act of 2018, 50 U.S.C. 4801–4852 (''ECRA''). While Section 1766 of ECRA repeals the provisions of the EAA (except for three sections which are inapplicable here), Section 1768 of ECRA provides, in pertinent part, that all rules and regulations that were made or issued under the EAA, including as continued in effect pursuant to IEEPA, and were in effect as of ECRA's date of enactment (August 13, 2018), shall continue in effect according to their terms until modified, superseded, set aside, or revoked through action undertaken pursuant to the authority provided under ECRA.

[2] The Director, Office of Export Enforcement, is now the authorizing official for issuance of denial orders, pursuant to recent amendments to the Regulations (85 FR 73411, November 18, 2020).

[3] As codified at the time of the underlying conviction at issue, Section 11(h)(1) of the EAA, as amended, provided that: ''No person convicted of a violation of this chapter (or any regulation, license, or older issued under this chapter), any regulation, license, or order issued under the International Emergnecy Economic Powers Act [50 U.S.C. 1701, *et seq.*], section 793, 794 or 798 of title 18, section 783(b) of this title, or section 2778 of title 22 shall be eligible, at the discretion of the Secretary, to apply for or use any export license under this chapter for a period of up to 10 years from the date of conviction. The Secretary may revoke any export license under this chapter in which such person has an interest at the time of conviction.'' 50 U.S.C. 4610(h)(1).

[4] *See* notes 1 and 3, *supra.*

Fourth, in accordance with Part 756 of the Regulations, Fleischer may file an appeal of this Order with the Under Secretary of Commerce for Industry and Security. The appeal must be filed within 45 days from the date of this Order and must comply with the provisions of Part 756 of the Regulations.

Fifth, a copy of this Order shall be delivered to Fleischer and shall be published in the **Federal Register**.

Sixth, this Order is effective immediately and shall remain in effect until August 4, 2024.

John Sonderman,

Director, Office of Export Enforcement.

[FR Doc. 2021–24805 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–DT–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

In the Matter of: Si Mong Park, 10386 East Painted Turtle Lane; Tucson, AZ 85747; Order Denying Export Privileges

On September 14, 2020, in the U.S. District Court for the District of Columbia, Si Mong Park (''Park'') was convicted of violating Section 38 of the Arms Export Control Act (22 U.S.C. 2778) (''AECA''). Specifically, Park was convicted of knowingly and willfully exporting and causing to be exported from the United States to South Korea, defense articles, that is, technical data related to launch vehicles, guided missiles, ballistic missiles, rockets, torpedoes, bombs and mines, and technical data related to enumerated aircraft and aircraft related articles, which are all designated as defense articles on the United States Munitions List, without having first obtained from the Department of State a license for such export or written authorization for such export. Park was sentenced to 21 months in prison, 36 months of supervised release and a $100 assessment.

Pursuant to Section 1760(e) of the Export Control Reform Act (''ECRA''),[1] the export privileges of any person who has been convicted of certain offenses, including, but not limited to, Section 38 of the AECA, may be denied for a period of up to ten (10) years from the date of his/her conviction. 50 U.S.C. 4819(e) (Prior Convictions). In addition, any Bureau of Industry and Security (''BIS'') licenses or other authorizations issued under ECRA, in which the person had an interest at the time of the conviction, may be revoked. *Id.*

BIS received notice of Park's conviction for violating Section 38 of the AECA, and has provided notice and opportunity for Park to make a written submission to BIS, as provided in Section 766.25 of the Export Administration Regulations (''EAR'' or the ''Regulations''). 15 CFR 766.25.[2] BIS has not received a written submission from Park.

Based upon my review of the record and consultations with BIS's Office of Exporter Services, including its Director, and the facts available to BIS, I have decided to deny Park's export privileges under the Regulations for a period of seven years from the date of Park's conviction. The Office of Exporter Services has also decided to revoke any BIS-issued licenses in which Park had an interest at the time of his conviction.[3]

Accordingly, it is hereby *ordered*:

First, from the date of this Order until September 14, 2027, Si Mong Park, with a last known address of 10386 East Painted Turtle Lane, Tucson, AZ 85747, and when acting for or on his behalf, his successors, assigns, employees, agents or representatives (''the Denied Person''), may not directly or indirectly participate in any way in any transaction involving any commodity, software or technology (hereinafter collectively referred to as ''item'') exported or to be exported from the United States that is subject to the Regulations, including, but not limited to:

A. Applying for, obtaining, or using any license, license exception, or export control document;

B. Carrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or engaging in any other activity subject to the Regulations; or

C. Benefitting in any way from any transaction involving any item exported or to be exported from the United States that is subject to the Regulations, or from any other activity subject to the Regulations.

Second, no person may, directly or indirectly, do any of the following:

A. Export, reexport, or transfer (in-country) to or on behalf of the Denied Person any item subject to the Regulations;

B. Take any action that facilitates the acquisition or attempted acquisition by the Denied Person of the ownership, possession, or control of any item subject to the Regulations that has been or will be exported from the United States, including financing or other support activities related to a transaction whereby the Denied Person acquires or attempts to acquire such ownership, possession or control;

C. Take any action to acquire from or to facilitate the acquisition or attempted acquisition from the Denied Person of any item subject to the Regulations that has been exported from the United States;

D. Obtain from the Denied Person in the United States any item subject to the Regulations with knowledge or reason to know that the item will be, or is intended to be, exported from the United States; or

E. Engage in any transaction to service any item subject to the Regulations that has been or will be exported from the United States and which is owned, possessed or controlled by the Denied Person, or service any item, of whatever origin, that is owned, possessed or controlled by the Denied Person if such service involves the use of any item subject to the Regulations that has been or will be exported from the United States. For purposes of this paragraph, servicing means installation, maintenance, repair, modification or testing.

Third, pursuant to Section 1760(e) of the Export Control Reform Act (50 U.S.C. 4819(e)) and Sections 766.23 and 766.25 of the Regulations, any other person, firm, corporation, or business organization related to Park by ownership, control, position of responsibility, affiliation, or other connection in the conduct of trade or business may also be made subject to the provisions of this Order in order to prevent evasion of this Order.

Fourth, in accordance with Part 756 of the Regulations, Park may file an appeal of this Order with the Under Secretary of Commerce for Industry and Security. The appeal must be filed within 45 days from the date of this Order and must comply with the provisions of Part 756 of the Regulations.

Fifth, a copy of this Order shall be delivered to Park and shall be published in the **Federal Register**.

[1] ECRA was enacted as part of the John S. McCain National Defense Authorization Act for Fiscal Year 2019, and as amended is codified at 50 U.S.C. 4801–4852. Park's conviction post-dates ECRA's enactment on August 13, 2018.

[2] The Regulations are currently codified in the Code of Federal Regulations at 15 CFR Parts 730–774 (2021).

[3] The Director, Office of Export Enforcement, is now the authorizing official for issuance of denial orders, pursuant to recent amendments to the Regulations (85 FR 73411, November 18, 2020).

Sixth, this Order is effective immediately and shall remain in effect until September 14, 2027.

John Sonderman,

Director, Office of Export Enforcement.

[FR Doc. 2021–24806 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–DT–P

DEPARTMENT OF COMMERCE

International Trade Administration

[C–489–806]

Certain Pasta From the Republic of Turkey: Final Results of Countervailing Duty Administrative Review; 2019

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (Commerce) determines that Bessan Makarna Gida San. Ve Tic. A.S. (Bessan), a producer/exporter of certain pasta from the Republic of Turkey (Turkey) did not receive countervailable subsidies during the period of review (POR), January 1, 2019, through December 31, 2019.

DATES: Applicable November 15, 2021.

FOR FURTHER INFORMATION CONTACT: Brontee Jeffries or Theodore Pearson, AD/CVD Operations, Office I, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–4656 or (202) 482–2631, respectively.

SUPPLEMENTARY INFORMATION:

Background

On August 3, 2021, Commerce published the *Preliminary Results* and invited parties to comment.[1] No interested party submitted comments. Commerce conducted this review in accordance with section 751(a)(1)(A) of the Tariff Act of 1930, as amended (the Act).

Scope of the Order [2]

The merchandise covered by the order is pasta from Turkey. For a complete description of the scope, *see* the *Preliminary Results.*[3]

Changes Since the Preliminary Results

As no party submitted comments on the *Preliminary Results,* we made no changes in the final results of this review.

Final Results of the Administrative Review

In accordance with section 777A(e)(1) of the Act and 19 CFR 351.221(b)(5), we determine that Bessan did not receive countervailable subsidies during the POR:

Company	Subsidy rate (percent *ad valorem)*
Bessan Makarna Gida San. Ve Tic. A.S	0.00

Assessment Rates

Commerce shall determine, and CBP shall assess, countervailing duties on all appropriate entries covered by this review, pursuant to section 751(a)(2)(C) of the Act and 19 CFR 351.212(b)(2). Because we determined that Bessan did not receive countervailable subsidies in the final results of this review, we intend to instruct CBP to liquidate the appropriate entries without regard to countervailing duties in accordance with 19 CFR 351.212(b)(2) and 19 CFR 351.106(c)(1).

Commerce intends to issue appropriate assessment instructions to CBP no earlier than 35 days after the date of this publication of the final results of this review in the **Federal Register**. If a timely summons is filed at the U.S. Court of International Trade, the assessment instructions will direct CBP not to liquidate relevant entries until the time for parties to file a request for a statutory injunction has expired (*i.e.,* within 90 days of publication).

Cash Deposit Requirements

Pursuant to section 751(a)(2)(C) of the Act, Commerce also intends to instruct CBP to collect cash deposits of estimated countervailing duties at the appropriate rates. For shipments of subject merchandise by Bessan entered, or withdrawn from warehouse, for consumption on or after the date of publication of these final results, the cash deposit rate will be zero. For all non-reviewed firms, CBP will continue to collect cash deposits of estimated countervailing duties at the most recent company-specific or all-others rate applicable to the company, as appropriate. These cash deposit requirements, when imposed, shall remain in effect until further notice.

Administrative Protective Order

This notice serves as a reminder to parties subject to administrative protective order (APO) of their responsibility concerning the destruction of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3), which continues to govern business proprietary information in this segment of the proceeding. Timely written notification of return or destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and the terms of an APO is sanctionable violation.

Notification to Interested Parties

The final results of this review are issued and published in accordance with sections 751(a)(1) and 777(i) of the Act.

Dated: November 8, 2021.

Ryan Majerus,

Deputy Assistant Secretary for Policy and Negotiations, Performing the Non-Exclusive Functions and Duties of The Assistant Secretary for Enforcement and Compliance.

[FR Doc. 2021–24857 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–832]

Pure Magnesium From the People's Republic of China: Preliminary Results of Antidumping Duty Administrative Review; 2020–2021

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (Commerce) is conducting the administrative review of the antidumping duty (AD) order on pure magnesium from the People's Republic of China (China). The period of review (POR) is May 1, 2020, through April 30, 2021. Commerce preliminarily determines that Tianjin Magnesium International Co., Ltd. (TMI) and Tianjin Magnesium Metal Co., Ltd. (TMM) (collectively, TMI/TMM) did not have any shipments of subject merchandise during the POR. We invite interested parties to comment on these preliminary results.

DATES: Applicable November 15, 2021.

FOR FURTHER INFORMATION CONTACT: Deborah Cohen, AD/CVD Operations, Office III, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–4521.

SUPPLEMENTARY INFORMATION:

[1] *See Certain Pasta from the Republic of Turkey: Preliminary Results of Countervailing Duty Administrative Review; 2019,* 86 FR 41816 (August 3, 2021) (*Preliminary Results*), and accompanying Preliminary Decision Memorandum (PDM).

[2] *See Preliminary Results* PDM.

[3] *See Preliminary Results* PDM.

Background

On May 3, 2021, Commerce published in the **Federal Register** a notice of opportunity to request an administrative review of the *Order* on pure magnesium from China for the POR.[1] On May 28, 2021, in response to a timely request from US Magnesium LLC (the petitioner),[2] and in accordance with section 751(a) of the Tariff Act of 1930, as amended (the Act), and 19 CFR 351.221(c)(1)(i), we initiated an administrative review of the *Order* with respect to TMI/TMM.[3]

Scope of the Order

The product covered by the *Order* is pure magnesium from China, regardless of chemistry, form or size, unless expressly excluded from the scope of the order. Pure magnesium is a metal or alloy containing by weight primarily the element magnesium and produced by decomposing raw materials into magnesium metal. Pure primary magnesium is used primarily as a chemical in the aluminum alloying, desulfurization, and chemical reduction industries. In addition, pure magnesium is used as an input in producing magnesium alloy. Pure magnesium encompasses products (including, but not limited to, butt ends, stubs, crowns and crystals) with the following primary magnesium contents:

(1) Products that contain at least 99.95% primary magnesium, by weight (generally referred to as ''ultra pure'' magnesium) Magnesium Alloy''[4] and are thus outside the scope of the existing antidumping orders on magnesium from China (generally referred to as ''alloy'' magnesium).

(2) Products that contain less than 99.95%, but not less than 99.8%, primary magnesium, by weight (generally referred to as ''pure'' magnesium); and

(3) Products that contain 50% or greater, but less than 99.8% primary magnesium, by weight, and that do not conform to ASTM specifications for alloy magnesium (generally referred to as ''off-specification pure'' magnesium).

''Off-specification pure'' magnesium is pure primary magnesium containing magnesium scrap, secondary magnesium, oxidized magnesium or impurities (whether or not intentionally added) that cause the primary magnesium content to fall below 99.8% by weight. It generally does not contain, individually or in combination, 1.5% or more, by weight, of the following alloying elements: Aluminum, manganese, zinc, silicon, thorium, zirconium and rare earths.

Excluded from the scope of the *Order* are alloy primary magnesium (that meets specifications for alloy magnesium), primary magnesium anodes, granular primary magnesium (including turnings, chips and powder) having a maximum physical dimension (*i.e.,* length or diameter) of one inch or less, secondary magnesium (which has pure primary magnesium content of less than 50% by weight), and remelted magnesium whose pure primary magnesium content is less than 50% by weight.

Pure magnesium products covered by the *Order* are currently classifiable under Harmonized Tariff Schedule of the United States (HTSUS) subheadings 8104.11.00, 8104.19.00, 8104.20.00, 8104.30.00, 8104.90.00, 3824.90.11, 3824.90.19 and 9817.00.90. Although the HTSUS subheadings are provided for convenience and customs purposes, the written description of the scope is dispositive.

Preliminary Determination of No Shipments

We received timely submissions from TMI/TMM certifying that they did not have sales, shipments, or exports of subject merchandise to the United States during the POR.[5] On July 26, 2021, we requested the U.S. Customs and Border Protection (CBP) data file of entries of subject merchandise imported into the United States during the POR, and exported by TMM/TMI.[6] This query returned no entries during the POR.[7] Additionally, on August 3, 2021, Commerce submitted a no-shipments inquiry to CBP with regard to TMI/TMM, to which CBP responded that it found no shipments of subject merchandise by TMI/TMM during the POR.[8]

Accordingly, and consistent with our practice, we preliminarily determine that TMI/TMM had no shipments and, therefore, no reviewable entries during the POR. In addition, we find it is not appropriate to rescind the review with respect to these companies, but rather to complete the review with respect to TMI/TMM and issue appropriate instructions to CBP based on the final results of the review, consistent with our practice in non-market economy (NME) cases.[9]

Public Comment

Interested parties are invited to comment on the preliminary results and may submit case briefs and/or written comments, filed electronically via Enforcement and Compliance's Antidumping Duty and Countervailing Duty Centralized Electronic Service System (ACCESS), within 30 days after the date of publication of these preliminary results of review.[10] ACCESS is available to registered users at *https://access.trade.gov.* Rebuttal briefs, limited to issues raised in the case briefs, must be filed within seven days after the time limit for filing case briefs.[11] Parties who submit case or rebuttal briefs in this proceeding are requested to submit with each argument a statement of the issue, a brief summary of the argument, and a table of authorities.[12] Note that Commerce has temporarily modified certain portions of its requirements for serving documents containing business proprietary information, until further notice.[13]

Interested parties who wish to request a hearing, or to participate if one is requested, must submit a written request to Commerce within 30 days of the date of publication of this notice.[14] Requests should contain: (1) The party's name, address, the telephone number; (2) the number of participants; and (3) a list of issues to be discussed. Issues

[1] *See Antidumping or Countervailing Duty Order, Finding, or Suspended Investigation; Opportunity To Request Administrative Review,* 86 FR 23346 (May 3, 2021); *see also Notice of Antidumping Duty Orders: Pure Magnesium from the People's Republic of China, the Russian Federation and Ukraine; Notice of Amended Final Determination of Sales at Less Than Fair Value: Antidumping Duty Investigation of Pure Magnesium from the Russian Federation,* 60 FR 25691 (May 12, 1995) (*Order*).

[2] *See* Petitioner's Letter, ''Pure Magnesium from the People's Republic of China: Request for Administrative Review,'' dated May 28, 2021.

[3] *See Initiation of Antidumping and Countervailing Duty Administrative Reviews,* 86 FR 35481 (July 6, 2021).

[4] The meaning of this term is the same as that used by the American Society for Testing and Materials (ATSM) in its Annual Book for ASTM Standards: Volume 01.02 Aluminum and Magnesium Alloys.

[5] *See* TMI's Letter, ''Pure Magnesium from the People's Republic of China; A–570–832; No Shipment Certification,'' dated July 14, 2021; *see also* TMM's Letter, ''Pure Magnesium from the People's Republic of China; A–570–832; No Shipment Certification,'' dated July 14, 2021.

[6] *See* Memorandum, ''Antidumping Duty Administrative Review of Pure Magnesium from the People's Republic of China, 05/01/2020–04/30/2021: Entry Data and No Shipment Inquiry,'' dated August 31, 2021 at Attachment 1.

[7] *Id.* at Attachment 2.

[8] *Id.* at Attachment 3.

[9] *See Glycine from the People's Republic of China: Final Results of Antidumping Duty Administrative Review 2014–2015,* 81 FR 72567 (October 20, 2016), and the ''Assessment Rates'' section, below.

[10] *See* 19 CFR 351.309(c)(1)(ii).

[11] *See* 19 CFR 351.309(d)(1) and (2); *see also Temporary Rule Modifying AD/CVD Service Requirements Due to COVID–19; Extension of Effective Period,* 85 FR 41363 (July 10, 2020) (*Temporary Rule*).

[12] *See* 19 CFR 351.309(c) and (d); *see also* 19 CFR 351.303 (for general filing requirements).

[13] *See Temporary Rule.*

[14] *See* 19 CFR 351.310(c).

raised in the hearing will be limited to those raised in the respective case and rebuttal briefs. If a request for a hearing is made, parties will be notified of the time and date for the hearing to be held.[15] Commerce intends to issue the final results of this administrative review, which will include the results of our analysis of all issues raised in the case briefs, within 120 days of publication of these preliminary results in the **Federal Register**, unless extended, pursuant to section 751(a)(3)(A) of the Act.

Assessment Rates

Upon issuance of the final results of this review, Commerce will determine, and CBP will assess, antidumping duties on all appropriate entries covered by this review.[16] Commerce intends to issue assessment instructions to CBP no earlier than 35 days after the date of publication of the final results of this review in the **Federal Register**. If a timely summons is filed at the U.S. Court of International Trade, the assessment instructions will direct CBP not to liquidate relevant entries until the time for parties to file a request for a statutory injunction has expired (*i.e.,* within 90 days of publication). Pursuant to Commerce's practice in NME cases, if we continue to determine in the final results that TMI/TMM had no shipments of subject merchandise, any suspended entries of subject merchandise during the POR from these companies will be liquidated at the China-wide rate.[17]

Cash Deposit Requirements

The following cash deposit requirements will be effective upon publication of the final results of this administrative review for all shipments of the subject merchandise entered, or withdrawn from warehouse, for consumption on or after the publication date of the final results of review, as provided for by section 751(a)(2)(C) of the Act: (1) For TMI/TMM, which claimed no shipments, the cash deposit rate will remain unchanged from the rate assigned to TMI/TMM in the most recently completed review of the companies; (2) for previously investigated or reviewed Chinese and non-Chinese exporters who are not under review in this segment of the proceeding but who have separate rates, the cash deposit rate will continue to be the exporter-specific rate published for the most recent period; (3) for all Chinese exporters of subject merchandise that have not been found to be entitled to a separate rate, the cash deposit rate will be the China-wide rate of 111.73 percent;[18] and (4) for all non-Chinese exporters of subject merchandise which have not received their own rate, the cash deposit rate will be the rate applicable to Chinese exporter(s) that supplied that non-Chinese exporter. These deposit requirements, when imposed, shall remain in effect until further notice.

Notification to Importers

This notice also serves as a preliminary reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in Commerce's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

Notification to Interested Parties

These preliminary results of review are issued and published in accordance with sections 751(a)(1) and 777(i)(1) of the Act and 19 CFR 351.221(b)(4).

Dated: November 8, 2021.

Ryan Majerus,

Deputy Assistant Secretary for Policy and Negotiations, performing the non-exclusive functions and duties of the Assistant Secretary for Enforcement and Compliance.

[FR Doc. 2021–24820 Filed 11–12–21; 8:45 am]

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[15] *See* 19 CFR 310(d).

[16] *See* 19 CFR 351.212(b)(1).

[17] For a full discussion of this practice, *see Non-Market Economy Antidumping Proceedings: Assessment of Antidumping Duties,* 76 FR 65694 (October 24, 2011).

[18] *See Pure Magnesium from the People's Republic of China: Final Results of the 2008–2009 Antidumping Duty Administrative Review of the Antidumping Duty Order,* 75 FR 80791 (December 23, 2010).

DEPARTMENT OF COMMERCE

International Trade Administration

[A–301–803]

Citric Acid and Certain Citrate Salts From Colombia: Final Results of Antidumping Duty Administrative Review; 2019–2020

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (Commerce) determines that Sucroal S.A. (Sucroal), a producer/exporter of citric acid and certain citrate salts (citric acid) from Colombia, sold subject merchandise at prices below normal value during the period of review (POR) July 1, 2019, through June 30, 2020.

DATES: Applicable November 15, 2021.

FOR FURTHER INFORMATION CONTACT: David Lindgren, AD/CVD Operations, Office III, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Ave. NW, Washington, DC 20230; telephone: (202) 482–1671.

SUPPLEMENTARY INFORMATION:

Background

On July 22, 2021, Commerce published the *Preliminary Results.*[1] This review covers one producer/exporter of the subject merchandise, Sucroal. We invited parties to comment on the *Preliminary Results.* No party submitted comments. Accordingly, the final results remain unchanged from the *Preliminary Results.*

Scope of the Order[2]

The merchandise covered by the *Order* includes all grades and granulation sizes of citric acid, sodium citrate, and potassium citrate in their unblended forms, whether dry or in solution, and regardless of packaging type. The scope also includes blends of citric acid, sodium citrate, and potassium citrate; as well as blends with other ingredients, such as sugar, where the unblended form(s) of citric acid, sodium citrate, and potassium citrate constitute 40 percent or more, by weight, of the blend.

The scope also includes all forms of crude calcium citrate, including dicalcium citrate monohydrate, and tricalcium citrate tetrahydrate, which are intermediate products in the production of citric acid, sodium citrate, and potassium citrate.

The scope includes the hydrous and anhydrous forms of citric acid, the dihydrate and anhydrous forms of sodium citrate, otherwise known as citric acid sodium salt, and the monohydrate and monopotassium forms of potassium citrate. Sodium citrate also includes both trisodium citrate and monosodium citrate which are also known as citric acid trisodium salt and citric acid monosodium salt, respectively.

The scope does not include calcium citrate that satisfies the standards set forth in the United States Pharmacopeia and has been mixed with a functional

[1] *See Citric Acid and Certain Citrate Salts from Colombia: Preliminary Results of Antidumping Duty Administrative Review; 2019–2020,* 86 FR 38677 (July 22, 2021) (*Preliminary Results*).

[2] *See Citric Acid and Certain Citrate Sales from Belgium, Colombia and Thailand: Antidumping Duty Orders,* 83 FR 35214 (July 25, 2018) (*Order*).

excipient, such as dextrose or starch, where the excipient constitutes at least 2 percent, by weight, of the product.

Citric acid and sodium citrate are classifiable under 2918.14.0000 and 2918.15.1000 of the Harmonized Tariff Schedule of the United States (HTSUS), respectively. Potassium citrate and crude calcium citrate are classifiable under 2918.15.5000 and, if included in a mixture or blend, 3824.99.9295 of the HTSUS. Blends that include citric acid, sodium citrate, and potassium citrate are classifiable under 3824.99.9295 of the HTSUS. Although the HTSUS subheadings are provided for convenience and customs purposes, the written description of the merchandise is dispositive.

Final Results of the Administrative Review

As a result of this administrative review, we determine that the following weighted-average dumping margin exists for the POR:

Producer/exporter	Estimated weighted-average dumping margin (percent)
Sucroal S.A	2.50

Disclosure

Normally, Commerce will disclose to the parties in a proceeding the calculations performed in connection with a final results of review within five days of any public announcement or, if there is no public announcement, within five days of the date of publication of the notice of final results in the **Federal Register**, in accordance with 19 CFR 351.224(b). However, Commerce made no adjustments to the margin calculation methodology used in the *Preliminary Results;* therefore, there are no calculations to disclose for the final results.

Assessment Rates

Pursuant to section 751(a)(2)(C) of the Tariff Act of 1930, as amended (the Act), and 19 CFR 351.212(b), Commerce has determined, and U.S. Customs and Border Protection (CBP) shall assess, antidumping duties on all appropriate entries of subject merchandise in accordance with the final results of this review. For Sucroal, because its weighted-average dumping margin is not zero or *de minimis* (*i.e.,* less than 0.5 percent), Commerce has calculated importer-specific antidumping duty (AD) assessment rates. We calculated importer- (or customer-) specific *ad valorem* AD assessment rates by dividing the total amount of dumping calculated for the importer's examined sales by the total entered value of the same sales for that importer, in accordance with 19 CFR 351.212(b)(1).

Commerce intends to issue assessment instructions to CBP no earlier than 35 days after the date of publication of the final results of this review in the **Federal Register**, in accordance with 19 CFR 356.8(a). If a timely summons is filed at the U.S. Court of International Trade, the assessment instructions will direct CBP not to liquidate relevant entries until the time for parties to file a request for a statutory injunction has expired (*i.e.,* within 90 days of publication).

Cash Deposit Requirements

The following deposit requirements will be effective upon publication of the notice of these final results for all shipments of citric acid from Colombia entered, or withdrawn from warehouse, for consumption on or after the date of publication provided by section 751(a)(2) of the Act: (1) The cash deposit rate for Sucroal will be equal to the dumping margin established in the final results of this review; (2) for merchandise exported by producers or exporters not covered in this review but covered in a completed prior segment of the proceeding, the cash deposit rate will continue to be the company-specific rate published for the most recently-completed segment of this proceeding in which the producer and/or exporter participated; (3) if the exporter is not a firm covered in this review, a prior review, or the original less-than-fair-value investigation but the producer is, then the cash deposit rate will be the rate established for the most recently completed segment of the proceeding for the producer of the merchandise; and (4) the cash deposit rate for all other producers or exporters will continue to be 28.48 percent, the all-others rate established in the less-than-fair-value investigation.[3] These cash deposit requirements, when imposed, shall remain in effect until further notice.

Notification to Importers

This notice serves as a final reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in Commerce's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

[3] *See Order.*

Notification Regarding Administrative Protective Orders

This notice also serves as a reminder to parties subject to administrative protective order (APO) of their responsibility concerning the return or destruction of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3), which continues to govern business proprietary information in this segment of the proceeding. Timely written notification of the return or destruction of APO materials, or conversion to judicial protective order, is hereby requested. Failure to comply with the regulations and the terms of an APO is a sanctionable violation.

Notification to Interested Parties

We are issuing and publishing these results in accordance with sections 751(a)(1) and 777(i) of the Act and 19 CFR 351.221(b)(5).

Dated: November 5, 2021.

Ryan Majerus,

Deputy Assistant Secretary for Policy and Negotiations, performing the non-exclusive functions and duties of the Assistant Secretary for Enforcement and Compliance.

[FR Doc. 2021–24823 Filed 11–12–21; 8:45 am]

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DEPARTMENT OF COMMERCE

International Trade Administration

[A–423–813]

Citric Acid and Certain Citrate Salts From Belgium: Final Results of Antidumping Duty Administrative Review; 2019–2020

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (Commerce) determines that S.A. Citrique Belge N.V. (Citrique Belge), a producer/exporter of citric acid and certain citrate salts (citric acid) from Belgium, did not sell subject merchandise at prices below normal value during the period of review (POR), July 1, 2019, through June 30, 2020.

DATES: Applicable November 15, 2021.

FOR FURTHER INFORMATION CONTACT: David Lindgren, AD/CVD Operations, Office III, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–1671.

SUPPLEMENTARY INFORMATION:

Background

On July 22, 2021, Commerce published the *Preliminary Results* of the administrative review of the antidumping duty (AD) order on citric acid from Belgium.[1] This review covers one producer/exporter of the subject merchandise, Citrique Belge. We invited parties to comment on the *Preliminary Results.* No party submitted comments. Accordingly, the final results remain unchanged from the *Preliminary Results.*

Scope of the Order

The merchandise covered by this *Order* includes all grades and granulation sizes of citric acid, sodium citrate, and potassium citrate in their unblended forms, whether dry or in solution, and regardless of packaging type. The scope also includes blends of citric acid, sodium citrate, and potassium citrate; as well as blends with other ingredients, such as sugar, where the unblended form(s) of citric acid, sodium citrate, and potassium citrate constitute 40 percent or more, by weight, of the blend.

The scope also includes all forms of crude calcium citrate, including dicalcium citrate monohydrate, and tricalcium citrate tetrahydrate, which are intermediate products in the production of citric acid, sodium citrate, and potassium citrate.

The scope includes the hydrous and anhydrous forms of citric acid, the dihydrate and anhydrous forms of sodium citrate, otherwise known as citric acid sodium salt, and the monohydrate and monopotassium forms of potassium citrate. Sodium citrate also includes both trisodium citrate and monosodium citrate which are also known as citric acid trisodium salt and citric acid monosodium salt, respectively.

The scope does not include calcium citrate that satisfies the standards set forth in the United States Pharmacopeia and has been mixed with a functional excipient, such as dextrose or starch, where the excipient constitutes at least 2 percent, by weight, of the product.

Citric acid and sodium citrate are classifiable under 2918.14.0000 and 2918.15.1000 of the Harmonized Tariff Schedule of the United States (HTSUS), respectively. Potassium citrate and crude calcium citrate are classifiable under 2918.15.5000 and, if included in a mixture or blend, 3824.99.9295 of the HTSUS. Blends that include citric acid, sodium citrate, and potassium citrate are classifiable under 3824.99.9295 of the HTSUS. Although the HTSUS subheadings are provided for convenience and customs purposes, the written description of the merchandise is dispositive.

Final Results of the Administrative Review

As a result of this administrative review, Commerce determines that the following dumping margin exists for the POR:

Producer/exporter	Weighted-average dumping margin (percent)
S.A. Citrique Belge N.V	0.00

Disclosure

Normally, Commerce will disclose to the parties in a proceeding the calculations performed in connection with a final results of review within five days of any public announcement or, if there is no public announcement, within five days of the date of publication of the notice of final results in the **Federal Register**, in accordance with 19 CFR 351.224(b). However, Commerce made no adjustments to the margin calculation methodology used in the *Preliminary Results;* therefore, there are no calculations to disclose for the final results.

Assessment Rates

Pursuant to section 751(a)(2)(C) of the Tariff Act of 1930, as amended (the Act), and 19 CFR 351.212(b), Commerce has determined, and U.S. Customs and Border Protection (CBP) shall assess, antidumping duties on all appropriate entries of subject merchandise in accordance with the final results of this review. Because the rate assigned to Citrique Belge is zero, Commerce will instruct CBP to liquidate the appropriate entries without regard to antidumping duties.

Commerce intends to issue assessment instructions to CBP no earlier than 35 days after the date of publication of the final results of this review in the **Federal Register**, in accordance with 19 CFR 356.8(a). If a timely summons is filed at the U.S. Court of International Trade, the assessment instructions will direct CBP not to liquidate relevant entries until the time for parties to file a request for a statutory injunction has expired (*i.e.,* within 90 days of publication).

Cash Deposit Requirements

The following deposit requirements will be effective upon publication of the notice of these final results for all shipments of citric acid from Belgium entered, or withdrawn from warehouse, for consumption on or after the date of publication provided by section 751(a)(2) of the Act: (1) The cash deposit rate for Citrique Belge will be zero; (2) for merchandise exported by producers or exporters not covered in this review but covered in a completed prior segment of the proceeding, the cash deposit rate will continue to be the company-specific rate published for the most recently completed segment of this proceeding in which the producer and/or exporter participated; (3) if the exporter is not a firm covered in this review, a prior review, or the original less-than-fair-value investigation but the producer is, then the cash deposit rate will be the rate established for the most recently completed segment of the proceeding for the producer of the merchandise; and (4) the cash deposit rate for all other producers or exporters will continue to be 19.30 percent, the all-others rate established in the less-than-fair-value investigation.[2] These cash deposit requirements, when imposed, shall remain in effect until further notice.

Notification to Importers

This notice serves as a final reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in Commerce's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

Notification Regarding Administrative Protective Order

This notice also serves as a reminder to parties subject to the administrative protective order (APO) of their responsibility concerning the return or destruction of proprietary information

[1] *See Citric Acid and Certain Citrate Salts from Belgium: Preliminary Results of Antidumping Duty Administrative Review; 2019–2020,* 86 FR 38681 (July 22, 2021) (*Preliminary Results*).

[2] *See Citric Acid and Certain Citrate Salts from Belgium, Colombia and Thailand: Antidumping Duty Orders,* 83 FR 35214 (July 25, 2018).

disclosed under the APO in accordance with 19 CFR 351.305(a)(3), which continues to govern business proprietary information in this segment of the proceeding. Timely written notification of the return or destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and terms of an APO is a sanctionable violation.

Notification to Interested Parties

We are issuing and publishing this notice in accordance with sections 751(a)(1) and 777(i)(1) of the Act, and 19 CFR 351.221(b)(5).

Dated: November 5, 2021.

Ryan Majerus,

Deputy Assistant Secretary for Policy and Negotiations, Performing the Non-Exclusive Functions and Duties of The Assistant Secretary for Enforcement and Compliance.

[FR Doc. 2021–24822 Filed 11–12–21; 8:45 am]

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DEPARTMENT OF COMMERCE

International Trade Administration

[A–475–818]

Certain Pasta From Italy: Final Results of Antidumping Duty Administrative Review; 2019–2020

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (Commerce) determines that certain pasta (pasta) from Italy was sold in the United States at less than normal value during the period of review (POR) July 1, 2019, through June 30, 2020.

DATES: Applicable November 15, 2021.

FOR FURTHER INFORMATION CONTACT: Jonathan Hall-Eastman and John Hoffner, AD/CVD Operations, Office III, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–1468 and (202) 482–3315, respectively.

SUPPLEMENTARY INFORMATION:

Background

On August 3, 2021, Commerce published the *Preliminary Results.*[1] On September 2, 2021, Commerce received case briefs on behalf of Liguori Pastificio dal 1820 S.p.A./Pastificio Della Forma S.r.l. (Liguori/Della Forma) and La Molisana S.p.A. (La Molisana).[2] No interested party filed a rebuttal brief. For a complete description of the events that occurred since the *Preliminary Results,* see the Issues and Decision Memorandum.[3]

Scope of the Order

The products covered by this order are certain pasta from Italy. For a full description of the scope, *see* the Issues and Decision Memorandum.

Analysis of Comments Received

All issues raised in the case briefs are addressed in the Issues and Decision Memorandum. A list of the issues that parties raised and to which we responded in the Issues and Decision Memorandum is attached to this notice as an Appendix. The Issues and Decision Memorandum is a public document and is on file electronically via Enforcement and Compliance's Antidumping and Countervailing Duty Centralized Electronic Service System (ACCESS). ACCESS is available to registered users at *https://access.trade.gov.* In addition, a complete version of the Issues and Decision Memorandum can be accessed directly at *https://access.trade.gov/public/FRNoticesListLayout.aspx.*

Changes Since the Preliminary Results

No changes were made from the *Preliminary Results.*

Rates for Companies Not Selected for Individual Examination

The statute and Commerce's regulations do not address the establishment of a rate to be applied to individual companies not selected for examination when Commerce limits its examination in an administrative review pursuant to section 777A(c)(2) of the Tariff Act of 1930, as amended (the Act). Generally, Commerce looks to section 735(c)(5) of the Act, which provides instructions for calculating the all-others rate in an investigation, for guidance when calculating the rate for companies which we did not individually examine in an administrative review. Section 735(c)(5)(A) of the Act establishes a preference to avoid using rates which are zero, *de minimis,* or based entirely on facts available (FA) in calculating an all-others rate. Accordingly, Commerce's practice in administrative reviews has been to average the weighted-average dumping margins for the companies selected for individual examination in the administrative review, excluding rates that are zero, *de minimis,* or based entirely on FA.[4] For these final results of review, we calculated a weighted-average dumping margin for La Molisana that is not zero, *de minimis,* or based entirely on FA. Therefore, consistent with our practice, we have assigned the companies not selected for individual examination the weighted-average dumping margin calculated for La Molisana.

Final Results of the Review

Commerce determines that the following weighted-average dumping margin exists for the period July 1, 2019, through June 30, 2020:

Exporter or producer	Weighted-average dumping margin (percent)
La Molisana S.p.A	1.61
Liguori Pastificio dal 1820 S.p.A. and Pastificio Della Forma S.r.l	0.00
Review-Specific Average Rate Applicable to the Following Companies	
Agritalia S.r.L	1.61
Armonie D'Italia srl	1.61
F. Divella S.p.A	1.61
Pasta Zara, S.p.A./Ghigi 1870 S.p.A	1.61
Pastificio C.A.M.S. Srl	1.61
Pastificio Fratelli De Luca S.r.l.	1.61

Assessment Rate

Pursuant to section 751(a)(2)(A) of the Act, and 19 CFR 351.212(b)(1), Commerce shall determine, and U.S. Customs and Border Protection (CBP) shall assess, antidumping duties on all appropriate entries covered by this review.

For the individually examined companies with a weighted-average dumping margin that is not zero, *de minimis* or based on total FA, Commerce has calculated importer-specific antidumping duty assessment rates. For La Molisana, we calculated importer-specific antidumping duty

[1] *See Certain Pasta from Italy: Preliminary Results of Antidumping Duty Administrative Review; 2019–2020,* 86 FR 41827 (August 3, 2021) (*Preliminary Results*), and accompanying Preliminary Decision Memorandum.

[2] *See* Liguori/Della Forma's Letter, ''Antidumping Duty Review of Certain Pasta from Italy: Liguori's Case Brief,'' dated September 2, 2021; *see also* La Molisana's Letter, ''Certain Dry Pasta from Italy; A–475–818; Case Brief,'' dated September 2, 2021.

[3] *See* Memorandum, ''Certain Pasta from Italy: Issues and Decision Memorandum for the Final Results of Antidumping Duty Administrative Review; 2019–2020,'' dated concurrently with, and hereby adopted by, this notice (Issues and Decision Memorandum).

[4] *See, e.g., Ball Bearings and Parts Thereof from France, Germany, Italy, Japan, and the United Kingdom: Final Results of Antidumping Duty Administrative Reviews and Rescission of Reviews in Part,* 73 FR 52823, 52824 (September 11, 2008), and accompanying Issues and Decision Memorandum at Comment 16.

assessment rates by aggregating the total amount of dumping calculated for the examined sales of each importer and dividing each of these amounts by the total entered value associated with those sales. Where either a respondent's weighted-average dumping margin is zero or *de minimis* within the meaning of 19 CFR 351.106(c)(1), or an importer-specific assessment rate is zero or *de minimis,* we will instruct CBP to liquidate the appropriate entries without regard to antidumping duties.

For entries of subject merchandise during the POR produced by La Molisana or Liguori/Della Forma where the producer did not know its merchandise was destined for the United States we will instruct CBP to liquidate unreviewed suspended entries, consistent with the reseller policy, at the all-others rate if there is no rate for the intermediate company(ies) involved in the transaction.[5]

The assessment rate for antidumping duties for each of the companies not selected for individual examination, will be equal to the weighted-average dumping margin identified above in the Final Results of Review.

Commerce intends to issue assessment instructions to CBP no earlier than 35 days after the date of publication of the final results of this review in the **Federal Register**. If a timely summons is filed at the U.S. Court of International Trade, the assessment instructions will direct CBP not to liquidate relevant entries until the time for parties to file a request for a statutory injunction has expired (*i.e.,* within 90 days of publication).

Cash Deposit Requirements

The following cash deposit requirements will be effective for all shipments of the subject merchandise entered, or withdrawn from warehouse, for consumption on or after the publication date of the final results of this administrative review, as provided by section 751(a)(2)(C) of the Act: (1) The cash deposit rates for the companies identified above in the Final Results of Review will be equal to the company-specific weighted-average dumping margin established in the final results of this administrative review; (2) for merchandise exported by a company not covered in this administrative review but covered in a completed prior segment of the proceeding, the cash deposit rate will continue to be the company-specific rate published for the most recently completed segment of this proceeding; (3) if the exporter is not a firm covered in this review or completed prior segment of this proceeding but the producer is, the cash deposit rate will be the company-specific rate established for the most recently-completed segment of this proceeding for the producer of the subject merchandise; and (4) the cash deposit rate for all other producers or exporters will continue to be 15.45 percent, the all-others rate established in the section 129 determination.[6]

These cash deposit requirements, when imposed, shall remain in effect until further notice.

Notification to Importers

This notice serves as a final reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties and/or countervailing duties prior to liquidation of the relevant entries during this POR. Failure to comply with this requirement could result in Commerce's presumption that reimbursement of antidumping and/or countervailing duties has occurred and the subsequent assessment of double antidumping duties.

Administrative Protective Order

This notice also serves as a final reminder to parties subject to administrative protective order (APO) of their responsibility concerning the return or destruction of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3), which continues to govern business proprietary information in this segment of the proceeding. Timely written notification of the return or destruction of APO materials, or conversion to judicial protective order, is hereby requested. Failure to comply with the regulations and the terms of an APO is a sanctionable violation.

Notification to Interested Parties

We are issuing and publishing this notice in accordance with sections 751(a)(1) and 777(i)(1) of the Act, and 19 CFR 351.221(b)(5) and 19 CFR 351.213(h)(1).

Dated: November 8, 2021.

Ryan Majerus,

Deputy Assistant Secretary for Policy and Negotiations, performing the non-exclusive functions and duties of the Assistant Secretary for Enforcement and Compliance.

Appendix

List of Topics Discussed in the Issues and Decision Memorandum

I. Summary
II. Background
III. Scope of the Order
IV. Discussion of the Issues
  Comment 1: Liquidation Instructions for Liguori/Della Forma
  Comment 2: Bronze Die as a Physical Characteristic
  Comment 3: Application of the Cohen's *d* Test
V. Recommendation

[FR Doc. 2021–24821 Filed 11–12–21; 8:45 am]

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[5] For a full discussion of this practice, *see Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties,* 68 FR 23954 (May 6, 2003).

[6] *See Implementation of the Findings of the WTO Panel in US— Zeroing (EC): Notice of Determinations Under Section 129 of the Uruguay Round Agreements Act and Revocations and Partial Revocations of Certain Antidumping Duty Orders,* 72 FR 25261 (May 4, 2007).

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XB568]

Endangered and Threatened Species; Notice of Initiation of a 5-Year Review of the Common Angelshark (Squatina squatina)

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; request for information.

SUMMARY: NMFS announces the initiation of a 5-year review for the common angelshark (*Squatina squatina*). NMFS is required by the Endangered Species Act (ESA) to conduct 5-year reviews to ensure that the listing classifications of species are accurate. The 5-year review must be based on the best scientific and commercial data available at the time of the review; therefore, we request submission of any such information on the common angelshark that has become available since the species was listed in 2016.

DATES: To allow us adequate time to conduct this review, we must receive your information no later than January 14, 2022. While we continue to accept new information about any listed species at any time, information received after the date stated above may not be considered for purposes of this 5-year review.

ADDRESSES: You may submit information on this document, identified by NOAA–NMFS–2021–0118, by the following method:

Federal e-Rulemaking Portal: Go to *www.regulations.gov.* In the Search box, enter the above docket number for this notice. Then, click on the Search icon. On the resulting web page, click the ''Comment'' icon, complete the required fields, and enter or attach your comments.

Instructions: Comments sent by any other method, to any other address or individual, or received after the end of the specified period, may not be considered. All comments received are a part of the public record and will generally be posted for public viewing on *www.regulations.gov* without change. All personal identifying information (*e.g.,* name, address, etc.), confidential business information, or otherwise sensitive or protected information submitted voluntarily by the sender will be publicly accessible. NMFS will accept anonymous submissions (enter ''N/A'' in the required fields if you wish to remain anonymous).

FOR FURTHER INFORMATION CONTACT: Celeste Stout, Office of Protected Resources, (301) 427–8422, *Celeste.Stout@noaa.gov.*

SUPPLEMENTARY INFORMATION: This notice announces our review of the common angelshark (*Squatina squatina*) listed as endangered under the ESA. Section 4(c)(2)(A) of the ESA requires that we conduct a review of listed species at least once every 5 years. This will be the first review of this species since it was listed in 2016 (81 FR 50394, August 1, 2016). The regulations in 50 CFR 424.21 require that we publish a notice in the **Federal Register** announcing species currently under active review. On the basis of such reviews under section 4(c)(2)(B), we determine whether any species should be removed from the list (*i.e.,* delisted) or reclassified from endangered to threatened or from threatened to endangered (16 U.S.C. 1533(c)(2)(B)). As described by the regulations in 50 CFR 424.11(e), the Secretary shall delist a species if the Secretary finds that, after conducting a status review based on the best scientific and commercial data available: (1) The species is extinct; (2) the species does not meet the definition of an endangered species or a threatened species; and/or (3) the listed entity does not meet the statutory definition of a species. Any change in Federal classification would require a separate rulemaking process.

Background information on the species is available on the NMFS website at: *https://www.fisheries.noaa.gov/species/common-angelshark.*

Public Solicitation of New Information

To ensure that the reviews are complete and based on the best available scientific and commercial information, we are soliciting new information from the public, governmental agencies, Tribes, the scientific community, industry, environmental entities, and any other interested parties concerning the status of *Squatina squatina.* Categories of requested information include: (1) Species biology including, but not limited to, population trends, distribution, abundance, demographics, and genetics; (2) habitat conditions including, but not limited to, amount, distribution, and important features for conservation; (3) status and trends of threats to the species and its habitats; (4) conservation measures that have been implemented that benefit the species, including monitoring data demonstrating effectiveness of such measures; and (5) other new information, data, or corrections including, but not limited to, taxonomic or nomenclatural changes and improved analytical methods for evaluating extinction risk.

If you wish to provide information for the review, you may submit your information and materials electronically (see **ADDRESSES** section). We request that all information be accompanied by supporting documentation such as maps, bibliographic references, or reprints of pertinent publications. We also would appreciate the submitter's name, address, and any association, institution, or business that the person represents; however, anonymous submissions will also be accepted.

Authority: 16 U.S.C. 1531 *et seq.*

Dated: November 9, 2021.

Angela Somma,

Chief, Endangered Species Conservation Division, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2021–24863 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XB578]

North Pacific Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of public meetings.

SUMMARY: The North Pacific Fishery Management Council (Council) and its advisory committees will meet.

DATES: The meetings will be held from December 2, 2021 through December 16, 2021. See **SUPLEMENTARY INFORMATION** for specific dates and times.

ADDRESSES: The meetings will be by web conference. Join online through the links at *https://www.npfmc.org/upcoming-council-meetings.*

Council address: North Pacific Fishery Management Council, 1007 W 3rd Ave, Anchorage, AK 99501–2252; telephone: (907) 271–2809. Instructions for attending the meeting via web conference are given under Connection Information below.

FOR FURTHER INFORMATION CONTACT: Diana Evans, Council staff; email: *diana.evans@noaa.gov.* For technical support, please contact our administrative staff, email: *npfmc.admin@noaa.gov.*

SUPPLEMENTARY INFORMATION: The Council's Scientific and Statistical Committee (SSC) will begin at 8 a.m. on Thursday, December 2, 2021, through Friday, December 3, 2021, and on Monday, December 6, 2021, through Thursday, December 9, 2021. The Council's Advisory Panel (AP) will begin at 8 a.m. on Thursday, December 2, 2021, through Friday, December 3, 2021, and on Monday, December 6, 2021, through Thursday, December 9, 2021. The Council will meet on Wednesday, December 8, 2021, through Friday, December 10, 2021, and on Monday, December 13, 2021, through Thursday, December 16, 2021. All times listed are Alaska Time.

Agenda

Thursday, December 2, 2021, Through Friday, December 3, 2021; Monday, December 6, 2021, Through Thursday, December 9, 2021

The SSC agenda will include the following issues:

(1) BSAI (Bering Sea Aleutian Islands) Groundfish—Final harvest specifications; Joint and BSAI Plan Team reports; ecosystem status report

(2) GOA (Gulf of Alaska) Groundfish—Final harvest specifications; Plant Team report; ecosystem status report

The agenda is subject to change, and the latest version will be posted at *https://meetings.npfmc.org/Meeting/Details/2714* prior to the meeting, along with meeting materials.

In addition to providing ongoing scientific advice for fishery management decisions, the SSC functions as the

Council's primary peer review panel for scientific information, as described by the Magnuson-Stevens Act section 302(g)(1)(e), and the National Standard 2 guidelines (78 FR 43066). The peer-review process is also deemed to satisfy the requirements of the Information Quality Act, including the OMB Peer Review Bulletin guidelines.

Thursday, December 2, 2021, Through Friday, December 3, 2021; Monday, December 6, 2021, Through Thursday, December 9, 2021

The Advisory Panel agenda will include the following issues:

(1) Charter Halibut—2022 annual management measures, committee report
(2) BSAI Halibut abundance-based management (ABM)
(3) BSAI Groundfish—final harvest specifications; Joint and BSAI Plan Team reports; ecosystem status report
(4) GOA Groundfish—final harvest specifications; Plan Team reports; ecosystem status report
(5) Staff tasking

Wednesday, December 8, 2021, Through Friday, December 10, 2021; Monday, December 13, 2021, Through Thursday, December 16, 2021

The Council agenda will include the following issues. The Council may take appropriate action on any of the issues identified.

(1) All B Reports (Executive Director, NMFS Management, NOAA GC, NOAA Enforcement, ADF&G, USCG, USFWS)
(2) Charter Halibut—2022 annual management measures, committee report
(3) BSAI Halibut abundance-based management (ABM)—Final Action
(4) AP Report in full
(5) BSAI Groundfish—final harvest specifications; Joint and BSAI Plan Team reports; ecosystem status report
(6) GOA Groundfish—final harvest specifications; Plan Team reports; ecosystem status report
(7) D1 Red King Crab Savings Area Extension—Consideration of emergency action request
(8) Staff Tasking

Connection Information

You can attend the meeting online using a computer, tablet, or smartphone; or by telephone only. Connection information will be posted online at: *https://www.npfmc.org/upcoming-council-meetings.* For technical support, please contact our administrative staff, email: *npfmc.admin@noaa.gov.*

Public Comment

Public comment letters will be accepted and should be submitted electronically through the links at *https://www.npfmc.org/upcoming-council-meetings.* The Council strongly encourages written public comment for this meeting, to avoid any potential for technical difficulties to compromise oral testimony. The written comment period is open from November 15, 2021, to November 30, 2021, and closes at 5 p.m. Alaska Time on November 30th.

Although other non-emergency issues not on the agenda may come before this group for discussion, those issues may not be the subject of formal action during these meetings. Actions will be restricted to those issues specifically listed in this notice and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Fishery Conservation and Management Act, provided the public has been notified of the Council's intent to take final action to address the emergency.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: November 9, 2021.

Tracey L. Thompson,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2021–24846 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XB532]

South Atlantic Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of a public meeting.

SUMMARY: The South Atlantic Fishery Management Council (Council) will hold a webinar meeting of its Private Recreational Reporting Work Group evaluating reporting alternatives for the private recreational snapper grouper fishery.

DATES: The Workgroup meeting will be held from 1:30 p.m. until 4:30 p.m. on Wednesday, December 1, 2021.

ADDRESSES: *Meeting address:* The meeting will be held via webinar. Webinar registration is required. See **SUPPLEMENTARY INFORMATION**.

FOR FURTHER INFORMATION CONTACT: Kim Iverson, Public Information Officer, SAFMC; phone: (843) 302–8440 or toll free: (866) SAFMC–10; fax: (843) 769–4520; email: *kim.iverson@safmc.net.*

SUPPLEMENTARY INFORMATION: Meeting information, including the webinar link, agenda, and briefing book materials will be posted on the Council's website at: *https://safmc.net/safmc-meetings/other-meetings/.*

Agenda items include: A review of state and federal permitting requirements; discussion of census vs survey sampling approaches; a review of recent recreational data developments; a review the Council's recreational data needs and gaps; and identifying topics for the next meeting.

Although non-emergency issues not contained in this agenda may come before this group for discussion, those issues may not be the subject of formal action during this meeting. Action will be restricted to those issues specifically identified in this notice and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Fishery Conservation and Management Act, provided the public has been notified of the Council's intent to take final action to address the emergency.

Special Accommodations

The meeting is physically accessible to people with disabilities. Requests for auxiliary aids should be directed to the Council office (see **ADDRESSES**) at least 5 days prior to the meeting.

Note: The times and sequence specified in this agenda are subject to change.

Authority: 6 U.S.C. 1801 *et seq.*

Dated: November 9, 2021.

Tracey L. Thompson,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2021–24842 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XB574]

New England Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of public meeting.

SUMMARY: The New England Fishery Management Council (Council) is scheduling a public meeting of its

Groundfish Recreational Advisory Panel via webinar to consider actions affecting New England fisheries in the exclusive economic zone (EEZ). Recommendations from this group will be brought to the full Council for formal consideration and action, if appropriate.

DATES: This webinar will be held on Monday, November 29, 2021, at 9:30 a.m. Webinar registration URL information: *https://attendee.gotowebinar.com/register/4779175043487969040.*

ADDRESSES: *Council address:* New England Fishery Management Council, 50 Water Street, Mill 2, Newburyport, MA 01950.

FOR FURTHER INFORMATION CONTACT: Thomas A. Nies, Executive Director, New England Fishery Management Council; telephone: (978) 465–0492.

SUPPLEMENTARY INFORMATION:

Agenda

The Groundfish Recreational Advisory Panel will discuss draft alternatives and draft impacts analysis and make recommendations to the Groundfish Committee for Framework Adjustment 63 final action. The panel will make recommendations to the Committee, as appropriate, regarding possible 2022 Council priorities. Other business will be discussed, if necessary.

Although non-emergency issues not contained on the agenda may come before this Council for discussion, those issues may not be the subject of formal action during this meeting. Council action will be restricted to those issues specifically listed in this notice and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Act, provided the public has been notified of the Council's intent to take final action to address the emergency. The public also should be aware that the meeting will be recorded. Consistent with 16 U.S.C. 1852, a copy of the recording is available upon request.

Special Accommodations

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Thomas A. Nies, Executive Director, at (978) 465–0492, at least 5 days prior to the meeting date.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: November 9, 2021.

Tracey L. Thompson,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2021–24844 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XB561]

Mid-Atlantic Fishery Management Council (MAFMC); Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; public meeting.

SUMMARY: The Mid-Atlantic Fishery Management Council's Ecosystem and Ocean Planning Committee will hold a public meeting.

DATES: The meeting will be held on Monday, November 29, 2021, from 10 a.m. to 12 p.m. For agenda details, see **SUPPLEMENTARY INFORMATION**.

ADDRESSES: The meeting will be held via webinar. Connection information will be posted to the Council's calendar prior to the meeting at *www.mafmc.org.*

Council address: Mid-Atlantic Fishery Management Council, 800 N. State Street, Suite 201, Dover, DE 19901; telephone: (302) 674–2331; *www.mafmc.org.*

FOR FURTHER INFORMATION CONTACT: Christopher M. Moore, Ph.D., Executive Director, Mid-Atlantic Fishery Management Council, telephone: (302) 526–5255.

SUPPLEMENTARY INFORMATION: The Ecosystem and Ocean Planning Committee will meet to consider recommendations for revisions to the Mid-Atlantic Fishery Management Council's Policy on Offshore Wind Energy Development.

Special Accommodations

The meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Shelley Spedden, (302) 526–5251 at least 5 days prior to the meeting date.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: November 9, 2021.

Tracey L. Thompson,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2021–24843 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XB575]

North Pacific Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of web conference.

SUMMARY: The North Pacific Fishery Management Council (Council) Charter Halibut Management Committee will meet December 6, 2021.

DATES: The meeting will be held on Monday, December 6, 2021, from 8 a.m. to 4 p.m., Alaska Time.

ADDRESSES: The meeting will be a web conference. Join online through the link at *https://meetings.npfmc.org/Meeting/Details/2561.*

Council address: North Pacific Fishery Management Council, 1007 W 3rd Ave, Anchorage, AK 99501–2252; telephone: (907) 271–2809. Instructions for attending the meeting via video conference are given under **SUPPLEMENTARY INFORMATION**, below.

FOR FURTHER INFORMATION CONTACT: Sarah Marrinan, Council staff; phone; (907) 271–2809; email: *sarah.marrinan@noaa.gov.* For technical support please contact our admin Council staff, email: *npfmc.admin@noaa.gov.*

SUPPLEMENTARY INFORMATION:

Agenda

Monday, December 6, 2021

The Charter Halibut Management Committee will meet to discuss and recommend charter halibut management measures in International Pacific Halibut Commission (IPHC) Areas 2C and 3A for 2022. The Committee will first review the ADF&G analysis for projected charter removals for 2022 under different management scenarios to determine the measures that may be required to keep the charter halibut sector under its allocation. Since the allocations are set after the IPHC first determines the area apportionments for halibut, the Committee will indicate a range of preferred management measures contingent on where the charter halibut catch limit is set. The Committee will also discuss upcoming meetings and any other business. The agenda is subject to change, and the latest version will be posted at: *https://meetings.npfmc.org/Meeting/Details/2561* prior to the meeting, along with meeting materials.

Connection Information

You can attend the meeting online using a computer, tablet, or smart phone; or by phone only. Connection information will be posted online at: *https://meetings.npfmc.org/Meeting/Details/2561.*

Public Comment

Public comment letters will be accepted and should be submitted electronically to *https://meetings.npfmc.org/Meeting/Details/2561.*

Although other non-emergency issues not on the agenda may come before this group for discussion, those issues may not be the subject of formal action during this meeting. Actions will be restricted to those issues specifically listed in this notice and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Fishery Conservation and Management Act, provided the public has been notified of the Council's intent to take final action to address the emergency.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: November 9, 2021.

Tracey L. Thompson,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2021–24845 Filed 11–12–21; 8:45 am]

BILLING CODE 3510–22–P

CONSUMER PRODUCT SAFETY COMMISSION

Sunshine Act Meeting Notices

TIME AND DATE: Wednesday, November 17, 2021, 10:00 a.m.–11:00 a.m.

PLACE: This meeting will be held remotely.

STATUS: Commission Meeting—Open to the Public.

MATTERS TO BE CONSIDERED: Briefing Matter.

Proposed Rule: Safety Standard for Magnets.

All attendees and participants should pre-register for the Commission meeting (Webinar). To pre-register for the Webinar, please visit *https://attendee.gotowebinar.com/register/3338735646402245132* and fill in the information. After registering you will receive a confirmation email containing information about joining the webinar.

TIME AND DATE: Thursday, November 18, 2021; 10:00 a.m.–11:00 a.m.

PLACE: This meeting will be held remotely.

STATUS: Commission Meeting—Open to the Public.

MATTERS TO BE CONSIDERED: Briefing Matter.

Notices of Proposed Rulemaking to (1) Add Window Covering Cords to the Substantial Product Hazard List, and (2) Establish a Safety Standard for Operating Cords on Custom Window Coverings.

All attendees and participants should pre-register for the Commission Meeting (Webinar). To pre-register for the Webinar, please visit *https://attendee.gotowebinar.com/register/8154835170084361484* and fill in the information. After registering you will receive a confirmation email containing information about joining the webinar.

TIME AND DATE: Wednesday, December 1, 2021; 10:00 a.m.–11:00 a.m.

PLACE: This meeting will be held remotely.

STATUS: Commission Meeting—Open to the Public.

MATTERS TO BE CONSIDERED: Briefing Matter.

Final Rule: Safety Standard for Crib Mattresses.

All attendees and participants should pre-register for the Commission Meeting (Webinar). To pre-register for the Webinar, please visit *https://attendee.gotowebinar.com/register/1901446349992111372* and fill in the information. After registering you will receive a confirmation email containing information about joining the webinar.

TIME AND DATE: Thursday, December 2, 2021; 10:00 a.m.–11:00 a.m.

PLACE: This meeting will be held remotely.

STATUS: Commission Meeting—Open to the Public.

MATTERS TO BE CONSIDERED: Briefing Matter.

Proposed Safety Standard for Clothing Storage Units.

All attendees and participants should pre-register for the Commission Meeting (Webinar). To pre-register for the Webinar, please visit *https://attendee.gotowebinar.com/register/1633968156303028748* and fill in the information. After registering you will receive a confirmation email containing information about joining the webinar.

CONTACT PERSON FOR MORE INFORMATION: Alberta E. Mills, Office of the Secretary, U.S. Consumer Product Safety Commission, 4330 East West Highway, Bethesda, MD 20814, 301–504–7479 (Office) or 240–863–8938 (Cell).

Dated: November 9, 2021.

Alberta E. Mills,

Commission Secretary.

[FR Doc. 2021–24917 Filed 11–10–21; 11:15 am]

BILLING CODE 6355–01–P

U.S. INTERNATIONAL DEVELOPMENT FINANCE CORPORATION

Privacy Act of 1974; System of Records

AGENCY: U.S. International Development Finance Corporation.

ACTION: Notice of a new system of records.

SUMMARY: In accordance with the Privacy Act of 1974, the U.S. International Development Finance Corporation (DFC) proposes to establish a new system of records titled, ''DFC/09 Reasonable Accommodations Records.'' This system of records will include information that DFC collects and maintains from those who request and/or receive reasonable accommodations from DFC for medical or religious reasons.

DATES: Submit comments on or before December 15, 2021. This new system is effective upon publication in the **Federal Register**, except for the routine uses, which are effective December 20, 2021.

ADDRESSES: You may submit written comments through the following methods:

- *Mail:* Tina Donbeck, Chief Information Officer, U.S. International Development Finance Corporation, 1100 New York Avenue NW, Washington, DC 20527.
- *Email: fedreg@dfc.gov.*

All submissions received must reference ''DFC/09 Reasonable Accommodation SORN.''

Please note that all written comments received in response to this notice will be considered public records.

FOR FURTHER INFORMATION CONTACT: Tina Donbeck, Chief Information Officer and Senior Agency Official for Privacy at *SAOP@dfc.gov* or (202) 336–8400. Please put ''Reasonable Accommodations SORN'' in the subject line of your email.

SUPPLEMENTARY INFORMATION: In accordance with the Privacy Act of 1974, the U.S. International Development Finance Corporation (DFC) proposes to establish a new system of records titled, ''DFC/09 Reasonable Accommodations Records.'' This system of records covers DFC's collection and maintenance of records on applicants for employment, employees, and other individuals who participate in DFC programs or activities who request or receive reasonable accommodations or other appropriate modifications from DFC for medical or religious reasons.

Title V of the Rehabilitation Act of 1973, as amended, prohibits

discrimination in services and employment on the basis of disability, and Title VII of the Civil Rights Act of 1974 prohibits discrimination, including on the basis of religion. These prohibitions on discrimination require Federal agencies to provide reasonable accommodations to individuals with disabilities and those with sincerely held religious beliefs unless doing so would impose an undue hardship. In some instances, individuals may request modifications to their workspace, schedule, duties, or other requirements for documented medical reasons that may not qualify as a disability but may necessitate an appropriate modification to workplace policies and practices. DFC may address those requests pursuant to the general authority of the Director contained in Title V of the United States Code.

Reasonable accommodations may include, but are not limited to: Making existing facilities readily accessible to individuals with disabilities; restructuring jobs, modifying work schedules or places of work, and providing flexible scheduling for medical appointments or religious observance; acquiring or modifying equipment or examinations or training materials; providing qualified readers and interpreters, personal assistants, service animals; granting permission to wear religious dress, hairstyles, or facial hair or to observe a religious prohibition against wearing certain garments; considering requests for medical and religious exemptions to specific workplace requirements; and making other modifications to workplace policies and practices.

DFC's Office of Human Resources Management and DFC's Office of Equal Employment Opportunity process requests for reasonable accommodations due to a medical or religious reason; DFC's Office of Human Resources Management also processes requests based on documented medical reasons that may not qualify as a disability but that necessitate an appropriate modification to workplace policies and practices. Other DFC offices may also receive such requests related to programs or activities for which they are responsible. The request, documentation provided in support of the request, any evaluation conducted internally, or by a third party under contract to DFC, the decision regarding whether to grant or deny a request, and the details and conditions of the reasonable accommodation are all included in this system of records.

DFC has provided a report of this system of records to the Committee on Oversight and Government Reform of the House of Representatives, the Committee on Homeland Security and Governmental Affairs of the Senate, and the Office of Management and Budget (OMB), pursuant to 5 U.S.C. 552a(r) and OMB Circular A–108, ''Federal Agency Responsibilities for Review, Reporting, and Publication under the Privacy Act,'' dated December 23, 2016. This system will be included in the DFC inventory of record systems.

U.S. International Development Finance Corporation.

Nichole Skoyles,

Administrative Counsel.

SYSTEM NAME AND NUMBER:

U.S. International Development Finance Corporation, DFC/09 Reasonable Accommodations Records

SECURITY CLASSIFICATION:

Unclassified.

SYSTEM LOCATION:

Records are maintained primarily by the U.S. International Development Finance Corporation's Office of Human Resources Management and Office of Equal Employment Opportunity, 1100 New York Avenue NW, Washington DC 20527. Records may also be also be kept in the department of the requesting individual. Records may be located in locked cabinets and offices, on DFC's local area network, or in designated U.S. data centers for FedRAMP-authorized cloud service providers.

SYSTEM MANAGER(S):

Vice President and Chief Human Capital Officer, U.S. International Development Finance Corporation, 1100 New York Avenue NW, Washington, DC 20527, *RAC@dfc.gov.*

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

The Rehabilitation Act of 1973, 29 U.S.C. 701, 791, 794; Title VII of the Civil Rights Act of 1964, 42 U.S.C. 2000e; 29 CFR 1605 (Guidelines on Discrimination Because of Religion); 29 CFR 1614 (Federal Sector Equal Employment Opportunity); 29 CFR 1614 (Regulations to Implement the Equal Employment Provisions of the Americans With Disabilities Act); 5 U.S.C. 302, 1103; Executive Order 13164, Requiring Federal Agencies to Establish Procedures to Facilitate the Provision of Reasonable Accommodation (July 26, 2000); and Executive Order 13548, Increasing Federal Employment of Individuals with Disabilities (July 26, 2010).

PURPOSE(S) OF THE SYSTEM:

The purpose of this system of records is to allow DFC to collect and maintain records on applicants for employment, employees, and other individuals who participate in DFC programs or activities who request or receive reasonable accommodations or other appropriate modifications from DFC for medical or religious reasons; to process, evaluate, and make decisions on individual requests; and to track and report the processing of such requests DFC-wide to comply with applicable requirements in law and policy.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Applicants for Federal employment, Federal employees, contractors, detailees, volunteers, visitors, and other individuals who participate in DFC programs or activities who requested and/or received reasonable accommodations or other appropriate modifications from DFC for medical or religious reasons.

CATEGORIES OF RECORDS IN THE SYSTEM:

- Requester's name;
- Requester's status (applicant or current employee, etc.);
- Date of request;
- Employee's position title, grade, series, step;
- Position title, grade, series, step of the position the requester is applying for;
- Requester's contact information (addresses, phone numbers, and email addresses);
- Description of the requester's medical condition or disability and any medical documentation provided in support of the request;
- Requester's statement of a sincerely held religious belief and any additional information provided concerning that religious belief and the need for an accommodation to exercise that belief;
- Description of the accommodation being requested;
- Description of previous requests for accommodation;
- Whether the request was made orally or in writing;
- Documentation by a DFC official concerning whether the disability is obvious, and the accommodation is obvious and uncomplicated, whether medical documentation is required to evaluate the request, whether research is necessary regarding possible accommodations, and any extenuating circumstances that prevent the DFC official from meeting the relevant timeframe;
- Whether the request for reasonable accommodation was granted or denied, and if denied the reason for the denial;
- The amount of time taken to process the request;

- The sources of technical assistance consulted in trying to identify a possible reasonable accommodation;
- Any reports or evaluations prepared in determining whether to grant or deny the request; and
- Any other information collected or developed in connection with the request for a reasonable accommodation.

RECORD SOURCE CATEGORIES:

Information is obtained from the individuals who request and/or receive a reasonable accommodation or other appropriate modification from DFC, or their authorized representative; directly or indirectly from an individual's medical provider or another medical professional who evaluates the request; directly or indirectly from an individual's religious or spiritual advisors or institutions; and from management officials, including supervisors, the Office of Information Technology, and the Facilities, Travel & Security Division.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND PURPOSES OF SUCH USES:

In addition to those disclosures generally permitted under 5 U.S.C. 552a(b) of the Privacy Act, all or a portion of the records or information contained in this system may be disclosed outside DFC as a routine use pursuant to 5 U.S.C. 552a(b)(3) as follows:

a. To the Department of Justice, including Offices of the U.S. Attorneys; another Federal agency conducting litigation or in proceedings before any court, adjudicative, or administrative body; another party in litigation before a court, adjudicative, or administrative body; or to a court, adjudicative, or administrative body. Such disclosure is permitted only when it is relevant or necessary to the litigation or proceeding, and one of the following is a party to the litigation or has an interest in such litigation:

(1) DFC, or any component thereof;

(2) Any employee or former employee of DFC in his or her official capacity;

(3) Any employee or former employee of DFC in his or her capacity where the Department of Justice or DFC has agreed to represent the employee;

(4) The United States, a Federal agency, or another party in litigation before a court, adjudicative, or administrative body, upon the DFC General Counsel's approval, pursuant to 5 CFR part 295 or otherwise.

b. To the appropriate Federal, State, or local agency responsible for investigating, prosecuting, enforcing, or implementing a statute, rule, regulation, or order, when a record, either on its face or in conjunction with other information, indicates or is relevant to a violation or potential violation of civil or criminal law or regulation.

c. To a member of Congress from the record of an individual in response to an inquiry made at the request of the individual to whom the record pertains.

d. To the National Archives and Records Administration (NARA) for records management inspections being conducted under the authority of 44 U.S.C. 2904 and 2906.

e. To appropriate agencies, entities, and persons when (1) DFC suspects or has confirmed that there has been a breach of the system of records; (2) DFC has determined that as a result of the suspected or confirmed breach, there is a risk of harm to individuals, DFC (including its information systems, programs, and operations), the Federal Government, or national security; and (3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with DFC's efforts to respond to the suspected or confirmed breach or to prevent, minimize, or remedy such harm.

f. To another Federal agency or Federal entity, when DFC determines that information from this system of records is reasonably necessary to assist the recipient agency or entity in (1) responding to a suspected or confirmed breach or (2) preventing, minimizing, or remedying the risk of harm to individuals, the recipient agency or entity (including its information systems, programs, and operations), the Federal Government, or national security, resulting from a suspected or confirmed breach.

g. To contractors, grantees, experts, consultants, or volunteers performing or working on a contract, service, grant, cooperative agreement, or other assignment for DFC when DFC determines that it is necessary to accomplish an agency function related to this system of records. Individuals provided information under this routine use are subject to the same Privacy Act requirements and limitations on disclosure as are applicable to DFC employees.

h. To another federal agency or commission with responsibility for labor or employment relations or other issues, including equal employment opportunity and reasonable accommodation issues, when that agency or commission has jurisdiction over reasonable accommodation.

i. To an authorized appeal grievance examiner, formal complaints examiner, administrative judge, equal employment opportunity investigator, arbitrator, or other duly authorized official engages in investigation or settlement of a grievance, complaint, or appeal filed by an individual who requested a reasonable accommodation or other appropriate modification.

j. To another Federal agency, including but not limited to the Equal Employment Opportunity Commission and the Office of Special Counsel to obtain advice regarding statutory, regulatory, policy, and other requirements related to reasonable accommodation.

k. To a Federal agency or entity authorized to procure assistive technologies and services in response to a request for reasonable accommodation.

l. To first aid and safety personnel if the individual's medical condition requires emergency treatment.

m. To another Federal agency or oversight body charged with evaluating DFC's compliance with the laws, regulations, and policies governing reasonable accommodation requests.

n. To another Federal agency pursuant to a written agreement with DFC to provide services (such as medical evaluations), when necessary, in support of reasonable accommodation decisions.

POLICIES AND PRACTICES FOR STORAGE OF RECORDS:

The records in this system of records are stored electronically on DFC's local area network or within a FedRAMP-authorized cloud service providers segregated from non-government traffic and data, with access limited to a small number of personnel. In addition, paper records are stored in locked file cabinets in access-restricted offices.

POLICIES AND PRACTICES FOR RETRIEVAL OF RECORDS:

Records may be retrieved by name or other unique personal identifiers.

POLICIES AND PRACTICES FOR RETENTION AND DISPOSAL OF RECORDS:

Records in this system of records are maintained in accordance with GRS 2.3 and are destroyed three years after separation from the agency or all appeals are concluded, whichever is later, but longer retention is authorized if requested for business use.

ADMINISTRATIVE, TECHNICAL, AND PHYSICAL SAFEGUARDS:

Records in the system are protected from unauthorized access and misuse through various administrative, technical, and physical security measures. DFC security measures are in

compliance with the Federal Information Security Modernization Act (Pub. L.113–283), associated Office of Management and Budget policies, and applicable standards and guidance from the National Institute of Standards and Technology. Strict controls have been imposed to minimize the risk of compromising the information that is stored. Access to the paper and electronic records in this system of records is limited to those individuals who have a need to know the information for the performance of their official duties and who have appropriate clearances or permissions.

RECORDS ACCESS PROCEDURES:

Individuals seeking notification of and access to their records in this system of records may submit a request in writing to the System Manager listed above. Requests for amendments to records and requests for review of a refusal to amend a record must comply with the requirements of 22 CFR 707.23.

CONTESTING RECORD PROCEDURES:

Individuals wishing to request amendment of records about them contained in this system of records may do so by writing to the System Manager above. Requests for amendments to records and requests for review of a refusal to amend a record must comply with the requirements of 22 CFR 707.23.

NOTIFICATION PROCEDURES:

See ''Record Access Procedure.''

EXEMPTIONS PROMULGATED FOR THE SYSTEM:

None.

HISTORY:

None.

[FR Doc. 2021–24802 Filed 11–12–21; 8:45 am]

BILLING CODE 3210–01–P

DEPARTMENT OF DEFENSE

Department of the Air Force

[Docket ID: USAF–2021–HQ–0007]

Submission for OMB Review; Comment Request

AGENCY: Department of the Air Force, Department of Defense (DoD).

ACTION: 30-Day information collection notice.

SUMMARY: The DoD has submitted to OMB for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act.

DATES: Consideration will be given to all comments received by December 15, 2021.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

FOR FURTHER INFORMATION CONTACT: Angela Duncan, 571–372–7574, or *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: Air Force Family Integrated Results & Statistical Tracking Automated System; OMB Control Number 0701–0070.

Type of Request: Regular.

Number of Respondents: 37,500.

Responses per Respondent: 1.

Annual Responses: 37,500.

Average Burden per Response: 15 minutes.

Annual Burden Hours: 9,375 hours.

Needs and Uses: The information collection requirement is necessary to record demographic information on Airman & Family Readiness Center (A&FRC) customers, results of the customer's visits, determine customer needs, service plan, referrals, workshop attendance and other related A&FRC activities and services accessed by the customer. Data is used to determine the effectiveness of A&FRC activities and services (results management) as well as collect and provide return on investment data to leadership. Information is compiled for statistical reporting to military bases, major commands, Headquarters United States Air Force, Department of Defense and Congress.

Affected Public: Individuals or households.

Frequency: On occasion.

Respondent's Obligation: Voluntary.

OMB Desk Officer: Ms. Jasmeet Seehra.

You may also submit comments and recommendations, identified by Docket ID number and title, by the following method:

• *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

Instructions: All submissions received must include the agency name, Docket ID number, and title for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

DOD Clearance Officer: Ms. Angela Duncan.

Requests for copies of the information collection proposal should be sent to Ms. Duncan at *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

Dated: November 8, 2021.

Aaron T. Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2021–24798 Filed 11–12–21; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Department of the Army

Program Comment Plan for Army Vietnam War Era Historic Housing, Associated Buildings and Structures, and Landscape Features (1963–1975)

AGENCY: Department of the Army, DoD.

ACTION: Notice of Availability (NOA).

SUMMARY: The Department of the Army (Army) is making its *Program Comment Plan for Army Vietnam War Era Historic Housing, Associated Buildings and Structures, and Landscape Features (1963–1975)* (Army Program Comment Plan) available for public review. The Army Program Comment Plan is located on the Army's website: *https://www.denix.osd.mil/Army-vwehh-pc* under ''Administrative Documents.''

DATES: Consideration will be given to all comments on the Army Program Comment Plan that are received within 30 days from the date of this Notice of Availability.

ADDRESSES: You may submit written comments identified by ''Army Program Comment Plan'' to: Office of the Assistant Secretary of the Army for Installations, Energy and Environment, ATTN: DASA–ESOH (Dr. David Guldenzopf), 110 Army Pentagon, Room 3E464, Washington, DC 20310–1001, or by email to *david.b.guldenzopf.civ@army.mil.*

FOR FURTHER INFORMATION CONTACT: Dr. David Guldenzopf, Department of the Army Federal Preservation Officer at *david.b.guldenzopf.civ@army.mil,* or (703) 459–7756.

SUPPLEMENTARY INFORMATION: This notice of availability for public review of the Army Program Comment Plan initiates the Army's public participation requirements under 36 CFR 800.14(e)(2) for the Army's proposed *Program Comment for Army Vietnam War Era Historic Housing, Associated Buildings*

and Structures, and Landscape Features (1963–1975). On 8 October 2021, the Department of the Army notified the Advisory Council on Historic Preservation (ACHP) of the Army's intent to request a Program Comment for Army Vietnam War Era Historic Housing, Associated Buildings and Structures, and Landscape Features (1963–1975) in accordance with the National Historic Preservation Act (NHPA) 54 U.S.C. 306108, and 36 CFR 800.14 (e). The goal of the Program Comment is to provide the Army with National Historic Preservation Act (NHPA) 54 U.S.C. 306108 compliance for the repetitive management actions occurring on this large inventory of similar property types by means of the procedures in 36 CFR 800.14(e), in lieu of conducting individual projects reviews under 36 CFR 800.3 through 800.7.

James W. Satterwhite, Jr.,

Army Federal Register Liaison Officer.

[FR Doc. 2021–24720 Filed 11–12–21; 8:45 am]

BILLING CODE 5061–AP–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2021–OS–0115]

Proposed Collection; Comment Request

AGENCY: The Office of the Under Secretary of Defense for Personnel and Readiness, Department of Defense (DoD).

ACTION: Information collection notice.

SUMMARY: In compliance with the *Paperwork Reduction Act of 1995,* the Office of the Under Secretary of Defense for Personnel and Readiness announces a proposed public information collection and seeks public comment on the provisions thereof. Comments are invited on: Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; the accuracy of the agency's estimate of the burden of the proposed information collection; ways to enhance the quality, utility, and clarity of the information to be collected; and ways to minimize the burden of the information collection on respondents, including through the use of automated collection techniques or other forms of information technology.

DATES: Consideration will be given to all comments received by January 14, 2022.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods:

Federal eRulemaking Portal: http://www.regulations.gov. Follow the instructions for submitting comments.

Mail: DoD cannot receive written comments at this time due to the COVID–19 pandemic. Comments should be sent electronically to the docket listed above.

Instructions: All submissions received must include the agency name, docket number and title for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: To request more information on this proposed information collection or to obtain a copy of the proposal and associated collection instruments, please write to Defense Human Resources Activity, 4800 Mark Center Drive, Suite 08F05 Alexandria, VA 22350, LaTarsha Yeargins, 571–372–2089.

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: Defense Sexual Assault Incident Reporting; DD Form 2965, 2910, 2910–1, 2910–2; OMB Control Number 0704–0482.

Needs and Uses: Section 563 of Public Law (Pub. L.) 110–417, the National Defense Authorization Act (NDAA) for Fiscal Year (FY) 2009, directs the Secretary of Defense to implement a centralized case-level database for the collection and maintenance of information regarding sexual assaults involving members of the Armed Forces. This includes information, if available, about the nature of the assault, victim, alleged offender, investigative information, case outcomes in connection with the assault, and other information necessary to fulfill reporting requirements. Section 543 of Public Law 114–328, the NDAA for FY2017, further directed the Secretary of Defense to include information on each claim of retaliation in connection with a report of sexual assault in the Armed Force made by or against a member of such Armed Force in the Annual Report on Sexual Assault in the Military. This includes the narrative description and nature of each complaint, information on the complainant and alleged retaliator, and summary and determination of the investigation. Section 536 of Public Law 116–92 of the National Defense Authorization Act for Fiscal Year 2020 directs the Secretary to prescribe procedures under which a victim who files a restricted report on an incident of sexual assault may request, at any time, the return of any personal property of the victim obtained as part of the sexual assault forensic examination.

Affected Public: Individuals or households.

Annual Burden Hours: 16,371.68 hours.

Number of Respondents: 7,871.

Responses per Respondent: 1.

Annual Responses: 7,871.

Average Burden per Response: 2.08 hours.

Frequency: On occasion.

Dated: November 8, 2021.

Aaron T. Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2021–24797 Filed 11–12–21; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2021–OS–0116]

Proposed Collection; Comment Request

AGENCY: Defense Counterintelligence and Security Agency (DCSA), Department of Defense (DoD).

ACTION: Information collection notice.

SUMMARY: In compliance with the *Paperwork Reduction Act of 1995,* the Defense Counterintelligence and Security Agency announces a proposed public information collection and seeks public comment on the provisions thereof. Comments are invited on: Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; the accuracy of the agency's estimate of the burden of the proposed information collection; ways to enhance the quality, utility, and clarity of the information to be collected; and ways to minimize the burden of the information collection on respondents, including through the use of automated collection techniques or other forms of information technology.

DATES: Consideration will be given to all comments received by January 14, 2022.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods:

Federal eRulemaking Portal: http://www.regulations.gov. Follow the instructions for submitting comments.

Mail: DoD cannot receive written comments at this time due to the COVID–19 pandemic. Comments should be sent electronically to the docket listed above.

Instructions: All submissions received must include the agency name, docket number and title for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: To request more information on this proposed information collection or to obtain a copy of the proposal and associated collection instruments, please write to Defense Counterintelligence and Security Agency; 27130 Telegraph Road, Quantico, VA 22134; ATTN: Ms. Eleanor Rempfer or call (571) 305–6392.

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: National Industrial Security System (NISS); DCSA Form 147; OMB Control Number 0705–0006.

Needs and Uses: The information collection requirement is necessary for DCSA to oversee the National Industrial Security Program (NISP) pursuant to Executive Order 12829. The National Industrial Security System (NISS) is the primary collection instrument for DCSA oversight of the NISP and maintaining data associated with cleared facilities and their oversight. The NISS is the repository of records related to the maintenance of information pertaining to contractor facility security clearances (FCL) and contractor capabilities to protect classified information in its possession. The information is utilized to determine if a company and its key management personnel are eligible for issuance of a facility clearance in accordance with NISPOM requirements. In addition, information is utilized to inform Government Contracting Activities of contractor's ability to maintain facility clearance status and/or storage capability as well as to analyze vulnerabilities identified within security programs and ensure proper mitigation actions are taken to preclude unauthorized disclosure of classified information. As part of the FCL process, contractors must also complete and maintain a DCSA Form 147 in NISS. The form provides a single document to record the numerous characteristics of Open Storage Areas that are required to be reviewed for contractor facilities to be approved by DCSA for classified storage.

Affected Public: Business or other for-profit; not-for-profit institutions.

Annual Burden Hours: 23,342.

Number of Respondents: 11,671.

Responses per Respondent: 2.

Annual Responses: 23,342.

Average Burden per Response: 1 hour.

Frequency: As required.

Dated: November 8, 2021.

Aaron T. Siegel,

Alternate OSD Federal Register, Liaison Officer, Department of Defense.

[FR Doc. 2021–24799 Filed 11–12–21; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2021–OS–0094]

Submission for OMB Review; Comment Request

AGENCY: The Office of the Under Secretary of Defense for Personnel and Readiness, Department of Defense (DoD).

ACTION: 30-day information collection notice.

SUMMARY: The DoD has submitted to OMB for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act.

DATES: Consideration will be given to all comments received by December 15, 2021.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

FOR FURTHER INFORMATION CONTACT: Angela Duncan, 571–372–7574, or *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

SUPPLEMENTARY INFORMATION:

Title; Associated form; and OMB Number: DoD Educational Loan Repayment Program (LRP) Application; DD Form 2475; OMB Control Number 0704–0152.

Type of Request: Extension.

Number of Respondents: 44,000.

Responses per Respondent: 1.

Annual Responses: 44,000.

Average Burden per Response: 10 minutes.

Annual Burden Hours: 7,333 hours.

Needs and Uses: The information collection requirement is necessary for Military Services to pay a portion of Service member student loan(s). The information provided is reviewed by Military Service personnel record custodians to verify that the Service member meets eligibility requirements. This form will then be forwarded to the lender the Service member identifies for verification of the loan amount and status. The form is returned to the Service finance office to make the annual payment to the Service member's lender. Collected information is covered by the applicable military Service System of Records Notice for the Official Military Personnel File of Military Records Jacket.

Affected Public: Individuals or households.

Frequency: On occasion.

Respondent's Obligation: Voluntary.

OMB Desk Officer: Ms. Jasmeet Seehra.

You may also submit comments and recommendations, identified by Docket ID number and title, by the following method:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

Instructions: All submissions received must include the agency name, Docket ID number, and title for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

DOD Clearance Officer: Ms. Angela Duncan.

Requests for copies of the information collection proposal should be sent to Ms. Duncan at *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

Dated: November 8, 2021.

Aaron T. Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2021–24801 Filed 11–12–21; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2021–OS–0099]

Submission for OMB Review; Comment Request

AGENCY: Under Secretary of Defense for Acquisition and Sustainment, Department of Defense (DoD).

ACTION: 30-Day information collection notice.

SUMMARY: The DoD has submitted to OMB for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act.

DATES: Consideration will be given to all comments received by December 15, 2021.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

FOR FURTHER INFORMATION CONTACT: Angela Duncan, 571–372–7574, or *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: Procurement Technical Assistance Center Cooperative Agreement Performance Report; DLA Form 1806; OMB Control Number 0704–0320.

Type of Request: Extension.

Number of Respondents: 95.

Responses per Respondent: 4.

Annual Responses: 380.

Average Burden per Response: 5 hours.

Annual Burden Hours: 1,900.

Needs and Uses: This information collection by the Defense Logistics Agency (DLA) gathers data to be used in measuring, on a quarterly basis, cooperative agreement recipients' performance against goals and objectives established by awards. The Department of Defense (DoD) Procurement Technical Assistance (PTA) Cooperative Agreement Program was established by Congress in 1985 to assist state and local governments, tribal organizations, tribal economic enterprises, and other non-profit entities in establishing or maintaining PTA activities to help business firms market their goods and services to the DoD, other federal agencies, and state and local governments. Administrative requirements for the program are established by the DoD Grant and Agreement Regulations.

Affected Public: State, local, or tribal government; not-for-profit institutions.

Frequency: Quarterly.

Respondent's Obligation: Required to obtain or retain benefits.

OMB Desk Officer: Ms. Jasmeet Seehra.

You may also submit comments and recommendations, identified by Docket ID number and title, by the following method:

• *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

Instructions: All submissions received must include the agency name, Docket ID number, and title for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

DOD Clearance Officer: Ms. Angela Duncan.

Requests for copies of the information collection proposal should be sent to Ms. Duncan at *whs.mc-alex.esd.mbx.dd-dod-information-collections@mail.mil.*

Dated: November 8, 2021.

Aaron T. Siegel,

Alternate OSD Federal Register, Liaison Officer, Department of Defense.

[FR Doc. 2021–24803 Filed 11–12–21; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Department of the Navy

[Docket ID: USN–2021–HQ–0010]

Proposed Collection; Comment Request

AGENCY: The Office of the Assistant Secretary of the Navy, Department of Defense (DoD).

ACTION: Information collection notice.

SUMMARY: In compliance with the *Paperwork Reduction Act of 1995,* the Office of Civilian Human Resources announces a proposed public information collection and seeks public comment on the provisions thereof. Comments are invited on: Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; the accuracy of the agency's estimate of the burden of the proposed information collection; ways to enhance the quality, utility, and clarity of the information to be collected; and ways to minimize the burden of the information collection on respondents, including through the use of automated collection techniques or other forms of information technology.

DATES: Consideration will be given to all comments received by January 14, 2022.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods:

Federal eRulemaking Portal: http://www.regulations.gov. Follow the instructions for submitting comments.

Mail: DoD cannot receive written comments at this time due to the COVID–19 pandemic. Comments should be sent electronically to the docket listed above.

Instructions: All submissions received must include the agency name, docket number and title for this **Federal Register** document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing on the internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: To request more information on this proposed information collection or to obtain a copy of the proposal and associated collection instruments, please write to the Office of the Department of the Navy Information Management Control Officer, 2000 Navy Pentagon, Rm. 4E563, Washington, DC 20350, Ms. Ashley John or call 703–614–7583.

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: Department of the Navy (DON).

Reasonable Accommodations (RA) Tracker; SECNAV Form 12306/1T Confirmation of Reasonable Accommodation Request; OMB Control Number 0703–0063.

Needs and Uses: The information collection requirement is necessary to track, monitor, review, and process requests for reasonable accommodations applicants for employment. This information will be collected by DON Equal Employment Opportunity personnel involved in the Reasonable Accommodation process and data input into the Reasonable Accommodation Tracker (electronic information system) pursuant to Executive Order 13163. Official Reasonable Accommodation

case files are secured with access granted on a strictly limited basis.

Affected Public: Individuals or households.

Annual Burden Hours: 33 hours.

Number of Respondents: 100.

Responses per Respondent: 1.

Annual Responses: 100.

Average Burden per Response: 20 minutes.

Frequency: On occasion.

Dated: November 8, 2021.

Aaron T. Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2021–24796 Filed 11–12–21; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2021–SCC–0159]

Agency Information Collection Activities; Comment Request; EDFacts Data Collection School Years 2022–23, 2023–24, and 2024–25 (With 2021–22 Continuation)

AGENCY: Institute of Educational Science (IES), Department of Education (ED).

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, ED is proposing a revision of a currently approved collection.

DATES: Interested persons are invited to submit comments on or before January 14, 2022.

ADDRESSES: To access and review all the documents related to the information collection listed in this notice, please use *http://www.regulations.gov* by searching the Docket ID number ED–2021–SCC–0159. Comments submitted in response to this notice should be submitted electronically through the Federal eRulemaking Portal at *http://www.regulations.gov* by selecting the Docket ID number or via postal mail, commercial delivery, or hand delivery. If the *regulations.gov* site is not available to the public for any reason, ED will temporarily accept comments at *ICDocketMgr@ed.gov.* Please include the docket ID number and the title of the information collection request when requesting documents or submitting comments. *Please note that comments submitted by fax or email and those submitted after the comment period will not be accepted.* Written requests for information or comments submitted by postal mail or delivery should be addressed to the PRA Coordinator of the Strategic Collections and Clearance Governance and Strategy Division, U.S. Department of Education, 400 Maryland Ave. SW, LBJ, Room 6W208B, Washington, DC 20202–8240.

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Carrie Clarady, 202–245–6347.

SUPPLEMENTARY INFORMATION: The Department of Education (ED), in accordance with the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3506(c)(2)(A)), provides the general public and Federal agencies with an opportunity to comment on proposed, revised, and continuing collections of information. This helps the Department assess the impact of its information collection requirements and minimize the public's reporting burden. It also helps the public understand the Department's information collection requirements and provide the requested data in the desired format. ED is soliciting comments on the proposed information collection request (ICR) that is described below. The Department of Education is especially interested in public comment addressing the following issues: (1) Is this collection necessary to the proper functions of the Department; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the Department enhance the quality, utility, and clarity of the information to be collected; and (5) how might the Department minimize the burden of this collection on the respondents, including through the use of information technology. Please note that written comments received in response to this notice will be considered public records.

Title of Collection: EDFacts Data Collection School Years 2022–23, 2023–24, and 2024–25 (With 2021–22 Continuation).

OMB Control Number: 1850–0925.

Type of Review: A revision of a currently approved information collection.

Respondents/Affected Public: State, Local, and Tribal Governments.

Total Estimated Number of Annual Responses: 61.

Total Estimated Number of Annual Burden Hours: 126,880.

Abstract: EDFacts is a U.S. Department of Education (ED) initiative, conducted by the National Center for Education Statistics (NCES), to collect, analyze, report on, and promote the use of high-quality, pre-kindergarten through grade 12 (pre-K–12) performance data. By centralizing data provided by state education agencies about state level data, local education agencies, and schools, NCES uses the EDFacts data to report on students, schools, staff, services, and education outcomes at the state, district, and school levels. The centralized approach provides ED users with the ability to efficiently analyze and report on submitted data and has reduced the reporting burden for state and local data producers through the use of streamlined data collection, analysis, and reporting tools. EDFacts collects information on behalf of ED grant and program offices for approximately 170 data groups for all 50 states, Washington DC, Puerto Rico, and seven outlying areas and freely associated states (American Samoa, Federated States of Micronesia, Guam, Marshall Islands, Commonwealth of the Northern Mariana Islands, Republic of Palau, and the U.S. Virgin Islands), the Department of Defense Education Activity (DoDEA), and the Bureau of Indian Education (BIE). This request is to collect EDFacts data for the 2022–23, 2023–24, and 2024–25 school years. This collection package will be available for public comment during two open periods, a 60 day and a 30 day, after which revisions will be made accordingly. As part of the public comment period review, ED requests that SEAs and other stakeholders respond to the directed questions found in Attachment D. Due to overlap in the timing of data collection activities between consecutive years of the EDFacts collection, we are carrying over in this submission the approved SY 2021–22 data collection, which is scheduled to end in February 2023.

Dated: November 9, 2021.

Stephanie Valentine,

PRA Coordinator, Strategic Collections and Clearance, Governance and Strategy Division, Office of Chief Data Officer, Office of Planning, Evaluation and Policy Development.

[FR Doc. 2021–24883 Filed 11–12–21; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

Tests Determined To Be Suitable for Use in the National Reporting System for Adult Education

Correction

In notice document 2021–22951, appearing on pages 58258–58260 in the issue of Thursday, October 21, 2021, make the following change:

1. On page 58259, in the first column, lines 66–68, text should appear as follows:

NRS.

TESTS DETERMINED TO BE SUITABLE FOR USE IN THE NRS FOR A SEVEN–YEAR PERIOD FROM THE

2. On the same page, in the second column, lines 62–69, text should appear as follows:

acls/assessment/.

TEST DETERMINED TO BE SUITABLE FOR USE IN THE NRS FOR A THREE-YEAR PERIOD FROM THE PUBLICATION DATE OF THE ORIGINAL NOTICE IN WHICH IT WAS ANNOUNCED AND APPROVED FOR AN EXTENDED PERIOD THROUGH MARCH 7, 2023:

3. On the same page, in the third column, lines 14–20, text should appear as follows:

www.casas.org/.

ESL TESTS PREVIOUSLY APPROVED FOR AN EXTENDED PERIOD THROUGH FEBRUARY 2, 2021, AND APPROVED FOR AN ADDITIONAL EXTENDED PERIOD THROUGH FEBRUARY 2, 2023:

[FR Doc. C1–2021–22951 Filed 11–12–21; 8:45 am]

BILLING CODE0099–10–P

DEPARTMENT OF ENERGY

Environmental Management Advisory Board

AGENCY: Office of Environmental Management, Department of Energy.

ACTION: Notice of open virtual meeting.

SUMMARY: This notice announces an online virtual meeting of the Environmental Management Advisory Board (EMAB). The Federal Advisory Committee Act requires that public notice of this meeting be announced in the **Federal Register**.

DATES: Monday, December 13, 2021; 1:00 p.m.–3:00 p.m. ET.

ADDRESSES: This meeting will be held virtually via Zoom. To attend, please contact Alyssa Harris by email, *Alyssa.Harris@em.doe.gov*, no later than 5:00 p.m. EDT on Monday, December 6, 2021.

To Submit Public Comment: Public comments will be accepted via email prior to and after the meeting. Comments received no later than 5:00 p.m. EDT on Monday, December 6, 2021, will be read aloud during the virtual meeting. Comments will also be accepted after the meeting by no later than 5:00 p.m. EDT on Monday, December 20, 2021. Please send comments to Alyssa Harris at *Alyssa.Harris@em.doe.gov.*

FOR FURTHER INFORMATION CONTACT: Alyssa Harris, EMAB Federal Coordinator. U.S. Department of Energy, 1000 Independence Avenue SW, Washington, DC 20585. Phone (202) 430–9624 or Email: *Alyssa.Harris@em.doe.gov.*

SUPPLEMENTARY INFORMATION:

Purpose of the Board: The purpose of EMAB is to provide the Assistant Secretary for Environmental Management (EM) with independent advice and recommendations on corporate issues confronting the EM program. EMAB's membership reflects a diversity of views, demographics, expertise, and professional and academic experience. Individuals are appointed by the Secretary of Energy to serve as either special Government employees or representatives of specific interests and/or entities.

Tentative Agenda:

- Reading of Public Comment
- Remarks from EM leadership
- EM Regulatory and Policy Affairs Update
- Ethics Briefing for EMAB Members
- Board Business

Public Participation: The online virtual meeting is open to the public. Written statements may be filed with the Board either before or after the meeting by sending them to Alyssa Harris at the aforementioned email address. The Designated Federal Officer is empowered to conduct the conference call in a fashion that will facilitate the orderly conduct of business. Individuals wishing to make public comments should email them as directed above.

Minutes: Minutes will be available by writing or calling Alyssa Harris at the address or phone number listed above. Minutes will also be available at the following website: *https://www.energy.gov/em/listings/emab-meetings.*

Signed in Washington, DC on November 9, 2021.

LaTanya Butler,

Deputy Committee Management Officer.

[FR Doc. 2021–24881 Filed 11–12–21; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP22–12–000]

Florida Gas Transmission Company, LLC; Notice of Request Under Blanket Authorization and Establishing Intervention and Protest Deadline

Take notice that on October 28, 2021, Florida Gas Transmission Company, LLC (FGT), 1300 Main Street, Houston, Texas 77002, filed in the above referenced docket, a prior notice request pursuant to sections 157.205, 157.208, and 157.210 of the Commission's regulations under the Natural Gas Act (NGA) and FGT's blanket certificate issued in Docket No. CP82–553–000, for authorization to increase mainline capacity, and make minor auxiliary facility modifications under Section 2.55(a) of the Commission's regulations on compressor units 1007 and 1008 at Compressor Station 10 (CS 10) in Perry County, Mississippi. The proposed modifications at CS 10 will allow FGT to flow natural gas from west to east, and transport incremental interstate gas from an existing receipt point in George County, Mississippi, to three existing delivery points in Mobile County, Alabama. The proposed project is designed primarily to meet the demand for an additional 17,500 million British Thermal Units per day (MMBtu/d) of natural gas transportation to be delivered for Clarke-Mobile Counties Gas District (CMCGas) in FGT's Western Division in the Alabama Gulf Coast natural gas market, all as more fully set forth in the application, which is on file with the Commission and open to public inspection.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://ferc.gov*) using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. At this time, the Commission has suspended access to the Commission's Public Reference Room, due to the proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19), issued by the President on March 13, 2020. For assistance, contact FERC at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TYY, (202) 502–8659.

Any questions regarding this prior notice request should be directed to Blair Lichtenwalter, Senior Director, Certificates, Florida Gas Transmission Company, LLC, 1300 Main Street, P.O. Box 4967, Houston, Texas 77210–4967, at (713) 989–2605, or by email to *Blair.Lichtenwalter@energytransfer.com.*

Public Participation

There are three ways to become involved in the Commission's review of this project: You can file a protest to the project, you can file a motion to intervene in the proceeding, and you

can file comments on the project. There is no fee or cost for filing protests, motions to intervene, or comments. The deadline for filing protests, motions to intervene, and comments is 5:00 p.m. Eastern Time on January 7, 2022. How to file protests, motions to intervene, and comments is explained below.

Protests

Pursuant to section 157.205 of the Commission's regulations under the NGA,[1] any person [2] or the Commission's staff may file a protest to the request. If no protest is filed within the time allowed or if a protest is filed and then withdrawn within 30 days after the allowed time for filing a protest, the proposed activity shall be deemed to be authorized effective the day after the time allowed for protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request for authorization will be considered by the Commission.

Protests must comply with the requirements specified in section 157.205(e) of the Commission's regulations,[3] and must be submitted by the protest deadline, which is January 7, 2022. A protest may also serve as a motion to intervene so long as the protestor states it also seeks to be an intervenor.

Interventions

Any person has the option to file a motion to intervene in this proceeding. Only intervenors have the right to request rehearing of Commission orders issued in this proceeding and to subsequently challenge the Commission's orders in the U.S. Circuit Courts of Appeal.

To intervene, you must submit a motion to intervene to the Commission in accordance with Rule 214 of the Commission's Rules of Practice and Procedure [4] and the regulations under the NGA [5] by the intervention deadline for the project, which is January 7, 2022. As described further in Rule 214, your motion to intervene must state, to the extent known, your position regarding the proceeding, as well as your interest in the proceeding. For an individual, this could include your status as a landowner, ratepayer, resident of an impacted community, or recreationist. You do not need to have property directly impacted by the project in order to intervene. For more information about motions to intervene, refer to the FERC website at *https://www.ferc.gov/resources/guides/how-to/intervene.asp.*

All timely, unopposed motions to intervene are automatically granted by operation of Rule 214(c)(1). Motions to intervene that are filed after the intervention deadline are untimely and may be denied. Any late-filed motion to intervene must show good cause for being late and must explain why the time limitation should be waived and provide justification by reference to factors set forth in Rule 214(d) of the Commission's Rules and Regulations. A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies (paper or electronic) of all documents filed by the applicant and by all other parties.

Comments

Any person wishing to comment on the project may do so. The Commission considers all comments received about the project in determining the appropriate action to be taken. To ensure that your comments are timely and properly recorded, please submit your comments on or before January 7, 2022. The filing of a comment alone will not serve to make the filer a party to the proceeding. To become a party, you must intervene in the proceeding.

How To File Protests, Interventions, and Comments

There are two ways to submit protests, motions to intervene, and comments. In both instances, please reference the Project docket number CP22–12–000 in your submission.

(1) You may file your protest, motion to intervene, and comments by using the Commission's *eFiling* feature, which is located on the Commission's website (*www.ferc.gov)* under the link to *Documents and Filings.* New eFiling users must first create an account by clicking on ''*eRegister.*'' You will be asked to select the type of filing you are making; first select ''General'' and then select ''Protest'', ''Intervention'', or ''Comment on a Filing''; or [6]

(2) You can file a paper copy of your submission by mailing it to the address below.[7] Your submission must reference the Project docket number CP22–12–000.

Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426.

The Commission encourages electronic filing of submissions (option 1 above) and has eFiling staff available to assist you at (202) 502–8258 or *FercOnlineSupport@ferc.gov.*

Protests and motions to intervene must be served on the applicant either by mail at: 1300 Main Street, P.O. Box 4967, Houston, Texas 77210–4967, or email (with a link to the document) at: *Blair.Lichtenwalter@energytransfer.com.* Any subsequent submissions by an intervenor must be served on the applicant and all other parties to the proceeding. Contact information for parties can be downloaded from the service list at the eService link on FERC Online.

Tracking the Proceeding

Throughout the proceeding, additional information about the project will be available from the Commission's Office of External Affairs, at (866) 208–FERC, or on the FERC website *at www.ferc.gov* using the ''eLibrary'' link as described above. The eLibrary link also provides access to the texts of all formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. For more information and to register, go to *www.ferc.gov/docs-filing/esubscription.asp.*

Dated: November 8, 2021.

Kimberly D. Bose,

Secretary.

[FR Doc. 2021–24831 Filed 11–12–21; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following exempt wholesale generator filings:

Docket Numbers: EG22–22–000.

Applicants: Skipjack IA, LLC.

[1] 18 CFR 157.205.

[2] Persons include individuals, organizations, businesses, municipalities, and other entities. 18 CFR 385.102(d).

[3] 18 CFR 157.205(e).

[4] 18 CFR 385.214.

[5] 18 CFR 157.10.

[6] Additionally, you may file your comments electronically by using the eComment feature, which is located on the Commission's website at *www.ferc.gov* under the link to Documents and Filings. Using eComment is an easy method for interested persons to submit brief, text-only comments on a project.

[7] Hand-delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

Description: Notice of Self-Certification of Exempt Wholesale Generator Status of Skipjack IA, LLC.
Filed Date: 11/8/21.
Accession Number: 20211108–5078.
Comment Date: 5 p.m. ET 11/29/21.

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER21–2449–002.
Applicants: Assembly Solar II, LLC.
Description: Compliance filing: Informational Filing for Achieving Commercial Operation to be effective 11/5/2021.
Filed Date: 11/8/21.
Accession Number: 20211108–5193.
Comment Date: 5 p.m. ET 11/29/21.

Docket Numbers: ER22–188–000.
Applicants: Indra Power Business CT, LLC.
Description: Supplement to October 22, 2021 Indra Power Business CT, LLC tariff filing.
Filed Date: 11/5/21.
Accession Number: 20211105–5215.
Comment Date: 5 p.m. ET 11/26/21.

Docket Numbers: ER22–357–000.
Applicants: PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: Amendment to WMPA, SA No. 5545; Queue No. AE2–125 to be effective 12/11/2019.
Filed Date: 11/8/21.
Accession Number: 20211108–5097.
Comment Date: 5 p.m. ET 11/29/21.

Docket Numbers: ER22–358–000.
Applicants: Public Service Electric and Gas Company, PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: Public Service Electric and Gas Company submits tariff filing per 35.13(a)(2)(iii: Revisions to the CTOA, Section 8 re: TO Voting Structure to be effective 1/10/2022.
Filed Date: 11/8/21.
Accession Number: 20211108–5109.
Comment Date: 5 p.m. ET 11/29/21.

Docket Numbers: ER22–360–000.
Applicants: PJM Interconnection, L.L.C.
Description: Tariff Amendment: Notice of Cancellation of WMPA, SA No. 4601; Queue Nos. AB2–010/AB2–011 to be effective 2/5/2019.
Filed Date: 11/8/21.
Accession Number: 20211108–5139.
Comment Date: 5 p.m. ET 11/29/21.

Docket Numbers: ER22–361–000.
Applicants: AEP Texas Inc.
Description: § 205(d) Rate Filing: AEPTX-Concho Valley Solar 1st A&R Generation Interconnection Agreement to be effective 10/27/2021.
Filed Date: 11/8/21.
Accession Number: 20211108–5153.
Comment Date: 5 p.m. ET 11/29/21.

The filings are accessible in the Commission's eLibrary system (*https://elibrary.ferc.gov/idmws/search/fercgensearch.asp*) by querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: November 8, 2021.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2021–24854 Filed 11–12–21; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. IC22–2–000]

Commission Information Collection Activities (FERC–519, FERC–545, FERC–546, FERC–549C, and FERC–732); Comment Request; Extension

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of information collection and request for comments.

SUMMARY: In compliance with the requirements of the Paperwork Reduction Act of 1995, the Federal Energy Regulatory Commission (Commission or FERC) is soliciting public comment on the currently approved information collection, FERC–519, (Application under Federal Power Act Section 203); FERC–545, (Gas Pipeline Rates: Rate Change (Non-Formal)); FERC–546, (Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility); FERC–549C, (Standards for Business Practices of Interstate Natural Gas Pipelines); FERC–732, (Electric Rate Schedule and Tariffs: Long-Term Firm Transmission Rights in Organized Electricity Markets). The above five collections are a part of a combined notice only and are not being combined into one OMB Collection number.

DATES: Comments on the collection of information are due January 14, 2022.

ADDRESSES: You may submit copies of your comments (identified by Docket No. IC22–2–000) by one of the following methods:

Electronic filing through *http://www.ferc.gov,* is preferred.

- *Electronic Filing:* Documents must be filed in acceptable native applications and print-to-PDF, but not in scanned or picture format.
- For those unable to file electronically, comments may be filed by USPS mail or by hand (including courier) delivery:
  - ○ *Mail via U.S. Postal Service Only:* Addressed to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.
  - ○ *Hand (Including Courier) Delivery:* Deliver to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

Instructions: All submissions must be formatted and filed in accordance with submission guidelines at: *http://www.ferc.gov.* For user assistance, contact FERC Online Support by email at *ferconlinesupport@ferc.gov,* or by phone at (866) 208–3676 (toll-free).

Docket: Users interested in receiving automatic notification of activity in this docket or in viewing/downloading comments and issuances in this docket may do so at *http://www.ferc.gov.*

FOR FURTHER INFORMATION CONTACT: Ellen Brown may be reached by email at *DataClearance@FERC.gov,* telephone at (202) 502–8663.

SUPPLEMENTARY INFORMATION:

1. FERC–519

Title: FERC–519, Application under Federal Power Act Section 203.[1]
OMB Control No.: 1902–0082.
Type of Request: Three-year extension of the FERC–519 information collection requirements with no changes to the current reporting requirements.

Abstract: The Commission requires that public utility officers must seek authorization under amended section 203(a)(1)(B) of the Federal Power Act (FPA) to merge or consolidate, directly or indirectly, its facilities subject to the jurisdiction of the Commission, or any part thereof, with the facilities of any other person, or any part thereof, that are subject to the jurisdiction of the Commission and have a value in excess of $10 million, by any means

[1] 16 U.S.C. 824b.

whatsoever. In addition, as required by the Act, the Commission establishes a requirement to submit a notification filing for mergers or consolidations by a public utility if the facilities to be acquired have a value in excess of $1 million and such public utility is not required to secure Commission authorization under amended section 203(a)(1)(B). The information collected under the FERC–519 enables the Commission to meet its statutory responsibilities regarding public utility disposition, merger, consolidation of facilities, purchase, or acquisition oversight and enforcement in accordance with the FPA as referenced above. Without this information, FERC would be unable to meet these responsibilities. The required information includes descriptions of corporate attributes of the party or parties to the proposed transaction (*e.g.* a sale, lease, or other disposition, merger, or consolidation of facilities, or purchase of other acquisition of the securities of a public utility and the facilities or other property involved in the transaction), statements about effect of the transaction, and the applicant's proof that the transaction will be consistent with the public interest. It will enable the Commission to meet its statutory responsibilities regarding its FPA section 203 oversight of public utility dispositions, mergers, or consolidation of facilities, and associated oversight and enforcement responsibilities under the FPA as referenced above. The required information to be collected in the notification filing (established by the addition of 18 CFR part 33.12) for certain transactions includes descriptions of corporate attributes of the party or parties to the transaction and the facilities involved. FPA section 203 requires a filing on the occasion that a public utility proposes to dispose of jurisdictional facilities, merge such facilities, or acquire the securities of another public utility. Public Utilities consist of:

- Corporate;
- Information Technology Management;
- General Accounting;
- Personnel and Payroll;
- Transportation;
- Tariffs and Rates;
- Insurance;
- Operations and Maintenance;
- Plant and Depreciation;
- Purchase and Stores;
- Revenue Accounting and Collection;
- Tax;
- Treasury; and
- Miscellaneous.

Type of Respondents: Public utility officers regulated by the FPA.

Estimate of Annual Burden: [2] The Commission estimates the total annual burden and cost [3] for this information collection as follows:

FERC–519: APPLICATION UNDER FEDERAL POWER ACT SECTION 203

	Number of respondents (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden & cost per response (4)	Total annual burden hours (total annual cost) (3) * (4) = (5)	Cost per respondent (5) ÷ (1)
FERC–519 (FPA Section 203 Filings) [4] ...	131	1	131	324.43 hr.[5]; $28,225.41	42,500.33 hrs.; $3,697,528.71.	$28,225.41

2. FERC–545

Title: FERC–545, Gas Pipeline Rates: Rate Change (Non-Formal)

OMB Control No.: 1902–0154.

Type of Request: Three-year extension of the FERC–545 information collection requirements with no changes to the current reporting requirements.

Abstract: FERC–545 is required to implement Sections 4, 5, and 16 of the Natural Gas Act (NGA), (15 U.S.C. 717c, 717d, and 717o). NGA Sections 4, 5, and 16 authorize the Commission to inquire into rate structures and methodologies and to set rates at a just and reasonable level. Specifically, a natural gas company must obtain Commission authorization for all rates and charges made, demanded, or received in connection with the transportation or sale of natural gas in interstate commerce.

Under the NGA, a natural gas company's rates must be just and reasonable and not unduly discriminatory or preferential. The Commission may act under different sections of the NGA to effect a change in a natural gas company's rate. When the Commission reviews rate increases that a natural gas company has proposed, it is subject to the requirement of Section 4(e) of the NGA. Under Section 4(e), the natural gas company bears the burden of proving that its proposed rates are just and reasonable. On the other hand, when the Commission seeks to impose its own rate determination, it must do so in compliance with Section 5(a) of the NGA. Under Section 5, the Commission must first establish that its alternative rate proposal is both just and reasonable.

Section 16 of the NGA states that the Commission ''shall have the power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out provisions of [the NGA].'' In other words, Section 16 of the NGA grants the Commission the power to define accounting, technical and trade terms, prescribe forms, statements, declarations or reports and to prescribe rules and regulations.

Pipelines adjust their tariffs to meet market and customer needs. The Commission's review of these proposed changes is required to ensure rates remain just and reasonable and that services are not provided in an unduly or preferential manner. The Commission's regulations in 18 CFR part 154 specify what changes are

[2] ''Burden'' is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to Title 5 Code of Federal Regulations 1320.3.

[3] Commission staff estimates that the industry's skill set and cost (for wages and benefits) for FERC–519 are approximately the same as the Commission's average cost. The FERC 2021 average salary plus benefits for one FERC full-time equivalent (FTE) is $180,703/year (or $87.00/hour).

[4] Commission staff estimates that approximately 26 section 203 filings will change from full section 203 filings to the notification filing described above and will take one burden hour to complete. The number of respondents and responses is based on Commission staff's estimate that 13 percent of the approximately 200 section 203 filings received will be affected. This represents a significant reduction in burden hours.

[5] With this amendment each of the 26 affected entities and their related filings (*i.e.,* the entities that now only have to file the section 203 notification filings) is reduced to 1 hour.

allowed and the procedures for requesting Commission approval.

The Commission uses information in FERC–545 to examine rates, services, and tariff provisions related to natural gas transportation and storage services. The following filing categories are subject to FERC–545: (1) Tariff Filings—filings regarding proposed changes to a pipeline's tariff (including Cost Recovery Mechanisms for Modernization of Natural Gas Facilities filings in Docket No. PL15–1) and any related compliance filings; (2) Rate Filings—rate-related filings under NGA sections 4 and 5 and any related compliance filings and settlements; (3) Informational Reports; (4) Negotiated Rate and Non-Conforming Agreement Filings; (5) North American Energy Standards Board (NAESB) (RM96–1–042) Version 3.2; and (6) Market-Based Rates for Storage Filings (Part 284.501–505).

Type of Respondents: Natural gas pipelines under the jurisdiction of NGA.

Estimate of Annual Burden:[6] The public reporting burden has increased for this information collection due to normal fluctuations in industry and the inclusion of tariff filings in compliance with Order No. 587–Z. On July 15, 2021, in Docket No. RM96–1–042, the Commission amended its regulations to incorporate by reference the North American Energy Standards Board (NAESB) Wholesale Quadrant Version 3.2 standards. The revisions made by NAESB Version 3.2 are designed to enhance the natural gas industries' cyber security measures.

The Commission estimates the annual public reporting burden and cost for the information collection as follows:

FERC–545: GAS PIPELINE RATES: RATE CHANGE (NON-FORMAL)

	Number of respondents (1)	Average number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden and cost per response[7] (4)	Total annual burden hours and total annual cost (3) * (4) = (5)	Cost per respondent ($) (5) ÷ (1)
Tariff Filings	109	2.768	301.712	211 hrs.; $20,467	63,661.232 hrs.; $6,175,139.50.	$56,652.66
Rate Filings	32	2	64	354 hrs.; $34,338	22,656 hrs.; $2,197,632	56,980
Informational Reports	100	1.770	177	235 hrs.; $22,795	41,595 hrs.; $4,034,715	40,347.15
Negotiated Rates & Non-Conforming Agreement Filings.	69	11	759	233 hrs.; $22,601	176,847 hrs.; $17,154,159	248,611
Market-Base Rates for Storage Filings	2	1	2	230 hrs.; $22,310	460 hrs.; $44,620	22,310
NAESB (version 3.2) one time over 3 years carried over from RM96–1–42.	178	1	178	3.33 hrs.; $323.01	592.74 hrs.; $57,495.78	323.01
Total			1,482		305,811.97 hrs.; $29,663,761.28.	

3. FERC–546

Title: FERC–546, Certificated Rate Filings: Gas Pipeline Rates.

OMB Control No.: 1902–0155.

Type of Request: Three-year extension of the FERC–546 information collection requirements with no changes to the current reporting requirements.

Abstract: The Commission reviews the FERC–546 materials to decide whether to approve rates and tariff changes associated with an application for a certificate under Natural Gas Act (NGA) section 7(c) (15 U.S.C. 717). Additionally, FERC reviews FERC–546 materials in NGA section 4(f) (15 U.S.C. 717), storage applications, to evaluate an applicant's market power and determine whether to grant market-based rate authority to the applicant. The Commission uses the information in FERC–546 to monitor jurisdictional transportation, natural gas storage, and unbundled sales activities of interstate natural gas pipelines and Hinshaw[8] pipelines. In addition to fulfilling the Commission's obligations under the NGA, the FERC–546 enables the Commission to monitor the activities and evaluate transactions of the natural gas industry, ensure competitiveness, and improve efficiency of the industry's operations. In summary, the Commission uses the information to:

- ensure adequate customer protections under NGA section 4(f);
- review rate and tariff changes filed under NGA section 7(c) for certification of natural gas pipeline transportation and storage services;
- provide general industry oversight; and
- supplement documentation during the pipeline audits process.

Failure to collect this information would prevent the Commission from monitoring and evaluating transactions and operations of jurisdictional pipelines and performing its regulatory functions.

Type of Respondents: Jurisdictional pipeline companies and storage operators.

Estimate of Annual Burden:[9] The Commission estimates the burden and cost for this information collection as follows:

[6] The Commission defines burden as the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, reference 5 Code of Federal Regulations 1320.3.

[7] The estimated hourly cost (salary plus benefits) provided in this section is based on the salary figures for May 2021 posted by the Bureau of Labor Statistics for the Utilities sector (available at *https://www.bls.gov/oes/current/naics3_221000.htm*) and scaled to reflect benefits using the relative importance of employer costs for employee compensation from June 2021 (available at *https://www.bls.gov/news.release/ecec.nr0.htm*). The hourly estimates for salary plus benefits are:

Computer and Information Systems Manager (Occupation Code: 11–3021), $103.61.

Computer and Information Analysts (Occupation Code: 15–1120(1221), $67.99.

Electrical Engineer (Occupation Code: 17–2071), $72.15.

Legal (Occupation Code: 23–0000), $142.25.

The average hourly cost (salary plus benefits), weighting all of these skill sets evenly, is $96.50. We round it to $97/hour.

[8] Hinshaw pipelines are those that receive all out-of-state gas from entities within or at the boundary of a state if all the natural gas so received is ultimately consumed within the state in which it is received, 15 U.S.C. 717(c). Congress concluded that Hinshaw pipelines are ''matters primarily of local concern,'' and so are more appropriately regulated by pertinent state agencies rather than by FERC. The Natural Gas Act section 1(c) exempts Hinshaw pipelines from FERC jurisdiction. A Hinshaw pipeline, however, may apply for a FERC certificate to transport gas outside of state lines.

[9] ''Burden'' is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to Title 5 Code of Federal Regulations 1320.3.

FERC–546 (CERTIFICATED RATE FILINGS: GAS PIPELINE RATES)

	Annual number of respondents (1)	Annual number of responses per respondent (2)	Total number of responses (rounded) (1) * (2) = (3)	Average burden and cost per response [10] (rounded) (4)	Total annual burden hours and total annual cost (rounded) (3) * (4) = (5)	Cost per respondent ($) (rounded) (5) ÷ (1)
Pipeline Certificate Filings and Storage Applications.	47	[11] 1.595	74.965	500 hrs.; $41,652	37,482.50 hrs.; $3,122,442.18.	$66,434.94

4. FERC–549C

Title: FERC–549C, Standards for Business Practices of Interstate Natural Gas Pipelines.

OMB Control No.: 1902–0174.

Type of Request: Three-year extension of the FERC–549C information collection requirements with no changes to the current reporting requirements.

Abstract: The business practice standards under FERC–549C are required to carry out the Commission's policies in accordance with the general authority in sections 4, 5, 7, 8, 10, 14, 16, and 20 of the Natural Gas Act (NGA),[12] and sections 311, 501, and 504 of the Natural Gas Policy Act of 1978 (NGPA).[13] The Commission adopted these business practice standards in order to update and standardize the natural gas industry's business practices and procedures in addition to improving the efficiency of the gas market and the means by which the gas industry conducts business across the interstate pipeline grid.

In various orders since 1996, the Commission has adopted regulations to standardize the business practices and communication methodologies of interstate natural gas pipelines proposed by the North American Energy Standards Board (NAESB) in order to create a more integrated and efficient pipeline industry.[14] Generally, when and if NAESB-proposed standards (*e.g.* consensus standards developed by the Wholesale Gas Quadrant (WGQ) [15]) are approved by the Commission, the Commission incorporates them by reference into its approval. The process of standardizing business practices in the natural gas industry began with a Commission initiative to standardize electronic communication of capacity release transactions. The outgrowth of the initial Commission standardization efforts produced working groups composed of all segments of the natural gas industry and, ultimately, the Gas Industry Standards Board (GISB), a consensus organization open to all members of the gas industry was created. GISB was succeeded by NAESB.

NAESB is a voluntary non-profit organization comprised of members from the retail and wholesale natural gas and electric industries. NAESB's mission is to take the lead in developing standards across these industries to simplify and expand electronic communication and to streamline business practices. NAESB's core objective is to facilitate a seamless North American marketplace for natural gas, as recognized by its customers, the business community, industry participants, and regulatory bodies. NAESB has divided its efforts among four quadrants including two retail quadrants, a wholesale electric quadrant, and the WGQ. The NAESB WGQ standards are a product of this effort. Industry participants seeking additional or amended standards (to include principles, definitions, standards, data elements, process descriptions, and technical implementation instructions) must submit a request to the NAESB office, detailing the change, so that the appropriate process may take place to amend the standards.

Failure to collect the FERC–549C data would prevent the Commission from monitoring and properly evaluating pipeline transactions and/or meeting statutory obligations under both the NGA and NGPA.

On August 17, 2020, NAESB filed a report informing the Commission that it had adopted and ratified WGQ Version 3.2 of its business practice standards applicable to interstate natural gas pipelines. Version 3.2 of the WGQ includes business practice standards developed and modified in response to industry requests and directives from the NAESB Board of Directors. This version also includes the standards developed in response to the recommendations of Sandia National Laboratory (Sandia),[16] which in 2019 issued a cybersecurity surety assessment of the NAESB standards sponsored by DOE (Sandia Surety Assessment),[17] and the standards developed to enable the use of distributed ledger technologies when transacting the NAESB Base Contract for Sale and Purchase of Natural Gas. The NAESB report identifies all the changes made to the WGQ Version 3.1 Standards and summarizes the deliberations that led to the changes being made. It also

[10] The hourly cost (for salary plus benefits) uses the figures from the Bureau of Labor Statistics, June 2021, for positions involved in the reporting and recordkeeping requirements. These figures include salary (*https://www.bls.gov/oes/current/naics2_22.htm*) and benefits *http://www.bls.gov/news.release/ecec.nr0.htm*) and are:

Electrical Engineer (Occupation Code: 17–2071; $72.15/hour).

Management Analyst (Occupation Code: 13–1111; $68.39/hour).

Accounting (Occupation Code: 13–2011; $57.41/hours).

Computer and Mathematical (Occupation Code: 15–0000; $65.73/hour).

Legal (Occupation Code: 23–0000; $142.25/hour).

The average hourly cost (salary plus benefits) is calculated weighting each of the previously mentioned wage categories as follows: $72.15/hour (0.4) + $68.39/hour (0.2) + $57.41/hour (0.1) + $65.73/hour (0.1) + $142.25/hour (0.2) = $83.304/hour. The Commission rounds this figure to $83/hour.

[11] This figure was calculated by dividing the total number of responses ( ) by the total number of respondents (47). The resulting figure was then rounded to the nearest thousandth place.

[12] 15 U.S.C. 717c–717w.

[13] 15 U.S.C. 3301–3432.

[14] This series of orders began with the Commission's issuance of *Standards for Business Practices of Interstate Natural Gas Pipelines,* Order No. 587, FERC Stats. & Regs. ¶ 31,038 (1996).

[15] An accredited standards organization under the auspices of the American National Standards Institute (ANSI).

[16] Sandia is a multidisciplinary national laboratory and federally funded research and development center for the U.S. Department of Energy's (DOE) National Nuclear Security Administration that supports numerous federal, state, and local government agencies, companies, and organizations.

[17] In April 2017, NAESB announced that Sandia, through funding provided by DOE, would be performing a surety assessment of the NAESB standards. As determined by Sandia and DOE, the purpose of the surety assessment was to analyze cybersecurity elements within the standards, focusing on four areas: (1) The NAESB Certification Program for Accredited Certification Authorities, including the Wholesale Electric Quadrant (WEQ)-012 Public Key Infrastructure Business Practice Standards, the NAESB Accreditation Requirements for Authorized Certificate Authorities, and the Authorized Certification Authority Process; (2) the WEQ Open Access Same-Time Information Systems suite of standards; (3) the WGQ and Retail Markets Quadrant internet Electronic Transport (IET) and Quadrant Electronic Delivery Mechanism (EDM) Related Standards Manual; and (4) a high-level dependency analysis between the gas and electric markets to evaluate the different security paradigms the markets employ.

identifies changes to the existing standards that were considered but not adopted due to a lack of consensus or other reasons.

Type of Respondents: Natural gas pipelines under the jurisdiction of NGA and NGPA.

Estimate of Annual Burden: [18] The Commission estimates the total annual burden and cost [19] for this information collection as follows:

FERC–549C: STANDARDS FOR BUSINESS PRACTICES OF INTERSTATE NATURAL GAS PIPELINES

	Number of respondents	Average number of responses per respondent	Total number of responses	Average burden & cost per response [20]	Total annual burden hours & total annual cost	Cost per respondent ($)
	(1)	(2)	(1) * (2) = (3)	(4)	(3) * (4) = (5)	(5) ÷ (1)
Standards for Business Practices of Interstate Natural Gas Pipelines.	178	1	178	33.33 hrs.; $3,135.39	5,932.74 hrs.; $558,098.78	$3,135.39

5. FERC–732

Title: FERC–732, Electric Rate Schedule and Tariffs: Long-Term Firm Transmission Rights in Organized Electricity Markets.

OMB Control No.: 1902–0245.

Type of Request: Three-year extension of the FERC–732 information collection requirement with no changes to the current reporting requirements.

Abstract: 18 CFR part 42 provides the reporting requirements of FERC–732 as they pertain to long-term transmission rights. To implement section 1233 [21] of the Energy Policy Act of 2005 (EPAct 2005),[22] the Commission requires each transmission organization that is a public utility with one or more organized electricity markets to make available long-term firm transmission rights that satisfy each of the Commission's guidelines.[23]

The FERC–732 regulations require that transmission organizations (that are public utilities with one or more organized electricity markets) choose one of two ways to file:

- File tariff sheets making long-term firm transmission rights available that are consistent with each of the guidelines established by FERC.
- File an explanation describing how their existing tariffs already provide long-term firm transmission rights that are consistent with the guidelines.

Additionally, the Commission requires each transmission organization to make its transmission planning and expansion procedures and plans available to the public. FERC–732 enables the Commission to exercise its wholesale electric rate and electric power transmission oversight and enforcement responsibilities in accordance with the FPA, the Department of Energy Organization Act (DOE Act), and EPAct 2005.

Type of Respondents: Public utility with one or more organized electricity markets.

Estimate of Annual Burden: [24] The Commission estimates the total burden and cost [25] for this information collection as follows.

FERC–732, ELECTRIC RATE SCHEDULES AND TARIFFS: LONG-TERM FIRM TRANSMISSION RIGHTS IN ORGANIZED ELECTRICITY MARKETS

	Number of respondents	Annaul number of responses per respondent	Total number of responses	Total annual burden hours & total annual cost ($)	Cost per respondent ($)
	(1)	(2)	(1) * (2) = (3)	(3) * (4) = (5)	(5) ÷ (1)
Public utility with one or more organized electricity markets	1	1	[26] 1	1,180 hrs.; $102,660	$102,660

Comments: Comments are invited on: (1) Whether the collection of information is necessary for the proper performance of the functions of the Commission, including whether the information will have practical utility; (2) the accuracy of the agency's estimate of the burden and cost of the collection of information, including the validity of the methodology and assumptions used; (3) ways to enhance the quality, utility and clarity of the information collection;

[18] ''Burden'' is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to Title 5 Code of Federal Regulations 1320.3.

[19] Commission staff estimates that the industry's skill set and cost (for wages and benefits) for FERC–549C are approximately the same as the Commission's average cost. The FERC 2021 average salary plus benefits for one FERC full-time equivalent (FTE) is $180,703/year (or $87.00/hour) posted by the Bureau of Labor Statistics for the Utilities sector (available at *https://www.bls.gov/oes/current/naics3_221000.htm*).

[20] The estimated hourly cost (salary plus benefits) provided in this section is based on the salary figures for May 2021 posted by the Bureau of Labor Statistics for the Utilities sector (available at *http://www.bls.gov/oes/current/naics2_22.htm#13-0000*) and scaled to reflect benefits using the relative importance of employer costs in employee compensation from June 2021 (available at *https://www.bls.gov/oes/current/naics2_22.htm*). The hourly estimates for salary plus benefits are:

Petroleum Engineer (Occupation Code: 17–2171), $74.20.

Computer Systems Analysts (Occupation Code: 15–1120), $67.99.

Legal (Occupation Code: 23–0000), $142.25.

Economist (Occupation Code: 19–3011), $75.75.

The average hourly cost (salary plus benefits) is calculated weighting each of the aforementioned wage categories as follows: $74.20 (0.3) + $142.25 (0.3) + $67.99 (0.15) + $75.75 (0.25) = $94.07. The Commission rounds it to $90/hour.

[21] 16 U.S.C. 824.

[22] 16 U.S.C. 824q.

[23] 18 CFR 42.1(d).

[24] Burden is defined as the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to 5 CFR 1320.3.

[25] FERC staff estimates that industry costs for salary plus benefits are similar to Commission costs. The FERC 2021 average salary plus benefits for one FERC full-time equivalent (FTE) is $180,703/year (or $87.00/hour) posted by the Bureau of Labor Statistics for the Utilities sector (available at *https://www.bls.gov/oes/current/naics3_221000.htm.*)

[26] The ''1'' Tariff filing is a placeholder for future fillers.

and (4) ways to minimize the burden of the collection of information on those who are to respond, including the use of automated collection techniques or other forms of information technology.

Dated: November 1, 2021.

Kimberly D. Bose,

Secretary.

[FR Doc. 2021–24860 Filed 11–12–21; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP22–11–000]

Texas Gas Transmission, LLC; Notice of Request Under Blanket Authorization and Establishing Intervention and Protest Deadline

Take notice that on October 27, 2021, Texas Gas Transmission, LLC (Texas Gas), 9 Greenway Plaza, Houston, Texas, 77046, filed in the above referenced docket a prior notice pursuant to Section 157.205 and 157.208(b) of the Federal Energy Regulatory Commission's regulations under the Natural Gas Act and the blanket certificate issued by the Commission in Docket No. CP82–407–000,[1] seeking authorization to perform the New Canada Road MLS Relocation Project in Shelby County, Tennessee. Specifically, Texas Gas requests to perform a miscellaneous rearrangement project involving the offset replacement of: (i) Two segments of existing 26-inch-diameter natural gas pipelines (Main Line System (MLS) 26–1 and MLS 26–2), (ii) one segment of 30-inch-diameter natural gas pipeline (MLS 30–1), and (iii) one segment of 36-inch-diameter natural gas pipeline (MLS 36–1) where they cross Canada Road in Shelby County, Tennessee. Texas Gas is proposing this Project in response to the Tennessee Department of Transportation New Canada Road Project and the estimated cost of the project is $15 million, all as more fully set forth in the request which is on file with the Commission and open to public inspection.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://ferc.gov*) using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. At this time, the Commission has suspended access to the Commission's Public Reference Room, due to the proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19), issued by the President on March 13, 2020. For assistance, contact the Federal Energy Regulatory Commission at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TYY, (202) 502–8659.

Any questions concerning this application should be directed to Juan Eligio, Jr., Manager of Regulatory Affairs, Texas Gas Transmission, LLC, 9 Greenway Plaza, Houston, Texas 77046, at (713) 479–3480, or by email to *Juan.eligio@bwpipelines.com.* Question may also be directed to Payton Barrientos, Sr. Regulatory Analyst, Texas Gas Transmission, LLC, 9 Greenway Plaza, Houston, Texas 77046, at (713) 479–8157, or by email to *payton.barrientos@bwpipelines.com.*

Public Participation

There are three ways to become involved in the Commission's review of this project: You can file a protest to the project, you can file a motion to intervene in the proceeding, and you can file comments on the project. There is no fee or cost for filing protests, motions to intervene, or comments. The deadline for filing protests, motions to intervene, and comments is 5:00 p.m. Eastern Time on January 7, 2021. How to file protests, motions to intervene, and comments is explained below.

Protests

Pursuant to section 157.205 of the Commission's regulations under the NGA,[2] any person [3] or the Commission's staff may file a protest to the request. If no protest is filed within the time allowed or if a protest is filed and then withdrawn within 30 days after the allowed time for filing a protest, the proposed activity shall be deemed to be authorized effective the day after the time allowed for protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request for authorization will be considered by the Commission.

Protests must comply with the requirements specified in section 157.205(e) of the Commission's regulations,[4] and must be submitted by the protest deadline, which is January 7, 2021. A protest may also serve as a motion to intervene so long as the protestor states it also seeks to be an intervenor.

Interventions

Any person has the option to file a motion to intervene in this proceeding. Only intervenors have the right to request rehearing of Commission orders issued in this proceeding and to subsequently challenge the Commission's orders in the U.S. Circuit Courts of Appeal.

To intervene, you must submit a motion to intervene to the Commission in accordance with Rule 214 of the Commission's Rules of Practice and Procedure [5] and the regulations under the NGA [6] by the intervention deadline for the project, which is January 7, 2021. As described further in Rule 214, your motion to intervene must state, to the extent known, your position regarding the proceeding, as well as your interest in the proceeding. For an individual, this could include your status as a landowner, ratepayer, resident of an impacted community, or recreationist. You do not need to have property directly impacted by the project in order to intervene. For more information about motions to intervene, refer to the FERC website at *https://www.ferc.gov/resources/guides/how-to/intervene.asp.*

All timely, unopposed motions to intervene are automatically granted by operation of Rule 214(c)(1). Motions to intervene that are filed after the intervention deadline are untimely and may be denied. Any late-filed motion to intervene must show good cause for being late and must explain why the time limitation should be waived and provide justification by reference to factors set forth in Rule 214(d) of the Commission's Rules and Regulations. A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies (paper or electronic) of all documents filed by the applicant and by all other parties.

Comments

Any person wishing to comment on the project may do so. The Commission considers all comments received about the project in determining the appropriate action to be taken. To ensure that your comments are timely and properly recorded, please submit your comments on or before January 7, 2021. The filing of a comment alone will not serve to make the filer a party to the

[1] *Texas Gas Transmission Corp., 20 FERC ¶62,417 (1982).*

[2] 18 CFR 157.205.

[3] Persons include individuals, organizations, businesses, municipalities, and other entities. 18 CFR 385.102(d).

[4] 18 CFR 157.205(e).

[5] 18 CFR 385.214.

[6] 18 CFR 157.10.

proceeding. To become a party, you must intervene in the proceeding.

How To File Protests, Interventions, and Comments

There are two ways to submit protests, motions to intervene, and comments. In both instances, please reference the Project docket number CP22–11–000 in your submission.

(1) You may file your protest, motion to intervene, and comments by using the Commission's eFiling feature, which is located on the Commission's website (*www.ferc.gov)* under the link to Documents and Filings. New eFiling users must first create an account by clicking on ''eRegister.'' You will be asked to select the type of filing you are making; first select General'' and then select ''Protest'', ''Intervention'', or ''Comment on a Filing.'' The Commission's eFiling staff are available to assist you at (202) 502–8258 or *FercOnlineSupport@ferc.gov.*

(2) You can file a paper copy of your submission. Your submission must reference the Project docket number CP22–11–000.

To mail via USPS, use the following address: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426.

To mail via any other courier, use the following address: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, Maryland 20852.

Protests and motions to intervene must be served on the applicant either by mail or email (with a link to the document) at: Texas Gas Transmission LLC, 9 Greenwat Plaza, Houston, Texas 77046, or by email to *Juan.eligio@bwpipelines.com* and by email to *Payton.barrientos@bwpipelines.com.* Any subsequent submissions by an intervenor must be served on the applicant and all other parties to the proceeding. Contact information for parties can be downloaded from the service list at the eService link on FERC Online.

Tracking the Proceeding

Throughout the proceeding, additional information about the project will be available from the Commission's Office of External Affairs, at (866) 208–FERC, or on the FERC website at *www.ferc.gov* using the ''eLibrary'' link as described above. The eLibrary link also provides access to the texts of all formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. For more information and to register, go to *www.ferc.gov/docs-filing/esubscription.asp.*

Dated: November 8, 2021.

Kimberly D. Bose,

Secretary.

[FR Doc. 2021–24829 Filed 11–12–21; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP22–13–000]

Florida Gas Transmission Company, LLC; Notice of Request Under Blanket Authorization and Establishing Intervention and Protest Deadline

Take notice that on October 28, 2021, Florida Gas Transmission Company, LLC (FGT), 1300 Main Street, Houston, Texas 77002, filed in the above referenced docket, a prior notice request pursuant to sections 157.205, 157.208, and 157.210 of the Commission's regulations under the Natural Gas Act (NGA) and FGT's blanket certificate issued in Docket No. CP82–553–000, for authorization to increase mainline capacity, and to replace and uprate an Electric Motor Drive (EMD) and related appurtenances on compressor unit 1110 and make minor auxiliary modifications to upgrade existing EMD system controls and auxiliary equipment on compressor unit 1111 under Section 2.55(a) of the Commission's regulations, all at FGT's existing Compressor Station 11 (CS 11) in Mobile County, Alabama.

The proposed modifications at CS 11 will allow FGT to flow natural gas from west to east, and transport incremental interstate gas from an existing receipt point in George County, Mississippi, to an existing delivery point in Escambia County, Alabama. The proposed project is designed primarily to meet the demand for an additional 100,000 million British Thermal Units per day (MMBtu/d) of natural gas transportation to be delivered to Florida Power & Light Company (FPL), d/b/a Gulf Power Company (Gulf Power), in FGT's Western Division in the Alabama Gulf Coast natural gas market, all as more fully set forth in the application, which is on file with the Commission and open to public inspection.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://ferc.gov*) using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. At this time, the Commission has suspended access to the Commission's Public Reference Room, due to the proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19), issued by the President on March 13, 2020. For assistance, contact FERC at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TYY, (202) 502–8659.

Any questions regarding this prior notice request should be directed to Blair Lichtenwalter, Senior Director, Certificates, Florida Gas Transmission Company, LLC, 1300 Main Street, P.O. Box 4967, Houston, Texas 77210–4967, at (713) 989–2605, or by email to *Blair.Lichtenwalter@energytransfer.com.*

Public Participation

There are three ways to become involved in the Commission's review of this project: You can file a protest to the project, you can file a motion to intervene in the proceeding, and you can file comments on the project. There is no fee or cost for filing protests, motions to intervene, or comments. The deadline for filing protests, motions to intervene, and comments is 5:00 p.m. Eastern Time on January 7, 2022. How to file protests, motions to intervene, and comments is explained below.

Protests

Pursuant to section 157.205 of the Commission's regulations under the NGA,[1] any person [2] or the Commission's staff may file a protest to the request. If no protest is filed within the time allowed or if a protest is filed and then withdrawn within 30 days after the allowed time for filing a protest, the proposed activity shall be deemed to be authorized effective the day after the time allowed for protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request for authorization will be considered by the Commission.

Protests must comply with the requirements specified in section

[1] 18 CFR 157.205.

[2] Persons include individuals, organizations, businesses, municipalities, and other entities. 18 CFR 385.102(d).

157.205(e) of the Commission's regulations,[3] and must be submitted by the protest deadline, which is January 7, 2022. A protest may also serve as a motion to intervene so long as the protestor states it also seeks to be an intervenor.

Interventions

Any person has the option to file a motion to intervene in this proceeding. Only intervenors have the right to request rehearing of Commission orders issued in this proceeding and to subsequently challenge the Commission's orders in the U.S. Circuit Courts of Appeal.

To intervene, you must submit a motion to intervene to the Commission in accordance with Rule 214 of the Commission's Rules of Practice and Procedure[4] and the regulations under the NGA[5] by the intervention deadline for the project, which is January 7, 2022. As described further in Rule 214, your motion to intervene must state, to the extent known, your position regarding the proceeding, as well as your interest in the proceeding. For an individual, this could include your status as a landowner, ratepayer, resident of an impacted community, or recreationist. You do not need to have property directly impacted by the project in order to intervene. For more information about motions to intervene, refer to the FERC website at *https://www.ferc.gov/resources/guides/how-to/intervene.asp.*

All timely, unopposed motions to intervene are automatically granted by operation of Rule 214(c)(1). Motions to intervene that are filed after the intervention deadline are untimely and may be denied. Any late-filed motion to intervene must show good cause for being late and must explain why the time limitation should be waived and provide justification by reference to factors set forth in Rule 214(d) of the Commission's Rules and Regulations. A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies (paper or electronic) of all documents filed by the applicant and by all other parties.

Comments

Any person wishing to comment on the project may do so. The Commission considers all comments received about the project in determining the appropriate action to be taken. To ensure that your comments are timely and properly recorded, please submit your comments on or before January 7, 2022. *The filing of a comment alone will not serve to make the filer a party to the proceeding.* To become a party, you must intervene in the proceeding.

How To File Protests, Interventions, and Comments

There are two ways to submit protests, motions to intervene, and comments. In both instances, please reference the Project docket number CP22–13–000 in your submission.

(1) You may file your protest, motion to intervene, and comments by using the Commission's *eFiling* feature, which is located on the Commission's website (*www.ferc.gov*) under the link to *Documents and Filings.* New eFiling users must first create an account by clicking on ''*eRegister.*'' You will be asked to select the type of filing you are making; first select ''General'' and then select ''Protest'', ''Intervention'', or ''Comment on a Filing''; or[6]

(2) You can file a paper copy of your submission by mailing it to the address below.[7] Your submission must reference the Project docket number CP22–13–000. Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426.

The Commission encourages electronic filing of submissions (option 1 above) and has eFiling staff available to assist you at (202) 502–8258 or *FercOnlineSupport@ferc.gov.*

Protests and motions to intervene must be served on the applicant either by mail at: 1300 Main Street, P.O. Box 4967, Houston, Texas 77210–4967, or email (with a link to the document) at: *Blair.Lichtenwalter@energytransfer.com.* Any subsequent submissions by an intervenor must be served on the applicant and all other parties to the proceeding. Contact information for parties can be downloaded from the service list at the eService link on FERC Online.

Tracking the Proceeding

Throughout the proceeding, additional information about the project will be available from the Commission's Office of External Affairs, at (866) 208–FERC, or on the FERC website at *www.ferc.gov* using the ''eLibrary'' link as described above. The eLibrary link also provides access to the texts of all formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. For more information and to register, go to *www.ferc.gov/docs-filing/esubscription.asp.*

Dated: November 8, 2021.

Kimberly D. Bose,

Secretary.

[FR Doc. 2021–24830 Filed 11–12–21; 8:45 am]

BILLING CODE 6717–01–P

[3] 18 CFR 157.205(e).

[4] 18 CFR 385.214.

[5] 18 CFR 157.10.

[6] Additionally, you may file your comments electronically by using the eComment feature, which is located on the Commission's website at *www.ferc.gov* under the link to Documents and Filings. Using eComment is an easy method for interested persons to submit brief, text-only comments on a project.

[7] Hand-delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 3777–011]

Town of Rollinsford, New Hampshire; Notice of Technical Meeting

a. *Date and Time of Meeting:* November 15, 2021 at 2:00 p.m. Eastern Standard Time via Conference Call.

b. *FERC Contact:* Bill Connelly at *william.connelly@ferc.gov* or (202) 502–8587

c. *Purpose of Meeting:* On August 23, 2021, Commission staff issued the Environmental Assessment (EA) for the Town of Rollinsford, New Hampshire's (Town) Rollinsford Hydroelectric Project No. 3777 (project). On October 19, 2021, the U.S. Fish and Wildlife Service (FWS) requested a meeting to discuss its recommendations to protect the federally threatened northern long-eared bat (NLEB) and to require the Town to notify resource agencies and the Commission of any activity that may affect a federally listed species in a manner not considered in a license. Commission staff is meeting with the Town, FWS, and other interested participants via conference call, to discuss the issues raised by the FWS in its October 19, 2021 letter.

d. Proposed Agenda:

(1) Introduction of participants;

(2) Commission staff explain the purpose of the meeting;

(3) Participants discuss the following recommendations filed by the U.S. Department of the Interior on June 25, 2020:

• Implement a protocol to avoid adverse effects on the NLEB by

undertaking one of the following measures: avoid any tree removal activities associated with the operation or maintenance of the Project between April 1 and October 1, or employ a qualified biologist to conduct bat exit surveys to determine if bats are utilizing potential roost trees (*i.e.,* trees greater than 3 inches diameter breast height) slated to be removed. If no bats are observed during the exit surveys, the tree(s) may be removed within 24 hours;

• Notify the agencies and the Commission of any activity that may affect a federally listed species in a manner not considered in the new license; and

(4) Participants discuss issue resolution and follow-up actions.

e. A summary of the meeting will be prepared and filed in the Commission's public file for the project.

f. All local, state, and federal agencies, Indian tribes, and other interested parties are invited to participate by phone. If interested, please contact Bill Connelly at *william.connelly@ferc.gov* or (202) 502–8587, by November 12, 2021, to receive the conference call number and access code.

Dated: October 29, 2021.

Kimberly D. Bose,

Secretary.

[FR Doc. 2021–24760 Filed 11–12–21; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: PR21–59–001.
Applicants: Arcadia Gas Storage, LLC.
Description: Submits tariff filing per 284.123(b),(e)/: MBR Authority Info Notice, Compliance Dkt. No. PR21–59–000 to be effective N/A.
Filed Date: 11/5/21.
Accession Number: 20211105–5193.
Comments/Protests Due: 5 p.m. ET 11/26/2021.

Docket Numbers: PR22–3–000.
Applicants: Permian Highway Pipeline LLC.
Description: Submits tariff filing per 284.123(b),(e)/: PHP Fuel Filing—Resubmittal to be effective 10/1/2021 under PR22–3 Filing.
Filed Date: 11/1/2021.
Accession Number: 20211101–5005.
Comments/Protests Due: 5 p.m. ET 11/22/2021.

Docket Numbers: RP21–100–005.
Applicants: National Grid, LNG, LLC.
Description: National Grid LNG, LLC submits tariff filing per 154 203 2021–10–29 Compliance filing to implement Settlement Tariff Sheets to be effective 5/1/2021.
Filed Date: 10/29/21.
Accession Number: 20211029–5212.
Comment Date: 11/12/21.

Docket Numbers: RP22–189–000.
Applicants: Gulf South Pipeline Company, LLC.
Description: § 4(d) Rate Filing: Housekeeping Change to Section 6.21.13 to be effective 12/6/2021.
Filed Date: 11/5/21.
Accession Number: 20211105–5077.
Comment Date: 5 p.m. ET 11/17/21.

Docket Numbers: RP22–190–000.
Applicants: East Tennessee Natural Gas, LLC.
Description: § 4(d) Rate Filing: Negotiated Rates—Nov 2021 Cleanup to be effective 12/5/2021.
Filed Date: 11/5/21.
Accession Number: 20211105–5100.
Comment Date: 5 p.m. ET 11/17/21.

Docket Numbers: RP22–191–000.
Applicants: B–R Pipeline, LLC.
Description: Compliance filing: Order No. 587–Z Compliance Filing to be effective 6/1/2022.
Filed Date: 11/5/21.
Accession Number: 20211105–5101.
Comment Date: 5 p.m. ET 11/17/21.

Docket Numbers: RP22–192–000.
Applicants: Eastern Shore Natural Gas Company.
Description: Compliance filing: NAESB Order 587–Z Version 3.2: Compliance Filing to be effective 6/1/2022.
Filed Date: 11/5/21.
Accession Number: 20211105–5161.
Comment Date: 5 p.m. ET 11/17/21.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

Filings in Existing Proceedings

Docket Numbers: RP21–1188–002.
Applicants: Texas Eastern Transmission, LP.
Description: Compliance filing: TETLP Ministerial Compliance Filing to be effective 11/1/2021.
Filed Date: 11/5/21.
Accession Number: 20211105–5104.
Comment Date: 5 p.m. ET 11/17/21.

Any person desiring to protest in any the above proceedings must file in accordance with Rule 211 of the Commission's Regulations (18 CFR 385.211) on or before 5:00 p.m. Eastern time on the specified comment date.

The filings are accessible in the Commission's eLibrary system (*https://elibrary.ferc.gov/idmws/search/fercgensearch.asp*) by querying the docket number.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: November 8, 2021.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2021–24852 Filed 11–12–21; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER22–353–000]

Indra Power Business MI, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Indra Power Business MI, LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is November 29, 2021.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with internet access

who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically may mail similar pleadings to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426. Hand delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://www.ferc.gov*) using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. At this time, the Commission has suspended access to the Commission's Public Reference Room, due to the proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19), issued by the President on March 13, 2020. For assistance, contact the Federal Energy Regulatory Commission at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TYY, (202) 502–8659.

Dated: November 8, 2021.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2021–24853 Filed 11–12–21; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2021–0513; FRL–8830–02–OCSPP]

Cancellation Order for Certain Pesticide Registrations and Amendments To Terminate Uses

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This notice announces EPA's order for the cancellations and amendments to terminate uses, voluntarily requested by the registrants and accepted by the Agency, of the products listed in Table 1 and Table 2 of Unit II, pursuant to the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA). This cancellation order follows a September 2, 2021, **Federal Register** Notice of Receipt of Requests from the registrants listed in Table 3 of Unit II to voluntarily cancel and amend to terminate uses of these product registrations. In the September 2, 2021, notice, EPA indicated that it would issue an order implementing the cancellations and amendments to terminate uses, unless the Agency received substantive comments within the 30-day comment period that would merit its further review of these requests, or unless the registrants withdrew their requests. The Agency did not receive any comments on the notice. Further, the registrants did not withdraw their requests. Accordingly, EPA hereby issues in this notice a cancellation order granting the requested cancellations and amendments to terminate uses. Any distribution, sale, or use of the products subject to this cancellation order is permitted only in accordance with the terms of this order, including any existing stocks provisions.

DATES: The cancellations and amendments are effective November 15, 2021.

FOR FURTHER INFORMATION CONTACT: Christopher Green, Registration Division (7502P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001; telephone number: (202) 566–2707; email address: *green.christopher@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

This action is directed to the public in general and may be of interest to a wide range of stakeholders including environmental, human health, and agricultural advocates; the chemical industry; pesticide users; and members of the public interested in the sale, distribution, or use of pesticides. Since others also may be interested, the Agency has not attempted to describe all the specific entities that may be affected by this action.

B. How can I get copies of this document and other related information?

The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2021–0513, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW, Washington, DC 20460–0001. 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 OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

Due to the public health concerns related to COVID–19, the EPA Docket Center (EPA/DC) and Reading Room is closed to visitors with limited exceptions. The staff continues to provide remote customer service via email, phone, and webform. For the latest status information on EPA/DC services and docket access, visit *https://www.epa.gov/dockets.*

II. What action is the Agency taking?

This notice announces the cancellations and amendments to terminate uses, as requested by registrants, of products registered under FIFRA section 3 (7 U.S.C. 136a). These registrations are listed in sequence by registration number in Tables 1 and 2 of this unit.

TABLE 1—PRODUCT CANCELLATIONS

Registration No.	Company No.	Product name	Active ingredients
4–459	4	Bonide Captan Wettable	Captan.
100–1343	100	Pulsar Herbicide	Fluroxypyr-meptyl & Dicamba, diglycolamine salt.
279–3027	279	Ammo 2.5 EC Insecticide	Cypermethrin.
279–3070	279	Cynoff WSP Insecticide	Cypermethrin.
279–3591	279	Statement Herbicide	Metolachlor & Sodium salt of fomesafen.
499–371	499	Whitmire PT 120 XLO Sumithrin Contact Insecticide.	Phenothrin.

TABLE 1—PRODUCT CANCELLATIONS—Continued

Registration No.	Company No.	Product name	Active ingredients
499–376	499	Whitmire PT 1810 Total Release Insecticide	Bifenthrin.
499–443	499	Whitmire TC 161 Injection System	Prallethrin & Cyfluthrin.
499–471	499	Whitmire Micro-Gen TC200 Injection System	Prallethrin & lambda-Cyhalothrin.
499–485	499	TC 218	Cyfluthrin.
499–489	499	TC 62	Cyfluthrin.
499–523	499	TC 260	Cyfluthrin.
499–538	499	TC 130 Gen II	Cyfluthrin.
1381–188	1381	Battery 2.5 EC	Cypermethrin.
2693–212	2693	Super Epoxycop with Irgarol-Blue	1,3,5-Triazine-2,4-diamine, N-cyclopropyl-N′-(1,1-dimethylethyl)-6-(methylthio)- & Cuprous oxide.
5383–223	5383	Troy EX2407	1,2-Benzisothiazolin-3-one & Ziram.
7969–343	7969	Cyfluthrin Encapsulated Residual Insecticide Spray.	Cyfluthrin.
7969–361	7969	Priaxor D Fungicide	Tetraconazole; Fluxapyroxad & Pyraclostrobin.
8622–81	8622	Stabilized Bromine Solution	Sulfamic acid, bromo-, monosodium salt.
34704–884	34704	Bifenthrin 7 T&O	Bifenthrin.
34704–888	34704	Bifenthrin 7.9% FL Nursery Insecticide/Miticide.	Bifenthrin.
34704–899	34704	PMN HG	Permethrin.
34704–919	34704	Bisect Nursery Granular Insecticide	Bifenthrin.
34704–925	34704	Termethrin 3.2 Termiticide/Insecticide (Alternate).	Permethrin.
34704–956	34704	Bisect CG Granules	Bifenthrin.
34704–957	34704	Bisect G (Alternate)	Bifenthrin.
34704–963	34704	Covert Termiticide/Insecticide	Permethrin.
34704–977	34704	LPI Metolachlor	Metolachlor.
34704–1073	34704	LPI S-Metolachlor Herbicide	S-Metolachlor.
34704–1027	34704	Permethrin Cutworm Bait	Permethrin.
60061–94	60061	Pettit Marine Paint Ultima SR Ablative Dual Biocide Antifouling Bottom Paint.	Cuprous oxide & 1,3,5-Triazine-2,4-diamine, N-cyclopropyl-N′-(1,1-dimethylethyl)-6-(methylthio)-.
60061–110	60061	Petit Marine Paint SR–21 Fresh Water Antifouling.	1,3,5-Triazine-2,4-diamine, N-cyclopropyl-N′-(1,1-dimethylethyl)-6-(methylthio)-.
60061–111	60061	Copper Powder 1921	Copper as elemental.
60061–117	60061	Pettit Marine Paint Ultima SR Antifouling Paint.	1,3,5-Triazine-2,4-diamine, N-cyclopropyl-N′-(1,1-dimethylethyl)-6-(methylthio)- & Cuprous oxide.
60061–136	60061	Pettit Hydrocoat SR Dual-Biocide Ablative Antifouling.	Cuprous oxide & 1,3,5-Triazine-2,4-diamine, N-cyclopropyl-N′-(1,1-dimethylethyl)-6-(methylthio)-.
60061–141	60061	Pettit Hydrocoat Pro SR Dual-Biocide Ablative Antifouling Paint.	1,3,5-Triazine-2,4-diamine, N-cyclopropyl-N′-(1,1-dimethylethyl)-6-(methylthio)- & Cuprous oxide.
62719–427	62719	Dimension 1EC Turf Herbicide	Dithiopyr.
62719–468	62719	Dimension Ultra 2SC	Dithiopyr.
83222–7	83222	Cyper G–AG 2.5 EC Insecticide	Cypermethrin.
83222–30	83222	Clethodim 2 EC Herbicide	Clethodim.
84229–18	84229	Tide Technical Tebuconazole	Tebuconazole.
AL–060006	34704	Permethrin Insecticide	Permethrin.
GA–060005	34704	Permethrin Insecticide	Permethrin.
ID–060017	34704	Stealth Herbicide	Pendimethalin.
ID–060020	34704	Stealth Herbicide	Pendimethalin.
MA–170001	34704	Intensity Post-Emergence Grass Herbicide	Clethodim.
WA–160001	90924	Formaldehyde Solution 37	Formaldehyde.

TABLE 2—PRODUCT REGISTRATION AMENDMENTS TO TERMINATE USES

Registration No.	Company No.	Product name	Active ingredient	Uses to be terminated
270–300	270	Equicare Flysect Super-7 Repellent Spray.	Stabilene; MGK 326; MGK 264; Piperonyl butoxide; Pyrethrins & Permethrin.	On dogs.
19713–235	19713	Drexel Captan 50W	Captan	Home and Garden Sublabel.
19713–362	19713	Drexel 80% Captan	Captan	Home and Garden Sublabel.
19713–385	19713	Drexel 80% Kaptan	Captan	Home and Garden Sublabel.
19713–405	19713	Drexel Captan 80 WDF	Captan	Home and Garden Sublabel.
19713–646	19713	Drexel Captan 50W Fungicide.	Captan	Home and Garden Sublabel.
19713–652	19713	Drexel Captan 80 WDG	Captan	Home and Garden Sublabel.
47371–146	47371	HS–420 (10%) Water Treatment Microbicide.	1-Decanaminium, N-decyl-N,N-dimethyl-, chloride.	Directions for use for sanitization of food processing equipment and other hard surfaces in food contact locations.

TABLE 2—PRODUCT REGISTRATION AMENDMENTS TO TERMINATE USES—Continued

Registration No.	Company No.	Product name	Active ingredient	Uses to be terminated
47371–164	47371	Formulation HS–1210 Disinfectant/Sanitizer (50%).	Alkyl* dimethyl benzyl ammonium chloride. *(50%C14, 40%C12, 10%C16) & 1-Decanaminium, N-decyl-N,N-dimethyl-, chloride.	Directions for use for re-circulating water in cooling towers and oil field flood or saltwater disposal systems.
61842–21	61842	Linex® 4L Agricultural Herbicide.	Linuron	Post-harvest; Crop stubble; Fallow Ground; Stale Seedbed.
61842–22	61842	Linuron Technical	Linuron	Terrestrial Non-Cropland; Lupine.
61842–23	61842	Lorox DF Agricultural Herbicide.	Linuron	Corn (field); Potato; Sorghum.
61842–24	61842	Linuron Flake Technical	Linuron	Terrestrial Non-Cropland; Lupine.
61842–32	61842	Linuron Technical	Linuron	Terrestrial Non-Cropland; Lupine.

Table 3 of this unit includes the names and addresses of record for all registrants of the products in Tables 1 and 2 of this unit, in sequence by EPA company number. This number corresponds to the first part of the EPA registration numbers of the products listed above.

TABLE 3—REGISTRANTS OF CANCELLED AND AMENDED PRODUCTS

EPA company No.	Company name and address
4	Bonide Products, LLC, 6301 Sutliff Road, Oriskany, NY 13424.
100	Syngenta Crop Protection, LLC, 410 Swing Road, P.O. Box 18300, Greensboro, NC 27419–8300.
270	Farnam Companies, Inc., 1501 E Woodfield Road, Suite 200 West, Schaumburg, IL 60173.
279	FMC Corporation, 2929 Walnut Street, Philadelphia, PA 19104.
499	BASF Corporation, 26 Davis Drive, P.O. Box 13528, Research Triangle Park, NC 27709–3528.
1381	Winfield Solutions, LLC, P.O. Box 64589, St. Paul, MN 55164–0589.
2693	International Paint, LLC, 6001 Antoine Drive, Houston, TX 77091.
5383	Troy Chemical Corporation, 8 Vreeland Road, Florham Park, NJ 07932.
7969	BASF Corporation, 26 Davis Drive, P.O. Box 13528, Research Triangle Park, NC 27709–3528.
8622	ICL–IP America, Inc., 11636 Huntington Road, Gallipolis Ferry, WV 25515.
19713	Drexel Chemical Company, P.O. Box 13327, Memphis, TN 38113–0327.
34704	Loveland Products, Inc., P.O. Box 1286, Greeley, CO 80632–1286.
47371	H&S Chemicals Division of Lonza, LLC, 412 Mount Kemble Avenue, Morristown, NJ 07960.
60061	Kop-Coat, Inc., 36 Pine Street, Rockaway, NJ 07866.
61842	Tessenderlo Kerley, Inc., Agent Name: Pyxis Regulatory Consulting, Inc., 4110 136th Street Ct. NW, Gig Harbor, WA 98332.
62719	Corteva Agriscience, LLC, 9330 Zionsville Road, Indianapolis, IN 46268.
83222	Winfield Solutions, LLC, 1080 County Rd., F West, MS5705, P.O. Box 64589, St. Paul, MN 55164.
84229	Tide International, USA, Inc., Agent Name: Pyxis Regulatory Consulting, Inc., 4110 136th Street Ct. NW, Gig Harbor, WA 98332.
90924	Championx, LLC, 11177 S Stadium Drive, Sugar Land, TX 77478.

III. Summary of Public Comments Received and Agency Response to Comments

During the public comment period provided, EPA received no comments in response to the September 2, 2021, **Federal Register** notice announcing the Agency's receipt of the requests for voluntary cancellations and amendments to terminate uses of the products listed in Tables 1 and 2 of Unit II.

IV. Cancellation Order

Pursuant to FIFRA section 6(f) (7 U.S.C. 136d(f)(1)), EPA hereby approves the requested cancellations and amendments to terminate uses of the registrations identified in Tables 1 and 2 of Unit II. Accordingly, the Agency hereby orders that the product registrations identified in Tables 1 and 2 of Unit II are canceled and amended to terminate the affected uses. The effective date of the cancellations that are subject of this notice is November 15, 2021. Any distribution, sale, or use of existing stocks of the products identified in Tables 1 and 2 of Unit II in a manner inconsistent with any of the provisions for disposition of existing stocks set forth in Unit VI will be a violation of FIFRA.

V. What is the Agency's authority for taking this action?

Section 6(f)(1) of FIFRA (7 U.S.C. 136d(f)(1)) provides that a registrant of a pesticide product may at any time request that any of its pesticide registrations be canceled or amended to terminate one or more uses. FIFRA further provides that, before acting on the request, EPA must publish a notice of receipt of any such request in the **Federal Register**. Thereafter, following the public comment period, the EPA Administrator may approve such a request. The notice of receipt for this action was published for comment in the **Federal Register** of September 2, 2021 (86 FR 49327) (FRL–8830–01–OSCPP). The comment period closed on October 4, 2021.

VI. Provisions for Disposition of Existing Stocks

Existing stocks are those stocks of registered pesticide products which are currently in the United States and which were packaged, labeled, and released for shipment prior to the effective date of the action. The existing stocks provision for the products subject to this order is as follows.

For the voluntary cancellations, the registrants may continue to sell and distribute existing stocks of products listed in Table 1 until November 15,

2022, which is 1 year after publication of this cancellation order in the **Federal Register**. Thereafter, the registrants are prohibited from selling or distributing products listed in Table 1 of Unit II, except for export in accordance with FIFRA section 17 (7 U.S.C. 136o) or for proper disposal.

Now that EPA has approved product labels reflecting the requested amendments to terminate uses, registrants are permitted to sell or distribute products listed in Table 2 of Unit II under the previously approved labeling until May 15, 2023, a period of 18 months after publication of the cancellation order in this **Federal Register**, unless other restrictions have been imposed. Thereafter, registrants will be prohibited from selling or distributing the products whose labels include the terminated uses identified in Table 2 of Unit II, except for export consistent with FIFRA section 17 or for proper disposal.

Persons other than the registrant may sell, distribute, or use existing stocks of canceled products and products whose labels include the terminated uses until supplies are exhausted, provided that such sale, distribution, or use is consistent with the terms of the previously approved labeling on, or that accompanied, the canceled products and terminated uses.

Authority: 7 U.S.C. 136 *et seq.*

Dated: November 5, 2021.

Catherine Aubee,

Acting Director, Registration Division, Office of Pesticide Programs.

[FR Doc. 2021–24800 Filed 11–12–21; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2021–0050; FRL–8963–01–OCSPP]

Pesticide Emergency Exemptions; Agency Decisions and State and Federal Agency Crisis Declarations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has granted emergency exemptions under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) for use of pesticides as listed in this notice. The exemptions were granted during the period April 1, 2021 to June 30, 2021 to control unforeseen pest outbreaks.

FOR FURTHER INFORMATION CONTACT: Marietta Echeverria, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001; main telephone number: (703) 305–7090; email address: *RDFRNotices@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

If you have any questions regarding the applicability of this action to a particular entity, consult the person listed at the end of the emergency exemption.

B. How can I get copies of this document and other related information?

The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2021–0050, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW, Washington, DC 20460–0001.

Due to the public health concerns related to COVID–19, the EPA Docket Center (EPA/DC) and Public Reading Room is closed to visitors with limited exceptions. The staff continues to provide remote customer service via email, phone, and webform. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *https://www.epa.gov/dockets.*

II. Background

EPA has granted emergency exemptions to the following State and Federal agencies. The emergency exemptions may take the following form: Crisis, public health, quarantine, or specific.

Under FIFRA section 18 (7 U.S.C. 136p), EPA can authorize the use of a pesticide when emergency conditions exist. Authorizations (commonly called emergency exemptions) are granted to State and Federal agencies and are of four types:

1. A ''specific exemption'' authorizes use of a pesticide against specific pests on a limited acreage in a particular State. Most emergency exemptions are specific exemptions.

2. ''Quarantine'' and ''public health'' exemptions are emergency exemptions issued for quarantine or public health purposes. These are rarely requested.

3. A ''crisis exemption'' is initiated by a State or Federal agency (and is confirmed by EPA) when there is insufficient time to request and obtain EPA permission for use of a pesticide in an emergency.

EPA may deny an emergency exemption: If the State or Federal agency cannot demonstrate that an emergency exists, if the use poses unacceptable risks to the environment, or if EPA cannot reach a conclusion that the proposed pesticide use is likely to result in ''a reasonable certainty of no harm'' to human health, including exposure of residues of the pesticide to infants and children.

If the emergency use of the pesticide on a food or feed commodity would result in pesticide chemical residues, EPA establishes a time-limited tolerance meeting the ''reasonable certainty of no harm standard'' of the Federal Food, Drug, and Cosmetic Act (FFDCA).

In this document: EPA identifies the State or Federal agency granted the exemption, the type of exemption, the pesticide authorized and the pests, the crop or use for which authorized, number of acres (if applicable), and the duration of the exemption. EPA also gives the **Federal Register** citation for the time-limited tolerance, if any.

III. Emergency Exemptions

A. U.S. States and Territories

Arkansas

Department of Agriculture

Specific exemption: EPA authorized the use of fluridone on a maximum of 5,000 acres of peanut to control herbicide-resistant Palmer amaranth (*Amaranthus palmeri*). A time-limited tolerance in connection with this action will be established in 40 CFR 180.420(b). The authorization for this use is effective May 7, 2021 to August 1, 2021.

California

Department of Pesticide Regulation

Specific exemption: EPA authorized the use of bifenthrin on a maximum of 18,000 acres of pomegranate to control leaffooted plant bug. A time-limited tolerance in connection with a past action has been established in 40 CFR 180.442(b). The authorization for this use is effective June 21, 2021 to January 15, 2022.

Colorado

Department of Agriculture

Specific exemption: EPA authorized the use of acifluorfen on a maximum of 5,500 acres of sugar beets for postemergence control of glyphosate-resistant Palmer amaranth pigweed (*Amaranthus palmeri*). Time-limited tolerances in connection with this action will be established in 40 CFR 180.383(b). The authorization for this use is effective June 1, 2021 to July 31, 2021.

Georgia

Department of Agriculture

Public Health Exemption: EPA authorized the use of Benzene, 1-(1,1-dimethylethyl)-4-ethenyl-, polymer with ethenylbenzene and 2-methyl-1,3-butadiene, sulfonated, CAS 1637665–77–0 (referred to as BiaXam polymer), for supplemental residual control of Severe Acute Respiratory Syndrome Coronavirus 2 (SARS–CoV–2) on hard, nonporous, nonfood-contact surfaces in Delta Air Lines airplanes and airport facilities in Georgia. Because the request proposed use of a new chemical (an active ingredient not contained in any currently registered pesticide), in accordance with the requirements at 40 CFR 166.24, a notice of receipt published in the **Federal Register** on February 9, 2021 (86 FR 8784) (FRL–10019–60) with the public comment period closing on February 24, 2021. The authorization for this use is effective April 21, 2021 to April 21, 2022.

Hawaii

Department of Agriculture

Specific exemption: EPA authorized the use of fluxapyroxad and pyraclostrobin on a maximum of 8,000 acres of coffee to control coffee leaf rust (*Hemileia vastatrix*). Import tolerances in connection with prior registration actions have been established in 40 CFR 180.166 for fluxapyroxad and 40 CFR 180.582 for pyraclostrobin to support this action. The authorization for this use is effective May 19, 2021 to May 19, 2022.

Michigan

Department of Agriculture and Rural Development

Specific exemption: EPA authorized the use of acifluorfen on a maximum of 48,000 acres of sugar beets for postemergence control of invasive *Amaranthus* (pigweed) spp., glyphosate-resistant-waterhemp (*Amaranthus tuberculatus*), and Palmer amaranth (*Amaranthus palmeri*). Time-limited tolerances in connection with this action will be established in 40 CFR 180.383(b). The authorization for this use is effective June 1, 2021 to July 31, 2021.

Minnesota

Department of Agriculture

Specific exemption: EPA authorized the use of acifluorfen on a maximum of 96,000 acres of sugar beets for postemergence control of glyphosate-resistant waterhemp (*Amaranthus tuberculatus*). Time-limited tolerances in connection with this action will be established in 40 CFR 180.383(b). Effective June 1, 2021 to July 31, 2021.

Public Health Exemption: EPA authorized the use of Benzene, 1-(1,1-dimethylethyl)-4-ethenyl-, polymer with ethenylbenzene and 2-methyl-1,3-butadiene, sulfonated, CAS 1637665–77–0 (referred to as BiaXam polymer), for supplemental residual control of Severe Acute Respiratory Syndrome Coronavirus 2 (SARS–CoV–2) on hard, nonporous, nonfood-contact surfaces in Delta Air Lines airplanes and airport facilities in Minnesota. Because the request proposed use of a new chemical (an active ingredient not contained in any currently registered pesticide), in accordance with the requirements at 40 CFR 166.24, a notice of receipt published in the **Federal Register** on February 9, 2021 (86 FR 8784) (FRL–10019–60) with the public comment period closing on February 24, 2021. The authorization for this use is effective April 21, 2021 to April 21, 2022.

Missouri

Department of Agriculture

Specific exemption: EPA authorized the use of fluridone on a maximum of 4,000 acres of peanut to control herbicide-resistant Palmer amaranth (*Amaranthus palmeri*). A time-limited tolerance in connection with this action will be established in 40 CFR 180.420(b). The authorization for this use is effective May 7, 2021 to August 1, 2021.

Nebraska

Department of Agriculture

Specific exemption: EPA authorized the use of acifluorfen on a maximum of 11,000 acres of sugar beets for postemergence control of glyphosate-resistant Palmer amaranth pigweed (*Amaranthus palmeri*). Time-limited tolerances in connection with this action will be established in 40 CFR 180.383(b). The authorization for this use is effective June 1, 2021 to July 31, 2021.

New York

Department of Environmental Conservation

Public Health Exemptions: EPA authorized the use of peroxyacetic acid and hydrogen peroxide to treat regulated medical waste potentially contaminated with the causal agent of COVID–19, the Severe Acute Respiratory Syndrome Coronavirus 2 (SARS–CoV–2). The authorization for this use is effective June 17, 2021 to June 17, 2022.

North Dakota

Department of Agriculture

Specific exemption: EPA authorized the use of acifluorfen on a maximum of 34,000 acres of sugar beets for postemergence control of glyphosate resistant waterhemp (*Amaranthus tuberculatus*). Time-limited tolerances in connection with this action will be established in 40 CFR 180.383(b). The authorization for this use is effective June 1, 2021 to July 31, 2021.

Utah

Department of Agriculture and Food

Public Health Exemptions: EPA authorized the use of Benzene, 1-(1,1-dimethylethyl)-4-ethenyl-, polymer with ethenylbenzene and 2-methyl-1,3-butadiene, sulfonated, CAS 1637665–77–0 (referred to as BiaXam polymer), for supplemental residual control of Severe Acute Respiratory Syndrome Coronavirus 2 (SARS–CoV–2) on hard, nonporous, nonfood-contact surfaces in Delta Air Lines airplanes and airport facilities in Utah. Because the request proposed use of a new chemical (an active ingredient not contained in any currently registered pesticide), in accordance with the requirements at 40 CFR 166.24, a notice of receipt published in the **Federal Register** on February 9, 2021 (86 FR 8784) (FRL–10019–60) with the public comment period closing on February 24, 2021. The authorization for this use is effective April 21, 2021 to April 21, 2022.

Authority: 7 U.S.C. 136 *et seq.*

Dated: October 29, 2021.

Marietta Echeverria,

Acting Director, Registration Division, Office of Pesticide Programs.

[FR Doc. 2021–24787 Filed 11–12–21; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9225–01–OA]

Request for Nominations of Candidates for the Clean Air Scientific Advisory Committee (CASAC) Ozone Panel

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Environmental Protection Agency (EPA) Science Advisory Board (SAB) Staff Office requests public nominations of scientific experts for the CASAC Ozone Panel. This panel will provide advice through the chartered CASAC on policy-relevant science for the agency's reconsideration of the Ozone National Ambient Air Quality Standards (NAAQS).

DATES: Nominations should be submitted by December 6, 2021 per the instructions below.

FOR FURTHER INFORMATION CONTACT: Any member of the public wishing further information regarding this Notice and Request for Nominations may contact Mr. Aaron Yeow, Designated Federal Officer (DFO), SAB Staff Office, by telephone at (202) 564–2050 or via email at *yeow.aaron@epa.gov*. General information concerning the CASAC can be found on the following website: *https://casac.epa.gov*.

SUPPLEMENTARY INFORMATION:

Background: The CASAC was established pursuant to the Clean Air Act (CAA) Amendments of 1977, codified at 42 U.S.C. 7409(d)(2), to review air quality criteria and NAAQS and recommend to the EPA Administrator any new NAAQS and revisions of existing criteria and NAAQS as may be appropriate. The CASAC shall also: advise the EPA Administrator of areas in which additional knowledge is required to appraise the adequacy and basis of existing, new, or revised NAAQS; describe the research efforts necessary to provide the required information; advise the EPA Administrator on the relative contribution to air pollution concentrations of natural as well as anthropogenic activity; and advise the EPA Administrator of any adverse public health, welfare, social, economic, or energy effects which may result from various strategies for attainment and maintenance of such NAAQS. As amended, 5 U.S.C., App. Section 109(d)(1) of the Clean Air Act (CAA) requires that EPA carry out a periodic review and revision, as appropriate, of the air quality criteria and the NAAQS for the six ''criteria'' air pollutants, including ozone.

The CASAC is a Federal advisory committee chartered under the Federal Advisory Committee Act (FACA). As a Federal Advisory Committee, the CASAC conducts business in accordance with the Federal Advisory Committee Act (FACA) (5 U.S.C. App. 2) and related regulations. The CASAC and the CASAC Ozone Panel will comply with the provisions of FACA and all appropriate SAB Staff Office procedural policies.

EPA has made the determination to reconsider the December 2020 decision to retain the ozone National Ambient Air Quality Standards (NAAQS). These standards were last revised in 2015. The CASAC Ozone Panel will provide advice through the Chartered CASAC on policy-relevant science to support the Agency's reconsideration of the ozone NAAQS.

The CASAC is a Federal advisory committee chartered under the Federal Advisory Committee Act (FACA). As a Federal Advisory Committee, the CASAC conducts business in accordance with the Federal Advisory Committee Act (FACA) (5 U.S.C. App. 2) and related regulations. The CASAC and the CASAC Ozone Panel will comply with the provisions of FACA and all appropriate SAB Staff Office procedural policies.

Request for Nominations: The SAB Staff Office is seeking nominations of nationally and internationally recognized scientists with demonstrated expertise and research in the field of air pollution related to criteria pollutants. For the CASAC Ozone Panel, experts are being sought in the following fields, especially with respect to ozone: Air quality, atmospheric science and chemistry; exposure assessment; toxicology; controlled clinical exposure; epidemiology; biostatistics; risk assessment; ecology, including of forests and terrestrial systems; and effects on welfare and the environment.

Process and Deadline for Submitting Nominations: Any interested person or organization may nominate qualified individuals in the areas of expertise described above. Individuals may self-nominate. Nominations should be submitted in electronic format (preferred) using the online nomination form under ''Public Input on Membership'' on the CASAC web page at *https://casac.epa.gov*. To be considered, all nominations should include the information requested below. EPA values and welcomes diversity. All qualified candidates are encouraged to apply regardless of sex, race, disability or ethnicity. Nominations should be submitted by December 6, 2021.

The following information should be provided on the nomination form: Contact information for the person making the nomination; contact information for the nominee; and the disciplinary and specific areas of expertise of the nominee. Nominees will be contacted by the SABSO and will be asked to provide a recent *curriculum vitae* and a narrative biographical summary that includes: current position, educational background; research activities; sources of research funding for the last two years; and recent service on other national advisory committees or national professional organizations. Persons having questions about the nomination process or the public comment process described below, or who are unable to submit nominations through the CASAC website, should contact the DFO, as identified above. The names and biosketches of qualified nominees identified by respondents to this **Federal Register** notice, and additional experts identified by the SAB Staff Office, will be posted in a List of Candidates on the CASAC website at *https://casac.epa.gov*. Public comments on each List of Candidates will be accepted for 21 days from the date the list is posted. The public will be requested to provide relevant information or other documentation on nominees that the SAB Staff Office should consider in evaluating candidates.

For the EPA SAB Staff Office, a balanced review panel includes candidates who possess the necessary domains of knowledge, the relevant scientific perspectives (which, among other factors, can be influenced by work history and affiliation), and the collective breadth of experience to adequately address the charge. In forming this expert panel, the SAB Staff Office will consider public comments on the List of Candidates, information provided by the candidates themselves, and background information independently gathered by the SAB Staff Office. Selection criteria to be used for panel membership include: (a) Scientific and/or technical expertise, knowledge, and experience (primary factors); (b) availability and willingness

to serve; (c) absence of financial conflicts of interest; (d) absence of an appearance of a lack of impartiality; (e) skills working in committees, subcommittees and advisory panels; and (f) for the panel as a whole, diversity of expertise and viewpoints.

Candidates may be asked to submit the ''Confidential Financial Disclosure Form for Special Government Employees Serving on Federal Advisory Committees at the U.S. Environmental Protection Agency'' (EPA Form 3110–48). This confidential form is required for Special Government Employees (SGEs) and allows EPA to determine whether there is a statutory conflict between that person's public responsibilities as an SGE and private interests and activities, or the appearance of a loss of impartiality, as defined by Federal regulation. The form may be viewed and downloaded through the ''Ethics Requirements for Advisors'' link on the CASAC home page at *https://casac.epa.gov*. This form should not be submitted as part of a nomination.

V Khanna Johnston,

Deputy Director, Science Advisory Board Staff Office.

[FR Doc. 2021–24783 Filed 11–12–21; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPPT–2020–0078; FRL–9169–01–OCSPP]

Agency Information Collection Activities; Proposed Revisions to an Existing Collection, Toxic Chemical Release Reporting; Comment Request

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA), this document announces that EPA is planning to submit the following Information Collection Request (ICR) to the Office of Management and Budget (OMB): ''Toxic Chemical Release Reporting (Revision)'' and identified by ICR No. 2613.04 and OMB Control No. 2070–0212. This ICR is a revision to an existing ICR that is scheduled to expire on March 31, 2024. The existing ICR is being revised ahead of schedule to include potential reporting requirements that may result from EPA's use of other authority under the Emergency Planning and Community Right-to-Know Act (EPCRA) that is not specifically covered by the existing ICR. Before submitting the ICR to OMB for review and approval under the PRA, EPA is soliciting comments on specific aspects of the proposed information collection that is summarized in this document. The ICR and accompanying material are available in the docket for public review and comment.

DATES: Comments must be received on or before January 14, 2022.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPPT–2020–0078, using the Federal eRulemaking Portal at *http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

Due to the public health concerns related to COVID–19, the EPA Docket Center (EPA/DC) is by appointment only. For the latest status information on EPA/DC and docket access, visit *https://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Stephanie Griffin (7410M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001; telephone number: (202) 564–1463; email address: *griffin.stephanie@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. What information is EPA particularly interested in?

Pursuant to PRA section 3506(c)(2)(A), 44 U.S.C. 3506(c)(2)(A), EPA specifically solicits comments and information to enable it to:

1. Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility.

2. Evaluate the accuracy of the Agency's estimates of the burden of the proposed collection of information, including the validity of the methodology and assumptions used.

3. Enhance the quality, utility, and clarity of the information to be collected.

4. Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses. In particular, EPA is requesting comments from very small businesses (those that employ less than 25) on examples of specific additional efforts that EPA could make to reduce the paperwork burden for very small businesses affected by this collection.

II. What information collection activity or ICR does this action apply to?

Title: Toxic Chemical Release Reporting (Revision).

ICR number: 2316.04.

OMB control number: 2070–0212.

ICR status: The existing ICR is currently scheduled to expire on March 31, 2024. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in title 40 of the Code of Federal Regulations (CFR), after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, are displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers for certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: Pursuant to section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA), 42 U.S.C. 11001 *et seq.,* certain facilities that manufacture, process, or otherwise use specified toxic chemicals in amounts above reporting threshold levels as provided in 40 CFR 372.25 must submit annually to EPA reporting forms to the Toxics Release Inventory (TRI). The revisions to this ICR covers the information collection activities associated with the submission of information to TRI pursuant to EPCRA section 313(b)(2), 42 U.S.C. 11023. Under EPCRA section 313(b)(2), the EPA Administrator has the authority to extend TRI reporting requirements to specific facilities that manufacture, process, or otherwise use a TRI-listed toxic chemical, but who are not covered by TRI reporting requirements as described at 40 CFR 372. The Administrator may determine a specific facility warrants TRI reporting on the basis of a chemical's toxicity, the facility's proximity to other facilities that release the chemical or to population centers, the facility's history of releases of the chemical, or other factors that the Administrator deems appropriate. This ICR revision includes discussion of EPA's discretionary authority under EPCRA section

313(b)(2) and outreach to potential stakeholders.

Burden statement: The annual public reporting and recordkeeping burden for this collection of information is 3,615,128 hours. EPA estimates that it will take submitters 35.7 hours to submit a Form R for one chemical and 21.96 hours to submit a Form A for one chemical. Burden is defined in 5 CFR 1320.3(b).

The ICR, which is available in the docket along with other related materials, provides a detailed explanation of the collection activities and the burden estimate that is only briefly summarized here:

Respondents/Affected Entities: Regulations at 40 CFR part 372, subpart B, require facilities that meet all the following criteria to report: The facility has 10 or more full-time employee equivalents (*i.e.,* a total of 20,000 hours worked per year or greater; see 40 CFR 372.3); the facility is included in a North American Industry Classification System (NAICS) Code listed at 40 CFR 372.23 or under Executive Order 13148, Federal facilities regardless of their industry classification; and the facility manufactures (defined to include importing), processes, or otherwise uses any EPCRA section 313 (TRI) chemical in quantities greater than the established thresholds for the specific chemical in the course of a calendar year. Additionally, EPA may exercise its discretionary authority under EPCRA section 313(b)(2) to extend TRI reporting obligations to a facility, even if the facility does not meet the criteria for full-time employees or NAICS codes.

Respondent's obligation to respond: Mandatory, 40 CFR 372.

Estimated total number of potential respondents: 76,534.

Frequency of response: Annual.

Estimated total annual burden hours: 3,615,128 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Estimated total annual costs: $200,205,764 (per year), includes $0 annualized capital or operation & maintenance costs.

III. Are there changes in the estimates from the last approval?

This ICR revision reflects an increase of 3 burden hours per facility in non-reporting burden from the ICR currently approved by OMB and this ICR. This increase reflects the review of the notification and preparation of responses stakeholders may engage in upon receipt of the Agency's notification of its potential application of the discretionary authority under EPCRA section 313(b)(2) to specific facilities. This increase is categorized as a program change.

IV. What is the next step in the process for this ICR?

EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval pursuant to 5 CFR 1320.12. EPA will issue another **Federal Register** document pursuant to 5 CFR 1320.5(a)(1)(iv) to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB. If you have any questions about this ICR or the approval process, please contact the person listed under **FOR FURTHER INFORMATION CONTACT**.

Authority: 44 U.S.C. 3501 *et seq.*

Dated: October 27, 2021.

Michal Freedhoff,

Assistant Administrator, Office of Chemical Safety and Pollution Prevention.

[FR Doc. 2021–24788 Filed 11–12–21; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL ACCOUNTING STANDARDS ADVISORY BOARD

Notice of Issuance of Federal Financial Accounting Standards (SFFAS) 60, Omnibus Amendments 2021: Leases-Related Topics

AGENCY: Federal Accounting Standards Advisory Board.

ACTION: Notice.

SUMMARY: Notice is hereby given that the Federal Accounting Standards Advisory Board (FASAB) has issued Statement of Federal Financial Accounting Standards (SFFAS) 60, *Omnibus Amendments 2021: Leases-Related Topics.*

ADDRESSES: The issuance is available on the FASAB website at *https://fasab.gov/accounting-standards/*. Copies can be obtained by contacting FASAB at (202) 512–7350.

FOR FURTHER INFORMATION CONTACT: Ms. Monica R. Valentine, Executive Director, 441 G Street NW, Suite 1155, Washington, DC 20548, or call (202) 512–7350.

Authority: 31 U.S.C. 3511(d), the Federal Advisory Committee Act, as amended (5 U.S.C. App.), and the FASAB Rules of Procedure, as amended in October 2010.

Dated: November 4, 2021.

Monica R. Valentine,

Executive Director.

[FR Doc. 2021–24866 Filed 11–12–21; 8:45 am]

BILLING CODE P

FEDERAL ACCOUNTING STANDARDS ADVISORY BOARD

Notice of Issuance of TR 20, Implementation Guidance for Leases

AGENCY: Federal Accounting Standards Advisory Board.

ACTION: Notice.

SUMMARY: Notice is hereby given that the Federal Accounting Standards Advisory Board (FASAB) has issued Technical Release (TR) 20, *Implementation Guidance for Leases.*

ADDRESSES: The issuance is available on the FASAB website at *https://fasab.gov/accounting-standards/*. Copies can be obtained by contacting FASAB at (202) 512–7350.

FOR FURTHER INFORMATION CONTACT: Ms. Monica R. Valentine, Executive Director, 441 G Street NW, Suite 1155, Washington, DC 20548, or call (202) 512–7350.

Authority: 31 U.S.C. 3511(d), the Federal Advisory Committee Act, as amended (5 U.S.C. app.), and the FASAB Rules of Procedure, as amended in October 2010.

Dated: November 4, 2021.

Monica R. Valentine,

Executive Director.

[FR Doc. 2021–24869 Filed 11–12–21; 8:45 am]

BILLING CODE P

FEDERAL DEPOSIT INSURANCE CORPORATION

Agency Information Collection Activities: Submission for OMB Review; Comment Request (3064–0200)

AGENCY: Federal Deposit Insurance Corporation (FDIC).

ACTION: 30-Day notice and request for comment.

SUMMARY: The Federal Deposit Insurance Corporation (FDIC) will submit the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection was previously published in the **Federal Register** on August 10, 2021, allowing for a 60-day comment period.

DATES: Comments are encouraged and will be accepted for an additional 30 days until December 15, 2021.

ADDRESSES: Interested parties are invited to submit written comments to the FDIC by any of the following methods:

• *https://www.FDIC.gov/regulations/laws/federal.*

• *Email: comments@fdic.gov.* Include the name and number of the collection in the subject line of the message.

• *Mail:* Manny Cabeza (202–898–3767), Regulatory Counsel, MB–3128, Federal Deposit Insurance Corporation, 550 17th Street NW, Washington, DC 20429.

• *Hand Delivery:* Comments may be hand-delivered to the guard station at the rear of the 17th Street Building (located on F Street), on business days between 7:00 a.m. and 5:00 p.m.

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-Day Review—Open for Public Comments'' or by using the search function.

FOR FURTHER INFORMATION CONTACT: Manny Cabeza, Regulatory Counsel, 202–898–3767, *mcabeza@fdic.gov,* MB–3128, Federal Deposit Insurance Corporation, 550 17th Street NW, Washington, DC 20429.

SUPPLEMENTARY INFORMATION: Proposal to renew the following currently approved collection of information:

1. *Title:* Joint Standards for Assessing Diversity Policies and Practices.

OMB Number: 3064–00200.

Form Number: 2710/05—Diversity Self-Assessment (paper form), 2710/06—Diversity Self-Assessment (electronic form).

Affected Public: Insured state nonmember banks, and insured state savings associations.

Burden Estimate: FDIC is revising the burden estimates associated with this information collection as a result of the update of the electronic version of the reporting form. The update will allow respondents who have previously completed a diversity self-assessment (DSA) to copy and clone their previous submission. This copy/clone capability reduces the reporting burden for returning respondents. However, it does not change the burden for respondents who fill out the electronic form for the first time or respondents who choose an alternative method of assessing their diversity policies and practices. As such, this ICR revises the IC line items to distinguish between the *implementation burden* incurred by first time respondents from the *ongoing burden* incurred by returning respondents. This ICR also updates the respondent count estimates for the other line items in this IC. Finally, this ICR adds a line to cover the burdens of non-material (not responsive) submissions.

In October 2020, the FDIC implemented a copy/clone feature in FID–SA for submissions covering the 2020 reporting period and beyond. This feature allows the respondent to pre-populate a new diversity self-assessment with the information that was previously completed and submitted. In addition, the FDIC Office of Minority and Women Inclusion (OMWI) have identified several submissions that complete the pro forma form but do not provide the FDIC with any material self-assessments. With the addition of these two submission types, there are now five distinct submission types for this IC:

1. *Paper Form Submissions,* which are DSA submissions that use the ''Diversity Self-Assessment of Financial Institutions Regulated by the FDIC'' form and submit the form as an email attachment or via the United States Postal Service;

2. *Electronic Form (Implementation) Submissions,* which are DSA submissions that utilize the online FID–SA application, and the financial institution has not previously submitted a DSA;

3. *Electronic Form (Ongoing) Submissions,* which are DSA submissions that utilize the online FID–SA application and are able to use the copy/clone feature in FID–SA;

4. *Free-Form Submissions,* which are submissions that do not use the ''Diversity Self-Assessment of Financial Institutions Regulated by the FDIC'' form; and

5. *Non-material Submissions,* which are pro forma submissions that do not provide any material self-assessments.

Estimated Number of Respondents and Responses

Responses to this information collection are voluntary and may be submitted by any FDIC-regulated financial institution. As such, potential respondents to this IC are all FDIC-regulated financial institutions. As of December 31, 2020, the FDIC regulates 3,227 insured depository institutions (IDIs). Of these institutions, 2,380 are considered small for the purposes of the Regulatory Flexibility Act (RFA).

Respondents submit a single response per year. To estimate the number of respondents for this ICR, FDIC reviewed and summarized data from historical submissions by FDIC-regulated IDIs covering diversity activities in the reporting periods 2016–2019. Submissions were categorized as a first-time submission if no prior submission was made by the same IDI. Otherwise, the submission was categorized as a repeat submission. FDIC did not categorize 2016 submissions since 2016 was the first year for which the agency has submission data. A summary of these results is provided in Table 1 below:

TABLE 1—OMWI SUBMISSION COUNTS, BY SUBMISSION TYPE AND REPORTING PERIOD

Submission type	2016	2017	2018	2019
All submissions*	95	137	133	152
All submissions, small IDIs**	17	26	26	33
First-time submissions		81	42	38
First-time submissions, small IDIs**		18	13	16
Repeat submissions		56	91	113
Repeat submissions, small IDIs**		8	13	17

Source: FDIC OMWI.

* These counts include two financial institutions (CERTs 20399 in 2016 and 29845 in 2019) that were later found to not be regulated by the FDIC during their respective reporting periods. We include them here to align the table with other OMWI published analyses (available at *https://www.fdic.gov/about/diversity/analysisdsa.html).*

** IDIs are counted as small if they meet the SBA's definition of ''small'' for purposes of RFA as of December 31st in each reporting period.

As Table 1 shows, there were 152 total submissions in 2019, the most recent reporting year. This is an increase of approximately 20 submissions from the previous year. This increase is due to the introduction of the online FID–SA application and an expanded outreach effort by the FDIC to educate and increase awareness about the DSA. The

FDIC expects that submission counts will continue to climb upwards due to continued expanded outreach efforts as well as the introduction of the copy/clone feature to facilitate responses. Based on the historical submission counts and the expected rise in submissions, the FDIC expects it will receive 195 submissions per year with the majority of these submissions using the online FID–SA application. Based on the historical trends of first-time and repeating submissions future expectations, the FDIC anticipates annual respondent counts of 45 Electronic Form (Implementation) and 130 Electronic Form (Ongoing) submissions.[1] In addition, the FDIC anticipates annual counts of five Free-Form Submissions and ten Non-material Submissions.[2] Finally, FDIC recognizes that some IDIs may prefer to continue providing Paper Submissions and anticipate five such submissions per year.

Estimated Hourly Burden

The FDIC estimates that Electronic Form (Implementation) Submissions will take seven hours, the same burden that was recorded in the *Electronic Form* line item in the 2020 ICR. For Electronic Form (Ongoing) Submissions, the FDIC estimates that the copy/clone feature will save respondents an average of four hours per submission, for a net burden of three hours per response. For Non-material Submissions, the FDIC estimates that the pro forma completion of the submission application will take six minutes, or 0.1 hours. The FDIC has reviewed the hourly burden estimates for Paper Submissions and for Free-Form Submissions and found that the estimates from the 2020 ICR remain reasonable and appropriate. Finally, the FDIC estimates that each respondent will incur one hour of burden per year, on average, to disclose a portion of its submission to the public, in a manner reflective of the entity's size and other characteristics.

The estimated annual burden for each submission type, in hours, is the product of the estimated number of respondents, number of responses per respondent per year, and time per response, as summarized in Table 2 below. The total estimated annual burden for this information collection is 100, 106 hours, a reduction of 559 hours from the previously approved ICR. [3]

TABLE 2—SUMMARY OF ESTIMATED ANNUAL BURDEN (OMB NO. 3064–0006)

Information collection description—submission type	Type of burden (obligation to respond)	Frequency of response	Number of respondents	Number of responses per respondent	Hours per response	Annual burden (hours)
Joint Standards for Assessing Diversity Policies and Practices—*Paper Form*.	Reporting (Voluntary)	Annual	5	1	8	40
Joint Standards for Assessing Diversity Policies and Practices—*Electronic Form (Implementation)*.	Reporting (Voluntary)	Annual	45	1	7	315
Joint Standards for Assessing Diversity Policies and Practices—*Electronic Form*. (Ongoing)	Reporting (Voluntary)	Annual	130	1	3	390
Joint Standards for Assessing Diversity Policies and Practices—*Free-Form*.	Reporting (Voluntary)	Annual	5	1	12	60
Joint Standards for Assessing Diversity Policies and Practices—*Non-material*	Reporting (Voluntary)	Annual	10	1	0.1	1
Joint Standards for Assessing Diversity Policies and Practices—*Public Disclosure*	Disclosure (Voluntary)	Annual	195	1	1	195
Total Annual Burden (Hours)						1,001

Source: FDIC.

General Description of Collection

Section 342 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (the Act) required the Office of the Comptroller of the Currency (OCC), Board of Governors of the Federal Reserve System (Board), Federal Deposit Insurance Corporation (FDIC), Bureau of Consumer Financial Protection (CFPB), National Credit Union Administration (NCUA), and Securities and Exchange Commission (SEC) (together, Agencies and separately, Agency) each to establish an Office of Minority and Women Inclusion (OMWI) to be responsible for all matters of the Agency relating to diversity in management, employment, and business activities. The Act also instructed each OMWI Director to develop standards for assessing the diversity policies and practices of entities regulated by the Agency. The Agencies worked together to develop joint standards and, on June 10, 2015, they jointly published in the **Federal Register** [4] the ''Final Interagency Policy Statement Establishing Joint Standards for Assessing the Diversity Policies and Practices of Entities Regulated by the Agencies'' (Policy Statement).

[1] Steady state averages of 25 percent for Electronic Form (Implementation) and 75 percent for Electronic Form (Ongoing) submissions were estimated from historical submissions by FDIC-regulated IDIs covering diversity activities in 2019, the first reporting period for which the online submission was available, and multiplied by 175, the anticipated number of annual Electronic Form submissions, to arrive at estimates of 45 Electronic Form (Implementation) and 130 Electronic Form (Ongoing) submissions. For the purposes of annualizing the estimated number of respondents, it is assumed that the estimated annual count of respondents for Electronic Form (Ongoing) Submissions includes returning Electronic Form (Implementation) Submissions from the previous year.

[2] The FDIC found 0, 0, and 4 Free-Form submissions and 3, 3, and 12 Non-material submissions in 2017, 2018, and 2019, respectively. Based on these historical numbers and their supervisory experience, the FDIC anticipates approximately 5 Free-Form and 10 Non-material Submissions going forward.

[3] The average burden hour estimate across all submission types is 4 hours and 8 minutes per response.

[4] 80 FR 33016.

The Policy Statement contains a ''collection of information'' within the meaning of the Paperwork Reduction Act of 1995 (PRA). The Policy Statement includes Joint Standards that cover ''Practices to Promote Transparency of Organizational Diversity and Inclusion.'' These Joint Standards contemplate that a regulated entity is transparent about its diversity and inclusion activities by making certain information available to the public annually on its website or through other appropriate communications methods, in a manner reflective of the entity's size and other characteristics. The specific information referenced in these standards is: (a) Leadership commitment to diversity and inclusion; (b) workforce diversity and employment practices; (c) progress toward achieving diversity and inclusion in its procurement activities; and (d) opportunities available at the entity that promote diversity.

In addition, the Policy Statement includes Joint Standards that address ''Entities' Self-Assessment.'' The Joint Standards for Entities' Self-Assessment envision that a regulated entity, in a manner reflective of its size and other characteristics, (a) conducts annually a voluntary self-assessment of its diversity policies and practices; (b) monitors and evaluates its performance under its diversity policies and practices on an ongoing basis; (c) provides information pertaining to its self-assessment to the OMWI Director of its primary federal financial regulator; and (d) publishes information pertaining to its efforts with respect to the Joint Standards.

The collection of information described above is reported to the FDIC via the form entitled ''Diversity Self-Assessment of Financial Institutions Regulated by the FDIC,'' which can be submitted in paper [5] or electronic format.[6] To facilitate DSA submissions, the FDIC has developed the automated Financial Institution Diversity Self-Assessment (FID–SA) application. FID–SA provides FDIC-regulated financial institutions an easy and efficient way to electronically complete the diversity self-assessment; work with multiple users; view previous submissions; attach supporting material; and print and save in pdf format.[7]

Request for Comment

Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the FDIC's functions, including whether the information has practical utility; (b) the accuracy of the estimates of the burden of the information collection, including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology. All comments will become a matter of public record.

Federal Deposit Insurance Corporation.

Dated at Washington, DC, on November 9, 2021.

James P. Sheesley,

Assistant Executive Secretary.

[FR Doc. 2021–24814 Filed 11–12–21; 8:45 am]

BILLING CODE 6714–01–P

[5] The paper version of the ''Diversity Self-Assessment of Financial Institutions Regulated by the FDIC'' form (form number 2710/05) can be viewed at the following location: *https://www.fdic.gov/resources/regulations/federal-register-publications/2021/2021-form-2710-05-diversity-self-assessment-paper-form.pdf.*

[6] The electronic version of the ''Diversity Self-Assessment of Financial Institutions Regulated by the FDIC'' form (form number 2710/06) can be viewed at the following location: *https://www.fdic.gov/resources/regulations/federal-register-publications/2021/2021-form-2710-06-diversity-self-assessment-screen-shots.docx.*

[7] As described in the FID–SA portal, available at *https://www.fdic.gov/about/diversity/fidsaportal.html (accessed May 1, 2021).*

FEDERAL MARITIME COMMISSION

Notice of Agreements Filed

The Commission hereby gives notice of the filing of the following agreements under the Shipping Act of 1984. Interested parties may submit comments, relevant information, or documents regarding the agreements to the Secretary by email at *Secretary@fmc.gov,* or by mail, Federal Maritime Commission, Washington, DC 20573. Comments will be most helpful to the Commission if received within 12 days of the date this notice appears in the **Federal Register**. Copies of agreements are available through the Commission's website (*www.fmc.gov*) or by contacting the Office of Agreements at (202)-523–5793 or *tradeanalysis@fmc.gov.*

Agreement No.: 201143–020.

Agreement Name: West Coast MTO Agreement.

Parties: APM Terminals Pacific LLC; Fenix Marine Services, Ltd.; Everport Terminal Services, Inc.; International Transportation Service, LLC; LBCT LLC dba Long Beach Container Terminal LLC; Total Terminals International, LLC; West Basin Container Terminal LLC; Pacific Maritime Services, LLC; SSAT (Pier A), LLC; Trapac LLC; Yusen Terminals LLC; and SSA Terminals, LLC.

Filing Party: Wayne Rohde; Cozen O'Connor.

Synopsis: The amendment adds a new Article XII to the Agreement that temporarily suspends the flat fee currently provided for in the Agreement through January 31, 2022 and provides for the collection of a different Traffic Mitigation Fee only between the hours of 7:00 a.m. and 5:59 p.m. during that period. The parties have requested expedited review.

Proposed Effective Date: 12/23/2021

Location: https://www2.fmc.gov/FMC.Agreements.Web/Public/AgreementHistory/2090.

Editorial note: This document was received for publication by the Office of the Federal Register on November 8, 2021.

Dated: March 4, 2021.

Rachel E. Dickon,

Secretary.

[FR Doc. 2021–24758 Filed 11–12–21; 8:45 am]

BILLING CODE 6730–02–P

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The public portions of the applications listed below, as well as other related filings required by the Board, if any, are available for immediate inspection at the Federal Reserve Bank(s) indicated below and at the offices of the Board of Governors. This information may also be obtained on an expedited basis, upon request, by contacting the appropriate Federal Reserve Bank and from the Board's Freedom of Information Office at *https://www.federalreserve.gov/foia/request.htm.* Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)).

Comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors, Ann E. Misback, Secretary of the Board, 20th Street and Constitution Avenue NW, Washington, DC 20551–0001, not later than December 15, 2021.

A. Federal Reserve Bank of New York (Ivan Hurwitz, Senior Vice President) 33

Liberty Street, New York, New York 10045–0001. Comments can also be sent electronically to *Comments.applications@ny.frb.org:*

1. *Valley National Bancorp, New York, New York;* to acquire Bank Leumi Le-Israel Corporation, and thereby indirectly acquire Bank Leumi USA, both of New York, New York.

B. Federal Reserve Bank of Atlanta (Erien O. Terry, Assistant Vice President) 1000 Peachtree Street NE, Atlanta, Georgia 30309. Comments can also be sent electronically to *Applications.Comments@atl.frb.org:*

1. *Business First Bancshares, Inc., Baton Rouge, Louisiana;* to merge with Texas Citizens Bancorp, Inc., and thereby indirectly acquire Texas Citizens Bank, N.A., both of Pasadena, Texas.

C. Federal Reserve Bank of Minneapolis (Chris P. Wangen, Assistant Vice President), 90 Hennepin Avenue, Minneapolis, Minnesota 55480–0291. Comments can also be sent electronically to *MA@mpls.frb.org:*

1. *First Interstate BancSystem, Inc., Billings, Montana;* to merge with Great Western Bancorp, Inc., and thereby indirectly acquire Great Western Bank, both of Sioux Falls, South Dakota.

Board of Governors of the Federal Reserve System, November 9, 2021.

Michele Taylor Fennell,

Deputy Associate Secretary of the Board.

[FR Doc. 2021–24875 Filed 11–12–21; 8:45 am]

BILLING CODE P

FEDERAL RESERVE SYSTEM

Change in Bank Control Notices; Acquisitions of Shares of a Bank or Bank Holding Company

The notificants listed below have applied under the Change in Bank Control Act (Act) (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire shares of a bank or bank holding company. The factors that are considered in acting on the applications are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The public portions of the applications listed below, as well as other related filings required by the Board, if any, are available for immediate inspection at the Federal Reserve Bank(s) indicated below and at the offices of the Board of Governors. This information may also be obtained on an expedited basis, upon request, by contacting the appropriate Federal Reserve Bank and from the Board's Freedom of Information Office at *https://www.federalreserve.gov/foia/request.htm.* Interested persons may express their views in writing on the standards enumerated in paragraph 7 of the Act.

Comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors, Ann E. Misback, Secretary of the Board, 20th Street and Constitution Avenue NW, Washington, DC 20551–0001, not later than November 30, 2021.

A. Federal Reserve Bank of Minneapolis (Chris P. Wangen, Assistant Vice President), 90 Hennepin Avenue, Minneapolis, Minnesota 55480–0291. Comments can also be sent electronically to *MA@mpls.frb.org:*

1. *Bosshard Bank Irrevocable Trust u/a/d October 21, 2021, South Dakota Trust Company, LLC., as trustee, both of Sioux Falls, South Dakota; and Andrew R. Bosshard, as trust protector, La Crosse, Wisconsin;* to join the Bosshard Family Group, a group acting in concert, to acquire voting shares of Bosshard Banco, Ltd., La Crosse, Wisconsin, and thereby indirectly acquire voting shares of Intercity State Bank, Schofield, Wisconsin, and The First National Bank of Bangor, Bangor, Wisconsin; and acquire voting shares of Clayton Bankshares, Inc., and thereby indirectly acquire voting shares of Citizens State Bank-La Crosse, both of La Crosse, Wisconsin.

Board of Governors of the Federal Reserve System, November 9, 2021.

Michele Taylor Fennell,

Deputy Associate Secretary of the Board.

[FR Doc. 2021–24876 Filed 11–12–21; 8:45 am]

BILLING CODE P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel; Centers for Research on Structural Biology of Infectious Diseases (N01).

Date: December 14, 2021.

Time: 10:30 a.m. to 5:00 p.m.

Agenda: To review and evaluate contract proposals.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3F30A, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Ellen S. Buczko, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3F30A, Rockville, MD 20852, (240) 669–5028, *ebuczko1@niaid.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: November 8, 2021.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24771 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Environmental Health Sciences; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of a meeting of the Board of Scientific Counselors, NIEHS.

The meeting will be open to the public as indicated below, with attendance limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting.

The meeting will be closed to the public as indicated below in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended for the review, discussion, and evaluation of individual intramural programs and projects conducted by the National Institute of Environmental Health Sciences, including consideration of personnel qualifications and performance, and the competence of individual investigators, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Board of Scientific Counselors, NIEHS.

Date: December 5–7, 2021.

Closed: December 5, 2021, 4:00 p.m. to 5:00 p.m.

Agenda: Discussion of BSC Reviews.

Place: National Institute of Environmental Health Science, 111 T.W. Alexander Drive, Research Triangle Park, NC 27709 (Virtual Meeting).

Open: December 6, 2021, 9:30 a.m. to 11:50 a.m.

Agenda: Meeting Overview and Q & A Session.

Place: National Institute of Environmental Health Science, 111 T.W. Alexander Drive, Research Triangle Park, NC 27709 (Virtual Meeting).

Closed: December 6, 2021, 11:55 a.m. to 1:45 p.m.

Agenda: Sessions with Investigators.

Place: National Institute of Environmental Health Science, 111 T.W. Alexander Drive, Research Triangle Park, NC 27709 (Virtual Meeting).

Open: December 6, 2021, 1:50 p.m. to 3:20 p.m.

Agenda: Poster Session.

Place: National Institute of Environmental Health Science, 111 T.W. Alexander Drive, Research Triangle Park, NC 27709 (Virtual Meeting).

Closed: December 6, 2021, 3:35 p.m. to 5:00 p.m.

Agenda: Sessions with Trainees and Staff Scientist.

Place: National Institute of Environmental Health Science, 111 T.W. Alexander Drive, Research Triangle Park, NC 27709 (Virtual Meeting).

Open: December 7, 2021, 10:00 a.m. to 11:50 a.m.

Agenda: Q & A Session.

Place: National Institute of Environmental Health Science, 111 T.W. Alexander Drive, Research Triangle Park, NC 27709 (Virtual Meeting).

Closed: December 7, 2021, 11:55 a.m. to 5:00 p.m.

Agenda: Sessions with Investigators.

Place: National Institute of Environmental Health Science, 111 T.W. Alexander Drive, Research Triangle Park, NC 27709 (Virtual Meeting).

Contact Person: Darryl C. Zeldin, Scientific Director & Principal Investigator, Division of Intramural Research, National Institute of Environmental Sciences, NIH, 111 T.W. Alexander Drive, Mail drop MSC A2–09, Research Triangle Park, NC 27709, 919–541–1169, *zeldin@niehs.nih.gov*.

Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

(Catalogue of Federal Domestic Assistance Program Nos. 93.115, Biometry and Risk Estimation—Health Risks from Environmental Exposures; 93.142, NIEHS Hazardous Waste Worker Health and Safety Training; 93.143, NIEHS Superfund Hazardous Substances—Basic Research and Education; 93.894, Resources and Manpower Development in the Environmental Health Sciences; 93.113, Biological Response to Environmental Health Hazards; 93.114, Applied Toxicological Research and Testing, National Institutes of Health, HHS)

Dated: November 8, 2021.

David W. Freeman,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24773 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel; Adjuvant Comparison and Characterization (N01).

Date: December 7–8, 2021.

Time: 10:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate contract proposals.

Place: National Institute of Allergy and Infectious Disease, National Institutes of Health, 5601 Fishers Lane, Room 3G41, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Tara Capece, Ph.D., MPH, Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G41, Rockville, MD 20852, 240–191–4281, *capecet2@niaid.nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: November 8, 2021.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24765 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis, Panel Developmental Centers for AIDS Research (P30 Clinical Trial Not Allowed).

Date: December 7–8, 2021.

Time: 11:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G21A, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Dimitrios N. Vatakis, Ph.D. Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G21A, Rockville, MD 20852 301–761–7176, *dimitrios.vatakis@nih.gov*.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis, Panel Centers for AIDS Research (P30 Clinical Trial Not Allowed).

Date: December 7–8, 2021.

Time: 11:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G21A, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Dimitrios N. Vatakis, Ph.D. Scientific Review Officer, Scientific Review Program Division, of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G21A, Rockville, MD 20852 301–761–7176, *dimitrios.vatakis@nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: November 8, 2021.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24775 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel; NIH Support for Conferences and Scientific Meetings (Parent R13 Clinical Trial Not Allowed).

Date: December 8–10, 2021.

Time: 9:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G53, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Konrad Krzewski, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G53, Rockville, MD 20852, 240–747–7526, *konrad.krzewski@nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: November 8, 2021.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24778 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Mental Health; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Mental Health Special Emphasis Panel; Services Member Conflicts.

Date: December 8, 2021.

Time: 1:00 p.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852, (Telephone Conference Call).

Contact Person: Jasenka Borzan, Ph.D., Scientific Review Officer, Division of Extramural Activities, National Institutes of Mental Health, 6001 Executive Blvd. Neuroscience Center, Room 6150, Bethesda, MD 20892, 301–435–1260, *jasenka.borzan@nih.gov.*

Name of Committee: National Institute of Mental Health Special Emphasis Panel; RFA Review: Adapting Immunotherapy and Gene Editing Based Strategies for Targeting HIV Reservoirs in the CNS.

Date: December 9, 2021.

Time: 10:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852 (Telephone Conference Call).

Contact Person: Nicholas Gaiano, Ph.D., Review Branch Chief, Division of Extramural Activities, National Institute of Mental Health, NIH, Neuroscience Center/Room 6150/MSC 9606, 6001 Executive Boulevard, Bethesda, MD 20892–9606, 301–443–2742, *nick.gaiano@nih.gov.*

(Catalogue of Federal Domestic Assistance Program No. 93.242, Mental Health Research Grants, National Institutes of Health, HHS)

Dated: November 9, 2021.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24827 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Center for Scientific Review Special Emphasis Panel; Vascular and Hematology.

Date: December 3, 2021.

Time: 9:00 a.m. to 11:00 a.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Ashlee Lane, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20817, 301–451–3849, *ashlee.tipton@nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Drug Discovery, Medicinal Chemistry and Membrane Proteins.

Date: December 10, 2021.

Time: 11:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Joanne T Fujii, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4184, MSC 7850, Bethesda, MD 20892, (301) 435–1178, *fujiij@csr.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine; 93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS)

Dated: November 9, 2021.

Miguelina Perez,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24872 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel; Multidisciplinary Treatment Approaches to End the HIV Epidemic (R01 Clinical Trial Optional).

Date: December 6, 2021.

Time: 11:00 a.m. to 3:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G21, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Robert C. Unfer, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G21, Rockville, MD 20852, Rockville, MD 20892–9823, 240–669–5035, *unferrc@nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: November 8, 2021.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24774 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Aging; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute on Aging Special Emphasis Panel; Precursors of AD/ADHD.

Date: November 30, 2021.

Time: 1:30 p.m. to 3:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute on Aging, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20814 (Video Meeting).

Contact Person: Kimberly Firth, Ph.D., Scientific Review Officer, Scientific Review Branch, National Institute on Aging, National Institutes of Health, Gateway Building, 7201 Wisconsin Avenue, Suite 2W200, Bethesda, MD 20892, 301–402–7702, *firthkm@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.866, Aging Research, National Institutes of Health, HHS)

Dated: November 9, 2021.

Miguelina Perez,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24873 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel; Global Infectious Disease Research Administration Development Award for Low- and Middle-Income Country Institutions (G11 Clinical Trial Not Allowed).

Date: December 16, 2021.

Time: 10:00 a.m. to 1:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G13B, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Yong Gao, Ph.D. Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G13B, Rockville, MD 20852, (240) 669–5048, *yong.gao@nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: November 8, 2021.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24777 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel; DMID Clinical Materials Services (N01).

Date: December 14, 2021.

Time: 1:00 p.m. to 5:30 p.m.

Agenda: To review and evaluate contract proposals.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3E70A, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Annie Walker-Abbey, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural

Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3E70A, Rockville, MD 208523, 240–627–3390, *aabbey@niaid.nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: November 8, 2021.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24768 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Mental Health (NIMH); Notice of Meeting

Pursuant to section 10(a) of the Federal Advisory Committee Act, as amended, notice is hereby given of a meeting of the Interagency Autism Coordinating Committee.

The purpose of the IACC meeting is to discuss business, agency updates, and issues related to autism spectrum disorder (ASD) research and services activities. The meeting will be held as a virtual meeting and is open to the public. Individuals who plan to view the virtual meeting and need special assistance or other reasonable accommodations to view the meeting should notify the Contact Person listed below at least seven (7) business days in advance of the meeting. The open session will be videocast and can be accessed from the NIH Videocast website (*https://videocast.nih.gov/watch=44055*).

Name of Committee: Interagency Autism Coordinating Committee (IACC).

Date: January 19, 2022 Meeting schedule subject to change.

Time: 10:00 a.m. to 5:00 p.m.

Meeting Access: Wednesday, January 19, 2022 *https://videocast.nih.gov/watch=44055*.

Agenda: To discuss business, updates, and issues related to ASD research and services activities.

Cost: The meeting is free and open to the public.

Registration: A registration web link will be posted on the IACC website (*www.iacc.hhs.gov*) prior to the meeting. Pre-registration is recommended.

Deadlines: Written/Virtual Public Comment Due Date: Friday, January 7, 2022, by 5:00 p.m. ET, For instructions, see below.

Contact Person: Ms. Rebecca Martin, Office of Autism Research Coordination, National Institute of Mental Health, NIH, 6001 Executive Boulevard, Bethesda, MD 20892–9669, Phone: 301–435–0886, *Email: IACCPublicInquiries@mail.nih.gov*.

Public Comments

The IACC welcomes public comments from members of the autism community. As the IACC will be updating its Strategic Plan, comments related to issues that the community would like to see highlighted in the new IACC Strategic Plan are welcome. Comments may be submitted in writing via email to *IACCPublicInquiries@mail.nih.gov* or using the web form at: *https://iacc.hhs.gov/meetings/public-comments/submit/index.jsp* by 5:00 p.m. ET on Friday, January 7, 2022. A limited number of slots are available for individuals to provide a 2–3-minute summary or excerpt of their written comment to the IACC live during the virtual meeting using the virtual platform. For those interested in that opportunity, please indicate ''Interested in providing virtual comment'' in your written submission, along with your name, address, email, phone number, and professional/organizational affiliation so that the Office of Autism Research Coordination staff can contact you if a slot is available for you to provide a summary or excerpt of your comment via the virtual platform during the meeting. For any given meeting, priority for virtual comment slots will be given to commenters who have not previously provided virtual comments in the current calendar year. This will help ensure that as many individuals as possible have an opportunity to share comments. Commenters going over their allotted 3-minute slot may be asked to conclude immediately to allow other comments and the rest of the meeting to proceed on schedule.

Public comments received by 5:00 p.m. ET on Friday, January 7, 2022, will be provided to the IACC prior to the meeting for their consideration. Any written comments received after 5:00 p.m. ET, January 7, 2022, may be provided to the IACC either before or after the meeting, depending on the volume of comments received and the time required to process them in accordance with privacy regulations and other applicable Federal policies. The IACC is not able to individually respond to comments. All public comments become part of the public record. Attachments of copyrighted publications are not permitted, but web links or citations for any copyrighted works cited may be provided. For public comment guidelines, see: *https://iacc.hhs.gov/meetings/public-comments/guidelines/.*

Technical Issues

If you experience any technical problems with the webcast, please email *IACCPublicInquiries@mail.nih.gov*.

Disability Accommodations

All IACC Full Meetings provide Closed Captioning through the NIH videocast website. Individuals whose full participation in the meeting will require special accommodations (*e.g.,* sign language or interpreting services, etc.) must submit a request to the Contact Person listed on the notice at least seven (7) business days prior to the meeting. Such requests should include a detailed description of the accommodation needed and a way for the IACC to contact the requester if more information is needed to fill the request. Last-minute requests may be made, but may not be possible to accommodate.

Additional Information

Information about the IACC is available on the website: *http://www.iacc.hhs.gov.*

Dated: November 9, 2021.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24839 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel; Mechanisms of HIV Resistance to Broadly Neutralizing Antibodies (bNAbs) (U01 Clinical Trial Not Allowed).

Date: December 8, 2021.

Time: 10:00 a.m. to 4:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G34, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Vishakha Sharma, Ph.D. Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health 5601 Fishers Lane, Room 3G34 Rockville, MD 20852, 301–761–7036, *vishakha.sharma@nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: November 8, 2021.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24776 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Center for Scientific Review Special Emphasis Panel; Molecular and Cellular Aspects of Obesity and Metabolic Disease.

Date: December 2, 2021.

Time: 10:00 a.m. to 1:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Raul Rojas, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6185, Bethesda, MD 20892, (301) 451–6319, *rojasr@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine; 93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS)

Dated: November 9, 2021.

Miguelina Perez,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24871 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Diabetes and Digestive and Kidney Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Diabetes and Digestive and Kidney Diseases Special Emphasis Panel; RFA DK21–007: NIDDK Standardization of C-Peptide and Measurements Program Special Emphasis Panel.

Date: February 3, 2022.

Time: 11:00 a.m. to 1:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Two Democracy Plaza, 6707 Democracy Boulevard, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Najma Begum, Ph.D., Scientific Review Officer, Review Branch, DEA, NIDDK, National Institutes of Health, 6707 Democracy Boulevard, Room 7349, Bethesda, MD 20892–5452, (301) 594–8894, *begumn@niddk.nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.847, Diabetes, Endocrinology and Metabolic Research; 93.848, Digestive Diseases and Nutrition Research; 93.849, Kidney Diseases, Urology and Hematology Research, National Institutes of Health, HHS)

Dated: November 9, 2021.

Miguelina Perez,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24870 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel; Understanding HIV Reservoir Dynamics (P01 Clinical Trial Not Allowed).

Date: December 9–10, 2021.

Time: 10:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G33B, Rockville, MD 20892 (Virtual Meeting).

Contact Person: John C. Pugh, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3G33B, Rockville, MD 20892, (301) 435–2398, *pughjohn@csr.nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: November 8, 2021.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2021–24779 Filed 11–12–21; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Substance Abuse and Mental Health Services Administration

Notice of Meeting; Substance Abuse and Mental Health Services Administration's Center for Substance Abuse Prevention

Pursuant to Public Law 92–463, notice is hereby given that the Substance Abuse and Mental Health Services Administration's (SAMHSA) Center for Substance Abuse Prevention (CSAP) Drug Testing Advisory Board (DTAB) will convene via web conference on December 7, 2021, from 10:00 a.m. ET to 4:30 p.m. ET.

The board will meet in open-session on December 7, 2021, from 10:00 a.m. ET to 11:55 a.m. ET, to discuss the Mandatory Guidelines for Federal Workplace Drug Testing Programs with updates from the Department of Transportation, the Nuclear Regulatory Commission, and the Department of Defense. Other discussion topics include a presentation on tetrahydrocannabinol isomerism and an update on the federal electronic custody and control form (eCCF). The board will meet in closed-session on December 7, 2021, from 1:00 p.m. to 4:30 p.m. ET, to review and discuss revisions to the Urine, Oral Fluid and Hair Mandatory Guidelines for Federal Workplace Drug Testing Programs, hair specimen proficiency testing, and hydroxy cocaine and cocaine ratios that have not been made public by the Department of Health and Human Services. Therefore, the meeting on December 7, 2021, from 1:00 p.m. ET to 4:30 p.m. ET, will be closed to the public, as determined by the Assistant Secretary for Mental Health and Substance Use, SAMHSA, in accordance with 5 U.S.C. 552b(9)(B) and 5 U.S.C. App. 2, Section 10(d).

Meeting registration information can be completed at *http://snacregister.samhsa.gov/MeetingList.aspx.* Web conference and call information will be sent after completing registration. Meeting information and a roster of DTAB members may be obtained by accessing the SAMHSA Advisory Committees website, *https://www.samhsa.gov/about-us/advisory-councils/meetings* or by contacting the Acting Designated Federal Officer, Anastasia Donovan.

Committee Name: Substance Abuse and Mental Health Services Administration, Center for Substance Abuse Prevention, Drug Testing Advisory Board.

Dates/Time/Type: December 7, 2021, from 10:00 a.m. to 11:55 a.m. ET: OPEN, December 7, 2021, from 1:00 p.m. to 4:30 p.m. ET: CLOSED.

Place: Substance Abuse and Mental Health Services Administration, 5600 Fishers Lane, Rockville, MD 20857.

Contact: Anastasia Donovan, Policy Analyst, Center for Substance Abuse Prevention, 5600 Fishers Lane, Room 16N06B, Rockville, Maryland 20857, Telephone: (240) 276–1116, Email: *anastasia.donovan@samhsa.hhs.gov.*

Dated: November 8, 2021.

Carlos Castillo,

Committee Management Officer.

[FR Doc. 2021–24807 Filed 11–12–21; 8:45 am]

BILLING CODE 4162–20–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

[1651–0019]

Vessel Entrance or Clearance Statement

AGENCY: U.S. Customs and Border Protection (CBP), Department of Homeland Security.

ACTION: 60-Day Notice and request for comments; revision of an existing collection of information.

SUMMARY: The Department of Homeland Security, U.S. Customs and Border Protection will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (PRA). The information collection is published in the **Federal Register** to obtain comments from the public and affected agencies.

DATES: Comments are encouraged and must be submitted (no later than January 14, 2022) to be assured of consideration.

ADDRESSES: Written comments and/or suggestions regarding the item(s) contained in this notice must include the OMB Control Number 1651–0019 in the subject line and the agency name. Please use the following method to submit comments:

Email. Submit comments to: *CBP_PRA@cbp.dhs.gov.*

Due to COVID–19-related restrictions, CBP has temporarily suspended its ability to receive public comments by mail.

FOR FURTHER INFORMATION CONTACT: Requests for additional PRA information should be directed to Seth Renkema, Chief, Economic Impact Analysis Branch, U.S. Customs and Border Protection, Office of Trade, Regulations and Rulings, 90 K Street NE, 10th Floor, Washington, DC 20229–1177, telephone number 202–325–0056, or via email *CBP_PRA@cbp.dhs.gov.* Please note that the contact information provided here is solely for questions regarding this notice. Individuals seeking information about other CBP programs should contact the CBP National Customer Service Center at 877–227–5511, (TTY) 1–800–877–8339, or CBP website at *https://www.cbp.gov/.*

SUPPLEMENTARY INFORMATION: CBP invites the general public and other Federal agencies to comment on the proposed and/or continuing information collections pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). This process is conducted in accordance with 5 CFR 1320.8. Written comments and suggestions from the public and affected agencies should address one or more of the following four points: (1) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (3) suggestions to enhance the quality, utility, and clarity of the information to be collected; and (4) suggestions to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses. The comments that are submitted will be summarized and included in the request for approval. All comments will become a matter of public record.

Overview of This Information Collection

Title: Vessel Entrance or Clearance Statement.

OMB Number: 1651–0019.

Form Number: CBP Form 1300.

Current Actions: Revision of an existing collection of information.

Type of Review: Revision.

Affected Public: Businesses.

Abstract: CBP Form 1300, Vessel Entrance or Clearance Statement, was developed through agreement by the United Nations Intergovernmental Maritime Organization (IMO) in conjunction with the United States and various other countries. The form was

developed as a single form to replace the numerous other forms used by various countries for the entrance and clearance of vessels. CBP Form 1300 is authorized by 19 U.S.C. 1431, 1433, and 1434, and provided for by 19 CFR 4. This form is accessible at *http://www.cbp.gov/newsroom/publications/forms?title=1300&=Apply.*

This form is, currently, physically submitted and is anticipated to be electronically submitted as part of CBP's efforts to automate maritime forms through the Vessel Entrance and Clearance System (VECS), which will reduce the need for paper submission of any vessel entrance or clearance requirements under the above referenced statutes and regulations. VECS will still collect and maintain the same data as CBP Form 1300, but will automate the capture of data to reduce or eliminate redundancy with other data collected by CBP.

Proposed Changes

1. New ACE Account Type

CBP is adding a new ACE Account type for Vessel Agencies: Vessel Agency Account. The new account type within ACE will operate as a portal to the Vessel Entrance and Clearance System (VECS), which will run as its own separate system.

Vessel Agents will be required to provide identifying information such as, their name, their employer identification number (EIN), company address, and their phone numbers, which will be requested at the time Vessel Agents apply for the new ACE account type.

After creating an ACE account, Vessel Agencies, Vessel Operating Common Carriers (VOCCs), and their designees maybe able to use the new Vessel Entrance and Clearance System (VECS) as part of a forthcoming pilot program to test the functionality of VECS, and will be able to file vessel entrance, clearance, and related data to CBP electronically.

2. VECS Public Pilot

VECS will automate and digitize the collection and processing of the data and filing requirements for which the CBP Form 1300 is used. CBP plans to run an initial public pilot to test the system. All users who obtained a Vessel Agency Account through the ACE Portal will be automatically enrolled into the VECS public pilot. Initially, the pilot will begin at one of several ports where VECS is being internally tested. CBP will provide training to each CBP port and the Vessel Agency personnel at each port, prior to beginning/expanding the public pilot in another port.

The VECS public pilot will expand to other internal CBP testing ports based on knowledge and familiarity with the system. The VECS public pilot will then, based on pilot results, expand to additional ports, in an effort to progressively test and implement the system nationwide. There will be no change to CBP Form 1300 and CBP Form 1300 will continue to be accepted.

Type of Information Collection: Vessel Entrance or Clearance Statement (CBP Form 1300).

Estimated Number of Respondents: 2,624.

Estimated Number of Annual Responses per Respondent: 72.

Estimated Number of Total Annual Responses: 188,928.

Estimated Time per Response: 30 minutes (0.5 hours).

Estimated Total Annual Burden Hours: 94,464.

Dated: November 9, 2021.

Seth D. Renkema,

Branch Chief, Economic Impact Analysis Branch, U.S. Customs and Border Protection.

[FR Doc. 2021–24838 Filed 11–12–21; 8:45 am]

BILLING CODE P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

[1651–0105]

Application to Use Automated Commercial Environment (ACE)

AGENCY: U.S. Customs and Border Protection (CBP), Department of Homeland Security.

ACTION: 60-Day Notice and request for comments; revision of an existing collection of information.

SUMMARY: The Department of Homeland Security, U.S. Customs and Border Protection will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (PRA). The information collection is published in the **Federal Register** to obtain comments from the public and affected agencies.

DATES: Comments are encouraged and must be submitted (no later than January 14, 2022) to be assured of consideration.

ADDRESSES: Written comments and/or suggestions regarding the item(s) contained in this notice must include the OMB Control Number 1651–0105 in the subject line and the agency name. Please use the following method to submit comments:

Email. *Submit comments to: CBP_PRA@cbp.dhs.gov.*

Due to COVID–19-related restrictions, CBP has temporarily suspended its ability to receive public comments by mail.

FOR FURTHER INFORMATION CONTACT: Requests for additional PRA information should be directed to Seth Renkema, Chief, Economic Impact Analysis Branch, U.S. Customs and Border Protection, Office of Trade, Regulations and Rulings, 90 K Street NE, 10th Floor, Washington, DC 20229–1177, telephone number 202–325–0056 or via email *CBP_PRA@cbp.dhs.gov.* Please note that the contact information provided here is solely for questions regarding this notice. Individuals seeking information about other CBP programs should contact the CBP National Customer Service Center at 877–227–5511, (TTY) 1–800–877–8339, or CBP website at *https://www.cbp.gov/.*

SUPPLEMENTARY INFORMATION: CBP invites the general public and other Federal agencies to comment on the proposed and/or continuing information collections pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). This process is conducted in accordance with 5 CFR 1320.8. Written comments and suggestions from the public and affected agencies should address one or more of the following four points: (1) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (3) suggestions to enhance the quality, utility, and clarity of the information to be collected; and (4) suggestions to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses. The comments that are submitted will be summarized and included in the request for approval. All comments will become a matter of public record.

Overview of This Information Collection

Title: Application to use Automated Commercial Environment.

OMB Number: 1651–0105.
Form Number: N/A.
Current Actions: Revision of an existing collection of information.
Type of Review: Revision.
Affected Public: Businesses.
Abstract: The Automated Commercial Environment (ACE) is a trade data processing system that is replacing the Automated Commercial System (ACS), the current import system for U.S. Customs and Border Protection (CBP) operations. ACE is authorized by Executive Order 13659 which mandates implementation of a Single Window through which businesses will transmit data required by participating agencies for the importation or exportation of cargo. *See* 79 FR 10655 (February 25, 2014). ACE supports government agencies and the trade community with border-related missions with respect to moving goods across the border efficiently and securely. Once ACE is fully implemented, all related CBP trade functions and the trade community will be supported from a single common user interface.

To establish an ACE Portal account, participants submit information such as their name, their employer identification number (EIN) or social security number (SSN), and if applicable, a statement certifying their capability to connect to the internet. This information is submitted through the ACE Secure Data Portal which is accessible at: *http://www.cbp.gov/trade/automated.*

Please Note: A CBP-assigned number may be provided in lieu of your SSN. If you have an EIN, that number will automatically be used and no CBP number will be assigned. A CBP-assigned number is for CBP use only.

There is a standalone capability for electronically filing protests in ACE. This capability is available for participants who have not established ACE Portal Accounts for other trade activities, but desire to file protests electronically. A protest is a procedure whereby a private party may administratively challenge a CBP decision regarding imported merchandise and certain other CBP decisions. Trade members can establish a protest filer account in ACE through a separate application and the submission of specific data elements. *See* 81 FR 57928 (August 24, 2016).

Proposed Changes

1. New ACE Account Type

CBP is creating a new ACE Account type for ACE Import Trade Carriers and their designees. This new account type: Vessel Agency, enables users the ability to file vessel entrance, clearance, and related data to CBP electronically through the new Vessel Entrance and Clearance System (VECS).

The ACE Account Application will be changed to collect identifying information such as their name, their employer identification number (EIN), their company address, and their phone numbers, to be used to setup their Vessel Agency accounts. Users who create a Vessel Agency Account are automatically enrolled into the VECS public pilot.

2. Removing ACE Account Types

In a separate action, unrelated to the Vessel Agency account type creation, CBP will also be removing account types ''Cartman'', ''Claimant'', and ''Lighterman'' from the ACE Account Application. These account types were never used and are being removed due to that lack of use.

Type of Information Collection: Application to ACE (Import).
Estimated Number of Respondents: 21,571.
Estimated Number of Annual Responses per Respondent: 1.
Estimated Number of Total Annual Responses: 21,571.
Estimated Time per Response: 20 minutes (0.33 hours).
Estimated Total Annual Burden Hours: 7,118.

Type of Information Collection: Application to ACE (Export).
Estimated Number of Respondents: 9,000.
Estimated Number of Annual Responses per Respondent: 1.
Estimated Number of Total Annual Responses: 9,000.
Estimated Time per Response: 4 minutes (0.066 hours).
Estimated Total Annual Burden Hours: 594.

Type of Information Collection: Application to Establish an ACE Protest Filer Account.
Estimated Number of Respondents: 3,750.
Estimated Number of Annual Responses per Respondent: 1.
Estimated Number of Total Annual Responses: 3,750.
Estimated Time per Response: 4 minutes (0.066 hours).
Estimated Total Annual Burden Hours: 248.

Dated: November 9, 2021.

Seth D. Renkema,

Branch Chief, Economic Impact Analysis Branch, U.S. Customs and Border Protection.

[FR Doc. 2021–24840 Filed 11–12–21; 8:45 am]

BILLING CODE P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4615–DR; Docket ID FEMA–2021–0001]

New York; Amendment No. 4 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of New York (FEMA–4615–DR), dated September 5, 2021, and related determinations.

DATES: This amendment was issued October 20, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street, SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of New York is hereby amended to include the following area among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of September 5, 2021.

Dutchess County for Individual Assistance (already designated for Public Assistance).

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24736 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4611–DR; Docket ID FEMA–2021–0001]

Louisiana; Amendment No. 4 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Louisiana (FEMA–4611–DR), dated August 29, 2021, and related determinations.

DATES: This amendment was issued October 19, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of Louisiana is hereby amended to include the following areas among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of August 29, 2021.

Plaquemines, St. Bernard, St. Tammany, Tangipahoa, and Washington Parishes for permanent work [Categories C–G] (already designated for Individual Assistance and assistance for debris removal and emergency protective measures [Categories A and B], including direct federal assistance, under the Public Assistance program).

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24733 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4611–DR; Docket ID FEMA–2021–0001]

Louisiana; Amendment No. 3 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster for the State of Louisiana (FEMA–4611–DR), dated August 29, 2021, and related determinations.

DATES: This amendment was issued September 24, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street, SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated September 24, 2021, the President amended the cost-sharing arrangements regarding Federal funds provided under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), in a letter to Deanne Criswell, Administrator, Federal Emergency Management Agency, Department of Homeland Security, under Executive Order 12148, as follows:

I have determined that the damage in certain areas of the State of Louisiana resulting from Hurricane Ida during the period of August 26 to September 3, 2021, is of sufficient severity and magnitude that special cost sharing arrangements are warranted regarding Federal funds provided under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act'').

Therefore, I amend my declaration of August 29, 2021, to authorize an extension of the period of 100 percent Federal funding for debris removal and emergency protective measures (Categories A and B), including direct Federal assistance, under the Public Assistance program from 30 to 45 continuous days from the start of the incident period.

In addition, I amend my declaration of August 29, 2021, to authorize Federal funds for all categories of Public Assistance at 90 percent of total eligible costs, except for assistance previously authorized at 100 percent.

This adjustment to State and local cost sharing applies only to Public Assistance costs and direct Federal assistance eligible for such adjustments under the law. The Stafford Act specifically prohibits a similar adjustment for funds provided for Other Needs Assistance (Section 408) and the Hazard Mitigation Grant Program (Section 404). These funds will continue to be reimbursed at 75 percent of total eligible costs.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24732 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2021–0001]

Notice of Adjustment of Countywide Per Capita Impact Indicator

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: FEMA gives notice that the countywide per capita impact indicator under the Public Assistance program for disasters declared on or after October 1, 2021, will be increased.

DATES: This adjustment applies to major disasters declared on or after October 1, 2021.

FOR FURTHER INFORMATION CONTACT: Tod Wells, Recovery Directorate, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–3834.

SUPPLEMENTARY INFORMATION: In assessing damages for area designations under 44 CFR 206.40(b), FEMA uses a countywide per capita indicator to evaluate the impact of the disaster at the county level. FEMA will adjust the countywide per capita impact indicator under the Public Assistance program to reflect annual changes in the Consumer Price Index for All Urban Consumers published by the Department of Labor.

FEMA gives notice of an increase in the countywide per capita impact

indicator to $4.10 for all disasters declared on or after October 1, 2021.

FEMA bases the adjustment on an increase in the Consumer Price Index for All Urban Consumers of 5.3 percent for the 12-month period that ended in August 2021. The Bureau of Labor Statistics of the U.S. Department of Labor released the information on September 14, 2021.

Catalog of Federal Domestic Assistance No. 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters)

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24752 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2021–0001]

Notice of Adjustment of Disaster Grant Amounts

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: FEMA gives notice of an adjustment to the threshold for Small Project subgrants made to state, tribal, and local governments and private nonprofit facilities for disasters declared on or after October 1, 2021.

DATES: This adjustment applies to major disasters and emergencies declared on or after October 1, 2021.

FOR FURTHER INFORMATION CONTACT: Tod Wells, Recovery Directorate, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–3834.

SUPPLEMENTARY INFORMATION: The Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207, as amended by the Sandy Recovery Improvement Act, Public Law 113–2, provides that FEMA will annually adjust the threshold for assistance provided under section 422, Simplified Procedures, relating to the Public Assistance program, to reflect changes in the Consumer Price Index for All Urban Consumers published by the Department of Labor.

FEMA gives notice that $139,800 is the threshold for any Small Project subgrant made to state, tribal, and local governments or to the owner or operator of an eligible private nonprofit facility under section 422 of the Stafford Act for all major disasters or emergencies declared on or after October 1, 2021.

FEMA bases the adjustment on an increase in the Consumer Price Index for All Urban Consumers of 5.3 percent for the 12-month period that ended in August 2021. This is based on information released by the Bureau of Labor Statistics at the U.S. Department of Labor on September 14, 2021.

Catalog of Federal Domestic Assistance No. 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters).

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24753 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4623–DR; Docket ID FEMA–2021–0001]

Montana; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of Montana (FEMA–4623–DR), dated September 30, 2021, and related determinations.

DATES: The declaration was issued September 30, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated September 30, 2021, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), as follows:

I have determined that the damage in certain areas of the State of Montana resulting from the Richard Spring Fire during the period of August 8 to August 20, 2021, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of Montana.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration for the approved assistance to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, Alana B. Kuhn, of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of Montana have been designated as adversely affected by this major disaster:

Rosebud County and the Northern Cheyenne Indian Reservation for Public Assistance.

All areas within the State of Montana are eligible for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24745 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2020–0016]

Meeting To Implement Pandemic Response Voluntary Agreement Under Section 708 of the Defense Production Act

AGENCY: Federal Emergency Management Agency, Department of Homeland Security.

ACTION: Announcement of meeting; request for comments.

SUMMARY: The Federal Emergency Management Agency (FEMA) will hold a meeting remotely via web conference to implement the Voluntary Agreement for the Manufacture and Distribution of Critical Healthcare Resources Necessary to Respond to a Pandemic. A portion of the meeting will be open to the public.

DATES: The meeting will take place on Thursday, December 16, 2021, from 2 to 4 p.m. Eastern Time (ET). The first portion of the meeting, from approximately 2 to 3 p.m. ET, will be open to the public.

Written comments for consideration at the meeting must be submitted and received by 12 p.m. ET on Wednesday, December 15, 2021. Follow-up comments must be received by 5 p.m. ET on Wednesday, December 23, 2021, to be considered.

ADDRESSES: The meeting will be held via web conference. Members of the public may view the public portion of the meeting online at: *https://fema.zoomgov.com/j/1616569597?pwd=TEMzUzljZGR0YlJNVkVHbW1UUEN2Zz09.*

Reasonable accommodations are available for people with disabilities. To request a reasonable accommodation, contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section below as soon as possible. Last minute requests will be accepted but may not be possible to fulfill.

To facilitate public participation, members of the public are invited to provide written comments on the issues to be considered at the meeting. The Meeting Objectives listed below outline these issues. Written comments must be identified by Docket ID FEMA–2020–0016, and submitted by one of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov.* Follow the instructions for submitting comments.
- *Email:* FEMA Office of Response and Recovery, Office of Business, Industry, Infrastructure Integration, *OB3I@fema.dhs.gov.*

Instructions: All submissions must include the docket ID FEMA–2020–0016. Comments received, including any personal information provided, may be posted without alteration at *https://www.regulations.gov.*

Docket: For access to the docket and to read comments received by FEMA, go to *https://www.regulations.gov* and search for Docket ID FEMA–2020–0016.

FOR FURTHER INFORMATION CONTACT: Robert Glenn, Office of Business, Industry, Infrastructure Integration, via email at *OB3I@fema.dhs.gov* or via phone at (202) 212–1666.

SUPPLEMENTARY INFORMATION: Notice of this meeting is provided as required by section 708(h)(8) of the Defense Production Act (DPA), 50 U.S.C. 4558(h)(8), and consistent with 44 CFR part 332.

The DPA authorizes the making of ''voluntary agreements and plans of action'' with representatives of industry, business, and other interests to help provide for the national defense.[1] The President's authority to facilitate voluntary agreements with respect to responding to the spread of COVID–19 within the United States was delegated to the Secretary of Homeland Security in Executive Order 13911.[2] The Secretary of Homeland Security further delegated this authority to the FEMA Administrator.[3]

On August 17, 2020, after the appropriate consultations with the Attorney General and the Chairman of the Federal Trade Commission, FEMA completed and published in the **Federal Register** a ''Voluntary Agreement, Manufacture and Distribution of Critical Healthcare Resources Necessary to Respond to a Pandemic'' (Voluntary Agreement).[4] Unless terminated earlier, the Voluntary Agreement is effective until August 17, 2025, and may be extended subject to additional approval by the Attorney General after consultation with the Chairman of the Federal Trade Commission. The Agreement may be used to prepare for or respond to any pandemic, including COVID–19, during that time.

On December 7, 2020, the first plan of action under the Voluntary Agreement—the Plan of Action to Establish a National Strategy for the Manufacture, Allocation, and Distribution of Personal Protective Equipment (PPE) to Respond to COVID–19 (PPE Plan of Action)—was finalized.[5] The PPE Plan of Action established several sub-committees under the Voluntary Agreement, focusing on different aspects of the PPE Plan of Action.

On May 24, 2021, four additional plans of action under the Voluntary Agreement—the Plan of Action to Establish a National Strategy for the Manufacture, Allocation, and Distribution of Diagnostic Test Kits and other Testing Components to respond to COVID–19, the Plan of Action to Establish a National Strategy for the Manufacture, Allocation, and Distribution of Drug Products, Drug Substances, and Associated Medical Devices to respond to COVID–19, the Plan of Action to Establish a National Strategy for the Manufacture, Allocation, and Distribution of Medical Devices to respond to COVID–19, and the Plan of Action to Establish a National Strategy for the Manufacture, Allocation, and Distribution of Medical Gases to respond to COVID–19—were finalized.[6] These plans of action established several sub-committees under the Voluntary Agreement, focusing on different aspects of each plan of action.

On October 15, 2021, the sixth plan of action under the Voluntary Agreement—the Plan of Action to Establish a National Strategy for the Coordination of National Multimodal Healthcare Supply Chains to Respond to COVID–19—was finalized.[7] This plan of action established several sub-committees under the Voluntary Agreement, focusing on different transportation categories.

The meeting is chaired by the FEMA Administrator's delegates from the Office of Response and Recovery (ORR) and Office of Policy and Program Analysis (OPPA), attended by the Attorney General's delegates from the U.S. Department of Justice, and attended by the Chairman of the Federal Trade Commission's delegates. In implementing the Voluntary Agreement, FEMA adheres to all procedural

[1] 50 U.S.C. 4558(c)(1).

[2] 85 FR 18403 (Apr. 1, 2020).

[3] DHS Delegation 09052, Rev. 00.1 (Apr. 1, 2020); DHS Delegation Number 09052 Rev. 00 (Jan. 3, 2017).

[4] 85 FR 50035 (Aug. 17, 2020). The Attorney General, in consultation with the Chairman of the Federal Trade Commission, made the required finding that the purpose of the voluntary agreement may not reasonably be achieved through an agreement having less anticompetitive effects or without any voluntary agreement and published the finding in the **Federal Register** on the same day. 85 FR 50049 (Aug. 17, 2020).

[5] *See* 85 FR 78869 (Dec. 7, 2020). *See also* 85 FR 79020 (Dec. 8, 2020).

[6] *See* 86 FR 27894 (May 24, 2021). *See also* 86 FR 28851 (May 28, 2021).

[7] *See* 86 FR 57444 (October 15, 2021).

requirements of 50 U.S.C. 4558 and 44 CFR part 332.

Meeting Objectives: The objective of the meeting is to update the general public, and private industry partners, on the status of the Voluntary Agreement, the recently established National Multimodal Plan of Action, and other Plans of Action concerning PPE, Medical Devices, Medical Gases, Diagnostic Testing Kits, and Drug Products/Drug Substances.

Meeting Closed to the Public: By default, the DPA requires meetings held to implement a voluntary agreement or plan of action be open to the public.[8] However, attendance may be limited if the Sponsor[9] of the Voluntary Agreement finds that the matter to be discussed at a meeting falls within the purview of matters described in 5 U.S.C. 552b(c). The Sponsor of the Voluntary Agreement, the FEMA Administrator, found that a portion of this meeting to implement the Voluntary Agreement involves matters which fall within the purview of matters described in 5 U.S.C. 552b(c) and that portion of the meeting will therefore be closed to the public.

Specifically, the meeting to implement the Voluntary Agreement may require participants to disclose trade secrets or commercial or financial information that is privileged or confidential. Disclosure of such information allows for meetings to be closed pursuant to 5 U.S.C. 552b(c)(4). In addition, the success of the Voluntary Agreement depends wholly on the willing and enthusiastic participation of private sector participants. Failure to close the meeting to the public could have a strong chilling effect on participation by the private sector and cause a substantial risk of premature public release of sensitive information. Such a release of sensitive information could result in participants withdrawing their support from the Voluntary Agreement and thus significantly frustrating the implementation of the Voluntary Agreement. Frustration of an agency's objective due to premature disclosure of information allows for the closure of a meeting pursuant to 5 U.S.C. 552b(c)(9)(B).

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24886 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–19–P

[8] *See* 50 U.S.C. 4558(h)(7).

[9] ''[T]he individual designated by the President in subsection (c)(2) [of section 708 of the DPA] to administer the voluntary agreement, or plan of action.'' 50 U.S.C. 4558(h)(7).

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4628–DR; Docket ID FEMA–2021–0001]

Virginia; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the Commonwealth of Virginia (FEMA–4628–DR), dated October 26, 2021, and related determinations.

DATES: The declaration was issued October 26, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated October 26, 2021, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), as follows:

I have determined that the damage in certain areas of the Commonwealth of Virginia resulting from flooding, landslides, and mudslides during the period of August 30 to August 31, 2021, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the Commonwealth of Virginia.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated area and Hazard Mitigation throughout the Commonwealth. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration for the approved assistance to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, Timothy S. Pheil, of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the Commonwealth of Virginia have been designated as adversely affected by this major disaster:

Buchanan County for Public Assistance.

All areas within the Commonwealth of Virginia are eligible for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24750 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4617–DR; Docket ID FEMA–2021–0001]

North Carolina; Amendment No. 1 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of North Carolina (FEMA–4617–DR), dated September 8, 2021, and related determinations.

DATES: This amendment was issued October 1, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of North Carolina is hereby amended to include the following areas among those areas determined to have

been adversely affected by the event declared a major disaster by the President in his declaration of September 8, 2021.

Ashe, Graham, Jackson, and Mitchell Counties for Public Assistance.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24737 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4614–DR; Docket ID FEMA–2021–0001]

New Jersey; Amendment No. 5 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of New Jersey (FEMA–4614–DR), dated September 5, 2021, and related determinations.

DATES: This amendment was issued October 13, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of New Jersey is hereby amended to include the following area among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of September 5, 2021.

Warren County for all categories of Public Assistance (already designated for Individual Assistance and emergency protective measures [Category B], limited to direct Federal assistance and reimbursement for mass care including evacuation and shelter support under the Public Assistance program).

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24735 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4622–DR; Docket ID FEMA–2021–0001]

New Hampshire; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of New Hampshire (FEMA–4622–DR), dated September 30, 2021, and related determinations.

DATES: The declaration was issued September 30, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated September 30, 2021, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), as follows:

I have determined that the damage in certain areas of the State of New Hampshire resulting from a severe storm and flooding during the period of July 17 to July 19, 2021, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of New Hampshire.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration for the approved assistance to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, Robert V. Fogel, of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of New Hampshire have been designated as adversely affected by this major disaster:

Cheshire County for Public Assistance.

All areas within the State of New Hampshire are eligible for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24743 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4618–DR; Docket ID FEMA–2021–0001]

Pennsylvania; Amendment No. 4 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the Commonwealth of Pennsylvania (FEMA–4618–DR), dated September 10, 2021, and related determinations.

DATES: This amendment was issued October 20, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the Commonwealth of Pennsylvania is hereby amended to include the following areas among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of September 10, 2021.

Delaware County for Public Assistance (already designated for Individual Assistance).

Dauphin County for Public Assistance.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters);

97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24740 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4622–DR; Docket ID FEMA–2021–0001]

New Hampshire; Amendment No. 1 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of New Hampshire (FEMA–4622–DR), dated September 30, 2021, and related determinations.

DATES: This change occurred on October 4, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, William Roy, of FEMA is appointed to act as the Federal Coordinating Officer for this disaster.

This action terminates the appointment of Robert V. Fogel as Federal Coordinating Officer for this disaster.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24744 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4627–DR; Docket ID FEMA–2021–0001]

Delaware; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of Delaware (FEMA–4627–DR), dated October 24, 2021, and related determinations.

DATES: The declaration was issued October 24, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated October 24, 2021, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), as follows:

I have determined that the damage in certain areas of the State of Delaware resulting from the remnants of Hurricane Ida during the period of September 1 to September 7, 2021, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of Delaware.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration for the approved assistance to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, Mark Kenneth O'Hanlon, of FEMA is appointed to act

as the Federal Coordinating Officer for this major disaster.

The following areas of the State of Delaware have been designated as adversely affected by this major disaster:

New Castle County for Public Assistance.

All areas within the State of Delaware are eligible for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24749 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4624–DR; Docket ID FEMA–2021–0001]

New Hampshire; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of New Hampshire (FEMA–4624–DR), dated October 4, 2021, and related determinations.

DATES: The declaration was issued October 4, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated October 4, 2021, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), as follows:

I have determined that the damage in certain areas of the State of New Hampshire resulting from a severe storm and flooding during the period of July 29 to July 30, 2021, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of New Hampshire.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration for the approved assistance to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, William Roy, of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of New Hampshire have been designated as adversely affected by this major disaster:

Cheshire and Sullivan Counties for Public Assistance.

All areas within the State of New Hampshire are eligible for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24746 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4625–DR; Docket ID FEMA–2021–0001]

New York; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of New York (FEMA–4625–DR), dated October 8, 2021, and related determinations.

DATES: The declaration was issued October 8, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated October 8, 2021, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), as follows:

I have determined that the damage in certain areas of the State of New York resulting from the remnants of Tropical Storm Fred during the period of August 18 to August 19, 2021, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of New York.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration for the approved assistance to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, Lai Sun Yee, of FEMA is appointed to act as the Federal

Coordinating Officer for this major disaster.

The following areas of the State of New York have been designated as adversely affected by this major disaster:

Allegany, Cayuga, Cortland, Lewis, Oneida, Steuben, Tioga, and Yates Counties for Public Assistance.

All areas within the State of New York are eligible for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24747 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4457–DR; Docket ID FEMA–2021–0001]

New Hampshire; Amendment No. 1 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of New Hampshire (FEMA–4457–DR), dated August 15, 2019, and related determinations.

DATES: This change occurred on October 4, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, William Roy, of FEMA is appointed to act as the Federal Coordinating Officer for this disaster.

This action terminates the appointment of James McPherson as Federal Coordinating Officer for this disaster.

The following Catalog of Federal Domestic Assistance

Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24729 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2021–0001]

Notice of Maximum Amount of Assistance Under the Individuals and Households Program

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: FEMA gives notice of the maximum amount for assistance under the Individuals and Households Program for emergencies and major disasters declared on or after October 1, 2021.

DATES: This adjustment applies to emergencies and major disasters declared on or after October 1, 2021.

FOR FURTHER INFORMATION CONTACT: Christopher B. Smith, Recovery Directorate, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 212–1000.

SUPPLEMENTARY INFORMATION: Section 408 of the Robert T. Stafford Disaster Relief and Emergency Assistance Act (the Stafford Act), 42 U.S.C. 5174, prescribes that FEMA must annually adjust the maximum amount for assistance provided under the Individuals and Households Program (IHP). FEMA gives notice that the maximum amount of IHP financial assistance provided to an individual or household under section 408 of the Stafford Act with respect to any single emergency or major disaster is $37,900 for housing assistance and $37,900 for other needs assistance. The increase in award amount is for any single emergency or major disaster declared on or after October 1, 2021. In addition, in accordance with 44 CFR 61.17(c), this increases the maximum amount of available coverage under any Group Flood Insurance Policy (GFIP) issued.

FEMA bases the adjustment on an increase in the Consumer Price Index for All Urban Consumers of 5.3 percent for the 12-month period, which ended in August 2021. The Bureau of Labor Statistics of the U.S. Department of Labor released the information on September 14, 2021.

Catalog of Federal Domestic Assistance No. 97.048, Federal Disaster Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24755 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4621–DR; Docket ID FEMA–2021–0001]

Vermont; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of Vermont (FEMA–4621–DR), dated September 29, 2021, and related determinations.

DATES: The declaration was issued September 29, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated

September 29, 2021, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), as follows:

I have determined that the damage in certain areas of the State of Vermont resulting from a severe storm and flooding during the period of July 29 to July 30, 2021, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of Vermont.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Public Assistance and Hazard Mitigation will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration for the approved assistance to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, James McPherson, of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of Vermont have been designated as adversely affected by this major disaster:

Bennington and Windham Counties for Public Assistance.

All areas within the State of Vermont are eligible for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24742 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4559–DR; Docket ID FEMA–2021–0001]

Louisiana; Amendment No. 17 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster for the State of Louisiana (FEMA–4559–DR), dated August 28, 2020, and related determinations.

DATES: This amendment was issued September 24, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated September 24, 2021, the President amended the cost-sharing arrangements regarding Federal funds provided under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), in a letter to Deanne Criswell, Administrator, Federal Emergency Management Agency, Department of Homeland Security, under Executive Order 12148, as follows:

I have determined that the damage in certain areas of the State of Louisiana resulting from Hurricane Laura during the period of August 22 to August 27, 2020, is of sufficient severity and magnitude that special cost sharing arrangements are warranted regarding Federal funds provided under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act'').

Therefore, I amend the declarations of August 28, 2020, October 29, 2020, and February 22, 2021, to authorize an extension of the period 100 percent Federal funding for debris removal and emergency protective measures (Categories A and B), including direct Federal assistance, under the Public Assistance program from 30 days to 45 continuous days established by the State of Louisiana.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24730 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4614–DR; Docket ID FEMA–2021–0001]

New Jersey; Amendment No. 4 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of New Jersey (FEMA–4614–DR), dated September 5, 2021, and related determinations.

DATES: This amendment was issued October 7, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of New Jersey is hereby amended to include the following areas among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of September 5, 2021.

Cape May County for Public Assistance.

Atlantic, Burlington, Camden, Cumberland, Monmouth, Ocean, Salem, Sussex and Warren Counties for emergency protective measures (Category B), limited to direct Federal assistance and reimbursement for mass care including evacuation and shelter support.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used

for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24734 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4626–DR; Docket ID FEMA–2021–0001]

Mississippi; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of Mississippi (FEMA–4626–DR), dated October 22, 2021, and related determinations.

DATES: The declaration was issued October 22, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated October 22, 2021, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), as follows:

I have determined that the damage in certain areas of the State of Mississippi resulting from Hurricane Ida during the period of August 28 to September 1, 2021, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of Mississippi.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Individual Assistance and Public Assistance in the designated areas and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Public Assistance, Hazard Mitigation, and Other Needs Assistance under section 408 will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration for the approved assistance to the extent allowable under the Stafford Act.

The time period prescribed for the implementation of section 310(a), Priority to Certain Applications for Public Facility and Public Housing Assistance, 42 U.S.C. 5153, shall be for a period not to exceed six months after the date of this declaration.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, Brett H. Howard, of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of Mississippi have been designated as adversely affected by this major disaster:

Amite, Hancock, Harrison, Jackson, Pearl River, Pike, Walthall, and Wilkinson Counties for Individual Assistance.

Amite, Claiborne, Copiah, Covington, Franklin, George, Hancock, Harrison, Jackson, Jefferson, Jefferson Davis, Lawrence, Lincoln, Pearl River, Pike, Simpson, Walthall, Wayne, and Wilkinson Counties for Public Assistance.

All areas within the State of Mississippi are eligible for assistance under the Hazard Mitigation Grant Program.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24748 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID FEMA–2021–0001]

Notice of Adjustment of Statewide Per Capita Impact Indicator

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: FEMA gives notice that the statewide per capita impact indicator under the Public Assistance program for disasters declared on or after October 1, 2021, will be increased.

DATES: This adjustment applies to major disasters declared on or after October 1, 2021.

FOR FURTHER INFORMATION CONTACT: Tod Wells, Recovery Directorate, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–3834.

SUPPLEMENTARY INFORMATION: 44 CFR 206.48 provides that FEMA will adjust the statewide per capita impact indicator under the Public Assistance program to reflect changes in the Consumer Price Index for All Urban Consumers published by the Department of Labor.

FEMA gives notice that the statewide per capita impact indicator will be increased to $1.63 for all disasters declared on or after October 1, 2021.

FEMA bases the adjustment on an increase in the Consumer Price Index for All Urban Consumers of 5.3 percent for the 12-month period that ended in August 2021. The Bureau of Labor Statistics of the U.S. Department of Labor released the information on September 14, 2021.

Catalog of Federal Domestic Assistance No. 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters).

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24751 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4410–DR; Docket ID FEMA–2021–0001]

Connecticut; Amendment No. 2 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Connecticut (FEMA–4410–DR), dated December 5, 2018, and related determinations.

DATES: This change occurred on October 4, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street, SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, Robert V. Fogel, of FEMA is appointed to act as the Federal Coordinating Officer for this disaster.

This action terminates the appointment of James McPherson as Federal Coordinating Officer for this disaster.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24728 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4618–DR; Docket ID FEMA–2021–0001]

Pennsylvania; Amendment No. 3 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the Commonwealth of Pennsylvania (FEMA–4618–DR), dated September 10, 2021, and related determinations.

DATES: This amendment was issued October 13, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the Commonwealth of Pennsylvania is hereby amended to include the following areas among those areas determined to have been adversely affected by the event declared a major disaster by the President in his declaration of September 10, 2021.

Bedford, Philadelphia, and York Counties for Public Assistance (already designated for Individual Assistance).

Fulton, Huntingdon, Luzerne, and Schuylkill Counties for Public Assistance.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050 Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24739 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–3574–EM; Docket ID FEMA–2021–0001]

Louisiana; Amendment No. 1 to Notice of an Emergency Declaration

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This notice amends the notice of an emergency declaration for the State of Louisiana (FEMA–3574–EM), dated September 13, 2021, and related determinations.

DATES: This amendment was issued October 19, 2021.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW, Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that the incident period for this emergency is closed effective September 18, 2021.

The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households In Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.

Deanne Criswell,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2021–24727 Filed 11–12–21; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF HOMELAND SECURITY

Transportation Security Administration

Intent To Request Extension From OMB of One Current Public Collection of Information: TSA End of Course Level 1 Evaluation—Instructor-Led Classroom Training

AGENCY: Transportation Security Administration, DHS.

ACTION: 60-Day notice.

SUMMARY: The Transportation Security Administration (TSA) invites public comment on one currently approved Information Collection Request (ICR), Office of Management and Budget (OMB) control number 1652–0041, that we will submit to OMB for an extension in compliance with the Paperwork Reduction Act (PRA). The ICR describes the nature of the information collection and its expected burden. The collection involves the submission of ratings and written comments about the quality of training instruction from TSA students who successfully complete TSA instructor-led classroom training, including civilian Canine Training Center (CTC) students who graduate from the Explosives Detection Canine Handler Course, Passenger Screening Canine Handler Course, Bridge Course, or the Law Enforcement Supervisors Course.

DATES: Send your comments by January 14, 2022.

ADDRESSES: Comments may be emailed to *TSAPRA@dhs.gov* or delivered to the TSA PRA Officer, Information Technology (IT), TSA–11, Transportation Security Administration, 6595 Springfield Center Drive, Springfield, VA 20598–6011.

FOR FURTHER INFORMATION CONTACT: Christina A. Walsh at the above address, or by telephone (571) 227–2062.

SUPPLEMENTARY INFORMATION:

Comments Invited

In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The ICR documentation will be available at *http://www.reginfo.gov* upon its submission to OMB. Therefore, in preparation for OMB review and approval of the following information collection, TSA is soliciting comments to—

(1) Evaluate whether the proposed information requirement is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agency's estimate of the burden;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the collection of information on those who are to respond, including using appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

Information Collection Requirement

OMB Control Number 1652–0041; TSA End of Course Level 1 Evaluation—Instructor-Led Classroom Training. TSA's CTC delivers instructor-led classroom training, including the Explosives Detection Canine Handler Course, Passenger Screening Canine Handler Course, Bridge Course, and the Law Enforcement Supervisor Course to TSA, and state and local civilian personnel. State and local civilian personnel (primarily, law enforcement agencies that are responsible for the security at airports throughout the United States) participate in this classroom training under agency-specific cooperative agreements with TSA's National Explosives Detection Canine Team Program. This information collection captures ratings and written comments from students about the quality of the training. The CTC collects the evaluation data to determine students' satisfaction with their learning experience and provides it to representatives at both TSA headquarters and at CTC (*e.g.,* to the Branch Manager, Deputy Branch Manager, and CTC instructional staff and supervisors) to improve the course curriculum and course of instruction.

TSA estimates an average of 156 students will complete the evaluations annually. The estimated burden is approximately 30 minutes (0.5 hours) per participant, or total of 78 hours per calendar year to read, answer, and submit the evaluation questions.

Dated: November 9, 2021.

Christina A. Walsh,

TSA Paperwork Reduction Act Officer, Information Technology.

[FR Doc. 2021–24885 Filed 11–12–21; 8:45 am]

BILLING CODE 9110–05–P

DEPARTMENT OF HOMELAND SECURITY

Transportation Security Administration

Extension of Agency Information Collection Activity Under OMB Review: Pipeline Corporate Security Review

AGENCY: Transportation Security Administration, DHS.

ACTION: 30-Day Notice.

SUMMARY: This notice announces that the Transportation Security Administration (TSA) has forwarded the Information Collection Request (ICR), Office of Management and Budget (OMB) control number 1652–0056, abstracted below, to OMB for review and approval of an extension of the currently approved collection under the Paperwork Reduction Act (PRA). The ICR describes the nature of the information collection and its expected burden. The collection encompasses interviews and site visits with pipeline owner/operators regarding company security planning and plan implementation. The collection also involves requirements issued under a TSA Security Directive to address cyber security threats.

DATES: Send your comments by December 15, 2021. A comment to OMB is most effective if OMB receives it within 30 days of publication.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under Review—Open for Public Comments'' and by using the find function.

FOR FURTHER INFORMATION CONTACT: Christina A. Walsh, TSA PRA Officer, Information Technology (IT), TSA–11, Transportation Security Administration, 6595 Springfield Center Drive, Springfield, VA 20598–6011; telephone (571) 227–2062; email *TSAPRA@tsa.dhs.gov.*

SUPPLEMENTARY INFORMATION: TSA published a **Federal Register** notice, with a 60-day comment period soliciting comments, of the following collection of information on August 27, 2021, 86 FR 48239.

Comments Invited

In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The ICR documentation will be available at *http://www.reginfo.gov* upon its submission to OMB. Therefore, in preparation for OMB review and approval of the following information collection, TSA is soliciting comments to—

(1) Evaluate whether the proposed information requirement is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agency's estimate of the burden;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the collection of information on those who are to respond, including using appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

Information Collection Requirement

Title: Pipeline Corporate Security Review (PCSR).

Type of Request: Extension of a currently approved collection.

OMB Control Number: 1652–0056.

Forms(s): Pipeline Corporate Security Review (PCSR) Protocol Form and TSA Forms related to the Security Directive.

Affected Public: Hazardous Liquids and Natural Gas Pipeline Industry.

Abstract: Under the Aviation and Transportation Security Act (ATSA) [1] and delegated authority from the Secretary of Homeland Security, TSA is tasked with developing policies, strategies, and plans for dealing with transportation security. To carry out this responsibility regarding pipelines, TSA assesses current industry security practices through its PCSR program. The PCSR is a voluntary, face-to-face visit with a pipeline owner/operator during which TSA discusses an owner/operator's corporate security planning and the entries made by the owner/operator on the PCSR Form. The PCSR Form includes 210 questions concerning the owner/operator's corporate level security planning, covering security topics such as physical and cyber security, vulnerability assessments, training, and emergency communications. TSA uses the information collected during the PCSR process to determine baseline security standards, potential areas of security vulnerability, and industry ''smart'' practices throughout the pipeline mode.

In addition, on July 19, 2021, TSA issued a Security Directive (SD) imposing mandatory cybersecurity measures on specified owner/operators of critical hazardous liquid and natural pipelines and liquefied natural gas facilities.[2] These owner/operators are required to take several actions requiring a collection of information. First, they must develop and adopt a Cybersecurity Contingency/Response Plan to ensure the resiliency of their operations in the event of a cybersecurity attack. This report must be made available to TSA upon request. Second, they are required to have a third-party complete an evaluation of their industrial control system design and architecture to identify previously unrecognized vulnerabilities. The evaluation must include a final report that must also be made available to TSA upon request. Third, within 7 days of each deadline set forth in the SD, owner/operators must ensure that their Cybersecurity Coordinator or other accountable executive submits a statement to TSA via email certifying that the owner/operator has met the requirements of the SD. For convenience, TSA provides an optional form for each submission deadline that owner/operators can complete and submit via email. To the extent information collected is deemed Sensitive Security Information, TSA will handle the information as required by 49 CFR parts 15 and 1520.

Number of Respondents: 97 respondents annually.

Estimated Annual Burden Hours: 4,423 hours.[3]

Dated: November 9, 2021.

Christina A. Walsh,

TSA Paperwork Reduction Act Officer, Information Technology.

[FR Doc. 2021–24862 Filed 11–12–21; 8:45 am]

BILLING CODE 9110–05–P

[1] Public Law 107–71 (115 Stat. 597; Nov. 19, 2001) codified at 49 U.S.C. 114.

[2] On May 28, 2021, TSA issued another SD which included three information collections. OMB control number 1652–0055, includes two of these information collections, requiring owner/operators to report cybersecurity incidents to CISA, and to designate a Cybersecurity Coordinator, who is required to be available to the TSA 24/7 to coordinate cybersecurity practices and address any incidents that arise, and who must submit contact information to TSA. OMB control number 1652–0050 contains the remaining information collection, requiring owner/operators to conduct a cybersecurity assessment, to address cyber risk, and identify remediation measures that will be taken to fill those gaps and a time frame for achieving those measures.

[3] Since the publication of the 60-day notice, TSA has adjusted the annual burden to show the one-time burden for the mandatory collection: 4,423.333 hours = (12,610 (one-time burden) + 220 (Year 1 annual burden) + 220 (Year 2 annual burden) + 220 (Year 3 annual burden) =13,270 hours, or an annual average of 4,423.33 hours.

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[FR–6289–N–01]

Notice of Intent To Establish a Tribal Intergovernmental Advisory Committee; Request for Comments on Committee Structure

AGENCY: Office of Assistant Secretary for Public and Indian Housing, Department of Housing and Urban Development (HUD).

ACTION: Notice.

SUMMARY: This notice announces HUD's intention to form the Department's first standing Tribal advisory committee. The committee will be called the 'Tribal Intergovernmental Advisory Committee' (TIAC). This notice also solicits comments and recommendations regarding the establishment and structure of the TIAC. The TIAC will be made up of a diverse group of duly elected Tribal leaders representing small, medium, and large federally recognized Tribes. The TIAC is intended to further communications between HUD and federally recognized Tribes on HUD programs, make recommendations to HUD regarding current program regulations, provide advice in the development of HUD's American Indian and Alaska Native (AIAN) housing priorities, and encourage peer learning and capacity building among Tribes and non-Tribal entities. Consistent with HUD's Tribal Government-to-Government Consultation Policy, this notice solicits input on the proposed structure of the TIAC.

DATES: *Comments on the proposed structure of the TIAC are due on or before:* January 14, 2022.

ADDRESSES: Interested persons are invited to submit comments on the structure of the TIAC. Comments may be submitted to HUD electronically. All submissions must refer to the above docket number and title.

Electronic Submission of Comments. Interested persons may submit comments electronically through the Federal eRulemaking Portal at *www.regulations.gov.* Electronic submission allows the maximum time to prepare and submit comments, ensures timely receipt by HUD, and enables HUD to make them immediately available to the public. Comments submitted electronically through the *www.regulations.gov* website can be viewed by interested members of the public. Individuals should follow the instructions provided on that website to submit comments.

Note: To receive consideration, comments must be submitted electronically through *www.regulations.gov* and refer to the above docket number and title. Comments should not be submitted by mail.

No Facsimile Comments. Facsimile (FAX) comments will not be accepted.

Public Inspection of Comments. All properly submitted comments and communications submitted to HUD will be available for public inspection and copying between 8:00 a.m. and 5:00 p.m. weekdays at the above address. Due to security measures at the HUD Headquarters building, an advance appointment to review the submissions must be scheduled by calling the

Regulations Division at (202) 708–3055 (this is not a toll-free number). Individuals with speech or hearing impairments may access this number via TTY by calling the toll-free Federal Information Relay Service at (800) 877–8339. Copies of all submissions are available for inspection and downloading at *www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Heidi J. Frechette, Deputy Assistant Secretary for Native American Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW, Room 4108, Washington, DC 20410–5000, telephone (202) 402–7598 (this is not a toll-free number). Individuals with speech or hearing impairments may access this number via TTY by calling the toll-free Federal Information Relay Service at (800) 877–8339.

SUPPLEMENTARY INFORMATION:

I. Background

Consistent with Executive Order 13175,[1] HUD's Tribal Government-to-Government Consultation Policy recognizes the right of Indian tribes to self-governance and supports Tribal sovereignty and self-determination.[2] It provides that HUD will engage in regular and meaningful consultation and collaboration with Tribal officials in the development of Federal policies that have Tribal implications. Executive Order 13175 also requires Federal agencies to advance Tribal self-governance and ensure that the rights of sovereign Tribal governments are fully respected by conducting open and candid consultations.

In 2016, in furtherance of Executive Order 13175, HUD proposed the establishment of a TIAC. On June 23, 2016, HUD published a **Federal Register** Notice seeking comments on the structure of the proposed TIAC.[3] On December 21, 2016, HUD published a second **Federal Register** Notice announcing the establishment of the TIAC and requesting nominations from duly elected or appointed Tribal leaders to serve on the TIAC.[4] HUD received nominations from various Tribes but did not receive an adequate number of nominations to fully constitute the TIAC. Accordingly, HUD did not complete the establishment of the TIAC at that time.

On January 26, 2021, President Biden issued a Presidential Memorandum on Tribal Consultation and Strengthening Nation-to-Nation Relationships.[5] The memorandum directed all Federal agencies to take actions to strength their Tribal consultation policies and practices and to further the purposes of Executive Order 13175.

To further enhance consultation and collaboration with Tribal governments, HUD is once again proposing to establish the TIAC. Several Federal agencies have established similar Tribal advisory committees. These advisory committees convene periodically during the year to exchange information with agency staff, notify Tribal leaders of activities or policies that could affect Tribes, and provide guidance on consultation. HUD has determined that a similar advisory committee would provide critical support to the Department as it formulates. The formation of the TIAC would also assist the Department in carrying out its responsibilities under the Presidential Memorandum on Tribal Consultation and Strengthening Nation-to-Nation Relationships.

Prior to HUD's establishment of the TIAC, this notice solicits input into the structure of the committee.

II. Proposed Structure of the TIAC

To assist commenters with their review and to help them provide feedback, HUD is providing the following as an example of how the TIAC may be structured. HUD is requesting comments on the following proposed structure of the TIAC and is open to any additional recommendation on how the TIAC may be constituted and how it should operate. Comments on the structure of the TIAC are due on or before: January 14, 2022

A. Purpose and Role of the TIAC

The purposes of the TIAC are:

(1) To further facilitate intergovernmental communication between HUD and Tribal leaders of federally recognized Tribes on all HUD programs;

(2) To make recommendations to HUD regarding current program regulations that may require revision, as well as suggest rulemaking methods to develop such changes. The TIAC will not, however, negotiate any changes to regulations that are subject to negotiated rulemaking under Section 106 of the Native American Housing Assistance and Self-Determination Act (NAHASDA) and will not serve in place of any future negotiated rulemaking committee established by HUD; and

(3) To advise in the development of HUD's AIAN housing priorities.

The role of the TIAC is to provide recommendations and input to HUD, and to provide a vehicle for regular, meaningful consultation and collaboration with Tribal officials. It will not replace other means of Tribal consultations, but, rather, will supplement them. HUD will maintain the responsibility to exercise program management, including the drafting of HUD notices, guidance documents, and regulations.

B. Charter and Protocols

The TIAC will develop its own ruling charter and protocols. HUD will provide staff for the TIAC to act as a liaison between TIAC and HUD officials, manage meeting logistics, and provide general support for TIAC activities.

C. Meetings and Participation

Subject to availability of Federal funding, the TIAC will meet periodically to discuss agency policies and activities with HUD, set shared priorities, and facilitate further consultation with Tribal leaders. Initially, meetings will likely be conducted virtually, but may be in person in the future, and will be conducted consistent with any COVID–19 safety protocols. HUD will pay for these meetings, including the member's cost to travel to these meetings. The TIAC may meet on a more frequent basis virtually, via conference calls, videoconferences, or through other forms of communication. Additional in-person meetings may be scheduled at HUD's discretion in the future. Participation at TIAC meetings will be limited to TIAC members or their alternates. Alternates must be designated in writing by the member's Tribal government to act on their behalf. TIAC members may bring one technical advisor to the meeting at their expense. The technical advisor can advise the member but cannot speak in the member's place. Meeting minutes will be available on the HUD website, and, depending on the circumstances, public and Tribal comments may be requested.

D. TIAC Membership

The TIAC will be comprised of HUD representatives and Tribal delegates from across the country, representing small, medium, and large tribes. The TIAC will be composed of HUD officials

[1] Executive Order 13175, 65 FR 67249 (November 9, 2000).

[2] Tribal Government-to-Government Consultation Policy, 81 FR 40893 (June 23, 2016).

[3] Notice of Proposal To Establish a Tribal Intergovernmental Advisory Committee; Request for Comments on Committee Structure, 81 FR 40899 (June 23, 2016).

[4] Establishment of Tribal Intergovernmental Advisory Committee; Request for Nominations for Tribal Intergovernmental Membership, 81 FR 93700 (December 21, 2016).

[5] The memorandum was published in the **Federal Register** on January 29, 2021 (86 FR 7491).

(including the Secretary or his or her designee, as well as the Assistant Secretaries for Office of Public and Indian Housing (PIH), Office of Policy, Development, and Research (PD&R), Office of Fair Housing and Equal Opportunity (FHEO), Office of Field Policy Management (FPM), Office of Housing (FHA), Government National Mortgage Association (Ginnie Mae), and Office of Community Planning and Development (CPD) or their designees) and up to fifteen Tribal delegates. Up to two Tribal delegates will represent each of the six HUD ONAP regions. Up to three remaining Tribal delegates will serve at-large. Only duly elected or appointed Tribal leaders may serve as TIAC delegates or alternates of the TIAC. The Secretary of HUD will appoint the HUD representatives of the TIAC. TIAC Tribal delegates will serve a term of two years. To ensure consistency between Tribal terms, delegates will have a staggered term of appointment. In order to establish a staggered term of appointment, half of the Tribal delegates appointed in the inaugural year of the TIAC will serve two years and the other half will serve three years. Tribal delegates must designate their preference to serve two or three years; however, HUD will make the final determination on which Tribal delegates will serve two or three years. Once these Tribal delegates complete these initial terms, future Tribal delegates will serve terms that last two years. Should a delegate's tenure as a Tribal leader come to an end during their appointment to the TIAC, the delegate's Tribe will nominate a replacement, if not the already nominated alternate.

E. Function

The establishment of the TIAC is intended to enhance government-to-government relationships, communications, and mutual cooperation between HUD and Tribes. It is not intended to, and will not, create any right to administrative or judicial review, or any other right or benefit or trust responsibility, substantive or procedural, enforceable by a party against the United States, its agencies or instrumentalities, its officers or employees, or any other persons.

Dominique Blom,

General Deputy Assistant, Secretary for Public and Indian Housing.

[FR Doc. 2021–24818 Filed 11–12–21; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

[222A2100DD/AASS003600/ A0T902020.999900.253G]

Liquor Control Ordinance; Catawba Indian Nation

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice.

SUMMARY: This notice publishes the liquor control ordinance of the Catawba Indian Nation. The liquor control statute regulates and controls the sale, purchase, transportation, manufacture, consumption, and possession of alcoholic beverages on the trust lands of the Catawba Indian Nation [previously known as Catawba Tribe of South Carolina].

DATES: This Amendment is effective December 15, 2021.

FOR FURTHER INFORMATION CONTACT: Ms. Rebecca J. Smith, Tribal Relations Specialist, Eastern Regional Office, Bureau of Indian Affairs, 545 Marriott Drive, Suite 700, Nashville, Tennessee 37214, Telephone: (615) 564–6711, Fax: (615) 564–6701.

SUPPLEMENTARY INFORMATION: Pursuant to the Act of August 15, 1953, Public Law 83–277, 67 Stat. 586, 18 U.S.C. 1161, as interpreted by the Supreme Court in *Rice* v. *Rehner,* 463 U.S. 713 (1983), the Secretary of the Interior shall certify and publish in the **Federal Register** notice of adopted liquor control ordinances for the purpose of regulating liquor transactions in Indian country. The Nation's General Council of the Catawba Indian Nation duly adopted the Nation's Alcoholic Beverage Control Ordinance on May 1, 2021.

This notice is published in accordance with the authority delegated by the Secretary of the Interior to the Assistant Secretary—Indian Affairs. I certify that the Nation's General Council of the Catawba Indian Nation duly adopted by The General Council of the Catawba Indian Nation duly adopted the Catawba Indian Nation's Alcoholic Beverage Control Ordinance on May 1, 2021.

The Catawba Indian Nation Alcoholic Beverage Control Ordinance reads as follows:

Catawba Indian Nation

Regulation of Alcoholic Beverages

Article 1—General Provisions

Sec. 18B–100.—General Prohibition and Purpose

(a) This Ordinance is intended to establish a uniform system of control over the sale, purchase, transportation, manufacture, consumption, and possession of alcoholic beverages on the trust lands of the Catawba Indian Nation, and to provide procedures to insure the proper administration of the tribal laws regulating alcoholic beverages. This Ordinance shall be liberally construed to the end that the sale, purchase, transportation, manufacture, consumption, and possession of alcoholic beverages shall be prohibited except as authorized in this Ordinance.

(b) The introduction, transportation, sale, or possession of intoxicating beverages shall be lawful within the Indian country of the Catawba Indian Nation, provided that such introduction, transportation, sale or possession conforms in all respects to the laws of both the State in which it occurs and the Catawba Indian Nation, as both may be amended from time to time. Any Tribal laws, resolutions or ordinances heretofore enacted which prohibit the introduction, advertisement, sale or possession of intoxicating beverages within the Indian country of the Catawba Indian Nation are hereby repealed.

Sec. 18B–101.—Definitions

As used in this Ordinance, unless the context requires otherwise:

(1) ''Tribal ABC law'' or ''Tribal ABC laws'' means any provision in this Ordinance, and the rules issued by the Commission under the authority of this Ordinance.

(2) ''Tribal ABC permit'' or ''permits'' means any written or printed authorization issued by the Commission pursuant to the provisions of this Ordinance. Unless the context clearly requires otherwise, as in the provisions concerning applications for permits, ''ABC permit'' or ''permit'' means a presently valid permit.

(3) ''Alcoholic beverage'' means any beverage containing at least one-half of one percent alcohol by volume, including malt beverages, unfortified wine, fortified wine, spirituous liquor, and mixed beverages.

(4) [Reserved for future codification purposes.]

(5) ''Commission'' means the Tribal Alcoholic Beverage Control Commission (''TABCC'').

(6) ''Fortified wine'' means any wine, of more than 16 percent and no more than 24 percent alcohol by volume, made by fermentation from grapes, fruits, berries, rice, or honey; or by the addition of pure cane, beet, or dextrose sugar; or by the addition of pure brandy from the same type of grape, fruit, berry, rice, or honey that is contained in the

base wine and produced in accordance with the regulations of the United States.

(7) ''Malt beverage'' means beer, lager, malt liquor, ale, porter, and any other brewed or fermented beverage except unfortified or fortified wine as defined by this Ordinance, containing at least one-half of one percent, and not more than 15 percent, alcohol by volume. Any malt beverage containing more than six percent alcohol by volume shall bear a label clearly indicating the alcohol content of the malt beverage.

(8) ''Mixed beverage'' means either of the following: a. A drink composed in whole or in part of spirituous liquor and served in a quantity less than the quantity contained in a closed package. b. A premixed cocktail served from a closed package containing only one serving.

(9) ''Nontaxpaid alcoholic beverage'' means any alcoholic beverage upon which the taxes imposed by the United States, the Catawba Indian Nation, or any other territorial jurisdiction in which the alcoholic beverage was purchased have not been paid.

(10) ''Permittee'' means a person who receives a Tribal ABC permit.

(11) ''Person'' means an individual, firm, partnership, association, corporation, limited liability company, other organization or group, or other combination of individuals acting as a unit.

(12) ''Premises'' means any facility licensed hereunder including, without limitation, any tribal gaming facility.

(13) ''Sale'' means any transfer, trade, exchange, or barter, in any manner or by any means, for consideration.

(14) ''Spirituous liquor'' or ''liquor'' means distilled spirits or ethyl alcohol, including spirits of wine, whiskey, rum, brandy, gin and all other distilled spirits and mixtures of cordials, liqueur, and premixed cocktails, in closed containers for beverage use regardless of their dilution.

(15) [Reserved for future codification purposes.]

(16) ''Unfortified wine'' means any wine of 16 percent or less alcohol by volume made by fermentation from grapes, fruits, berries, rice, or honey; or by the addition of pure cane, beet, or dextrose sugar; or by the addition of pure brandy from the same type of grape, fruit, berry, rice, or honey that is contained in the base wine and produced in accordance with the regulations of the United States.

Sec. 18B–102.—Manufacture, Sale, etc., Forbidden Except as Expressly Authorized

(a) General prohibition. It shall be a violation for any person to manufacture, sell, transport, import, deliver, furnish, purchase, consume, or possess any alcoholic beverages except as authorized by the Tribal ABC law.

(b) Violation. Unless a different punishment is otherwise expressly stated, any person who violates any provision of this Ordinance shall be subject to a civil fine in an amount not less than $250 and not more than $5,000 for each violation.

Secs. 18B–103, 18B–104.—Reserved

Sec. 18B–105.—Advertising

General Rule. No person shall advertise alcoholic beverages on Tribal trust land except in compliance with the rules of the Commission.

Secs. 18B–106—18B–108.—Reserved

Sec. 18B–109.—Shipping of Products for Resale

No person shall have malt beverages or unfortified wine shipped directly from a point outside the state to a destination within the Catawba Indian Nation for resale within the Indian country of the Catawba Indian Nation.

Sec. 18B–110.—Emergency

When the Chief of the Catawba Indian Nation finds that a ''state of emergency,'' as defined by Tribal law, exists anywhere on Tribal land, he may order the cessation of all sales, transportation, manufacture, and bottling of alcoholic beverages.

The Chief's order shall apply in those portions of Tribal land designated in the order, for the duration of the state of emergency. Any order by the Chief under this section shall be directed to the Chairman of the Commission.

Sec. 18B–111.—Nontaxpaid Alcoholic Beverages

No person may possess, transport, or sell nontaxpaid alcoholic beverages except as authorized by the Tribal ABC law.

Sec. 18B–112.—Tribal Alcoholic Beverage Control

(a) The Tribal Alcoholic Beverage Control Commission shall possess the same powers and authority within the Indian country of the Catawba Indian Nation as conveyed upon state administrative agencies that regulate alcoholic beverages.

(b) Alcoholic beverages which may be sold. No alcoholic beverage may be sold on Indian country lands under the jurisdiction of the Catawba Indian Nation pursuant to this section which has not been approved for sale in the state in which the sale occurs.

(c) Establishment of a Tribal Commission. The Tribal Commission shall have authority to issue ABC permits to retail and commercial establishments, located wholly within the Indian country of the Catawba Indian Nation, and to regulate the purchase, possession, consumption, sale, and delivery of alcoholic beverages at permitted outlets and premises. The fees generated by the Tribal Alcoholic Beverage Control Commission for the issuance of retail permits may be retained by the Catawba Indian Nation to offset costs of operating the Tribal Alcoholic Beverage Control Commission.

(d) Establishment of rules. The Tribal Alcoholic Beverage Control Commission shall adopt state rules regulating retail outlet activity as may be required under applicable law, and such rules may be site-specific.

(e) Recognition of Applicable State Authority. The Tribal Alcoholic Beverage Control Commission has the authority to enter into agreements with states to provide for the sale, delivery, and distribution of spirituous liquor to the Tribal Alcoholic Beverage Control Commission. When required and able to do so under applicable law, the Tribal Alcoholic Beverage Control Commission shall purchase spirituous liquor for resale by the Tribal Alcoholic Beverage Control Commission exclusively from the state or state-approved vendors at the same price and on the same basis that such spirits are purchased by local entities. To the extent there is a conflict between the Tribal Alcoholic Beverage Control Commission's authority or purpose and the state's authority or purpose, the state's authority or purpose shall prevail, to the extent there is no conflict of law as provided in subsection (i) below.

(f) Discrimination. The Tribal Alcoholic Beverage Control Commission shall not discriminate against non-Indians in the application of the Tribal ABC law. Non-Indians shall be entitled to apply for and receive ABC permits in the same manner as an Indian on Indian country lands under the jurisdiction of the Catawba Indian Nation.

(g) Resolution of Contested Cases. If the Tribal Alcoholic Beverage Control Commission levies a fine, or suspends or revokes a permit pursuant to applicable law for a violation of the provisions applicable to the Catawba Indian Nation in this section, the permittee shall have the right of appeal of an agency final decision of the Tribal

Commission to the Tribal Courts, if formed at the time of the Commission's final decision. Any further appeal shall be to the appellate courts of the Nation, if formed. In the absence of a Tribal Court, appeal shall be had to the Executive Committee, the results of which appeal shall be final. All fines paid to the Tribal Commission in satisfaction of any penalty assessed by the Tribal Commission may be retained by the Catawba Indian Nation to offset costs of operating the Tribal Alcoholic Beverage Control Commission.

(h) Failure to comply with state law. The Nation shall conform to future amendments to state law as may be required by 18 U.S.C. 1161.

(i) Conflict of laws. The Nation does not believe any provision of this Ordinance or the application of any related state law presents a conflict with federal law. In the event such conflict arises, this Ordinance shall be interpreted in a manner that resolves the conflict in favor of applicable federal law.

Secs. 18B–113—18B–119.—Reserved

Sec. 18B–120.—Additional Definitions

As used in this Article:

(1) ''Aggrieved party'' means a person who sustains an injury as a consequence of the actions of the underage person, but does not include the underage person or a person who aided or abetted in the sale or furnishing to the underage person.

(2) ''Injury'' includes, but is not limited to, personal injury, property loss, loss of means of support, or death. Damages for death shall be determined by the Court. Nothing in subdivision (1) of this section shall be interpreted to preclude recovery under this Article for loss of support or death on account of injury to or death of the underage person or a person who aided or abetted in the sale or furnishing to the underage person.

(3) ''Underage'' person means a person who is less than the age legally required for purchase of the alcoholic beverage in question.

(4) ''Vehicle'' shall have the same meaning as prescribed by North Carolina G.S § 20–4.01(49).

Sec. 18B–121.—Claim for Relief Created for Sale to Underage Person

An aggrieved party has a claim for relief for damages, in the Nation's courts, if formed, against a permittee if:

(1) The permittee or his agent or employee negligently sold or furnished an alcoholic beverage to an underage person; and

(2) The consumption of the alcoholic beverage that was sold or furnished to an underage person caused or contributed to, in whole or in part, an underage driver's being subject to an impairing substance, as defined in the laws of the state where the beverage was sold or furnished, at the time of the injury; and

(3) The injury that resulted was proximately caused by the underage driver's negligent operation of a vehicle while so impaired.

Sec. 18B–122.—Burden of Proof and Admissibility of Evidence

The plaintiff shall have the burden of proving that the sale or furnishing of the alcoholic beverage to the underage person, as defined, was, under the circumstances, negligent. Proof of the sale or furnishing of the alcoholic beverage to an underage person, as defined, without request for identification shall be admissible as evidence of negligence. Proof of good practices (including but not limited to, instruction of employees as to laws regarding the sale of alcoholic beverages, training of employees, enforcement techniques, admonishment to patrons concerning laws regarding the purchase or furnishing of alcoholic beverages, or detention of a person's identification documents in accordance with Section 18B–129 and inquiry about the age or degree of intoxication of the person), evidence that an underage person misrepresented his age, or that the sale or furnishing was made under duress is admissible as evidence that the permittee was not negligent.

Sec. 18B–123.—Limitation on Damages

The total amount of damages that may be awarded to all aggrieved parties pursuant to any claims for relief under this Article is limited to no more than $500,000.00 per occurrence. When all claims arising out of an occurrence exceed $500,000.00, each claim shall abate in the proportion it bears to the total of all claims.

Sec. 18B–124.—Joint and Several Liability

The liability of the negligent driver or owner of the vehicle that caused the injury and the permittee which sold or furnished the alcoholic beverage shall be joint and several, with right of contribution but not indemnification.

Sec. 18B–125.—Reserved

Sec. 18B–126.—Statute of Limitations

The statute of limitations is three years from the date of the injury.

Secs. 18B–127, 18B–128.—Reserved

Sec. 18B–129.—No Liability for Refusal to Sell or for Holding Documents

(a) No permittee or his agent or employee may be held liable for damages resulting from the refusal to sell or furnish an alcoholic beverage to a person who fails to show proper identification as described in Section 18B–302(d), or who appears to be an underage person.

(b) No permittee or his agent or employee may be held civilly liable if the permittee or his agent or employee holds a customer's identification documents for a reasonable length of time in a good faith attempt to determine whether the customer is of legal age to purchase an alcoholic beverage, provided the permittee or his agent or employee informs the customer of the reason for his actions.

Secs. 18B–130—18B–199.—Reserved

Article 2—Administration

Sec. 18B–200.—Tribal Alcoholic Beverage Control Commission

(a) Creation of Commission; compensation. The Tribal Alcoholic Beverage Control Commission shall consist of at least three members: One Chairman and two associate members. The Commissioners shall receive compensation and benefits at a level determined by Executive Committee resolution. This compensation shall be included in the Commission's annual budget. Commissioners shall be reimbursed for actual expenses incurred on Commission business, including necessary travel expenses.

(b) Appointment of members. Members of the Commission shall be nominated by the Chief and confirmed by the Executive Committee by written resolution. Each member's term shall begin on the date of such resolution. At least one seat must be filled by a Catawba citizen.

(c) Nominees to the Commission shall be selected on the basis of their commitment to the interests and goals of the Commission without forgetting the interests of the Catawba Indian Nation community, their preparedness to assume responsibility for the decisions of the Commission and to ensure that said decisions are implemented, and their willingness to devote the time and energy necessary to familiarize themselves with the strategic, financial and operational issues facing the Commission.

(d) Terms of members. Commission member shall initially serve for one, two, and three-year terms. Thereafter, each Commission member shall serve

for a three-year term. The Commissioner shall elect their own officers at the start of each fiscal year. A Commission member may be removed for cause by a majority vote of the Executive Committee. Nothing in this ordinance shall be construed to preclude a member of the Commission from serving successive terms.

(e) Vacancy. The Chief shall fill any vacancy on the Commission by appointing a successor within 30 days after the date on which the vacancy becomes effective subject to approval by Executive Committee. If the Chairman's seat becomes vacant, the Vice Chairman shall immediately assume the Chairman's seat and complete the remaining term of the vacating Chairman. A new member of the Commission will be appointed by the Chief, subject to approval by Executive Committee, to complete the remaining term of the former Vice Chairman. The Commission will then elect a new Vice Chairman.

(f) Employees. The chairman is authorized to employ, discharge, and otherwise supervise subordinate personnel of the Commission.

(g) Independence. The Commission shall be an independent agency. No prior or subsequent review by the Chief, Executive Committee, the Nation's Gaming Commission or the Nation's gaming enterprises shall be required or permitted, except as otherwise explicitly provided in this ordinance.

(h) Sovereign Immunity of the Commission. The Commission, as an instrumentality of the Nation, retains all of the Nation's rights, privileges and immunities, including sovereign immunity from suit.

(i) Oath of Office. Prior to beginning their official duties, each member of the Commission shall take the following oath before some officer authorized to administer oaths: ''I do solemnly swear (or affirm) that I will faithfully execute the duties of Commissioner as a member of the Tribal Alcoholic Beverage Control Commission and will to the best of my ability, preserve, protect and defend the constitution and governing document and laws confirmed and ratified by the enrolled members of the Catawba Indian Nation. I do solemnly swear (or affirm) that I have not obtained my appointment to this Commission by bribery or any undue or unlawful means or fraud, and that in all measures which may come before me, I will so conduct myself as in my judgment shall appear most conductive to the interest and prosperity of the Catawba Indian Nation.''

(j) All Commissioners will be subject to initial and subsequent random drug testing per the Tribal personnel policy. Refusal to submit to any drug testing or a positive test result shall result in an immediate dismissal from the Commission. Drug testing shall be paid from the annual budget of the Commission.

(k) All Commissioners are subject to the same criminal background checks as members of the Nation's Gaming Commission. Each Commissioner is required to update their information.

Sec. 18B–201.—Conflict of Interest

(a) Financial interests restricted. No person shall be appointed to or employed by the Commission if that person or a member of that person's family related to that person by blood or marriage to the first degree has or controls, directly or indirectly, a financial interest in any commercial alcoholic beverage enterprise, including any business required to have a Tribal ABC permit. The Commission may exempt from this provision any person, other than a Commission member, when the financial interest in question is so insignificant or remote that it is unlikely to affect the person's official actions in any way. Exemptions may be granted only to individuals, not to groups or classes of people, and each exemption shall be in writing, be available for public inspection, and contain a statement of the financial interest in question. For purposes of this Section 18B–201, Tribal membership and the receipt of benefits from the Nation as a citizen shall not be construed as a ''financial interest.''

(b) Self-dealing. The Commission shall not contract or otherwise deal in any business matter so that a member in any way benefits, directly or indirectly, from the transaction.

(1) No Commission member may have a financial interest in any operation or entity licensed, permitted, or otherwise authorized pursuant to this ordinance. However, nothing in this section shall prohibit any Commission member from having a financial interest as would any citizen of the Nation, if entitled to such interest as a citizen of the Nation.

(2) No Commission member shall accept any gift or other thing of value from any applicant, licensee, or permittee under this ordinance, except for non-monetary gifts of insignificant value received in the ordinary course of business or food and refreshments customarily made available in the ordinary course of meetings.

(c) Dealing for family members. Neither the Commission shall contract or otherwise deal in any business matter so that a member's spouse or any person related to him by blood to a degree of first cousin or closer in any way benefits, directly or indirectly, from the transaction unless:

(1) The member whose relative benefits from the transaction abstains from participating in any way, including voting, in the decision;

(2) The minutes of the meeting at which the final decision is reached specifically note the member whose spouse or relative is benefited and the amount involved in each transaction; and

(3) The next annual audit of the Commission or local board specifically notes the member and the amount involved in each transaction occurring during the year covered by the audit.

Sec. 18B–202.—Reserved

Sec. 18B–203.—Powers and Duties of the Commission

(a) Powers. The Commission shall have authority to:

(1) Administer the Tribal ABC laws;

(2) Provide for enforcement of the Tribal ABC laws, in conjunction with state regulatory authorities;

(3) Issue ABC permits as allowed under this Ordinance;

(4) Adopt rules and procedures for the issuance and enforcement of ABC permits;

(5) Administer an annual budget with said budget to be approved annually by the Executive Committee;

(6) Act as the distributor of all alcohol on Tribal trust lands. Spirituous liquor and fortified wine shall be purchased by TABCC according to applicable law. Malt beverages and unfortified wine shall be purchased from state-authorized distributors and may be redistributed from a TABCC warehouse or authorized to be delivered directly to TABCC authorized permittee, within the Indian country of the Catawba Indian Nation if authorized to do so under applicable law; and

(7) Issue any retail ABC license or permit issued by state regulatory agencies, including a temporary license or permit. Negotiate and enter into contract with state regulatory agencies for purchase of spirituous liquor and fortified wine; and

(8) Adopt fiscal control rules concerning the borrowing of money, maintenance of working capital, investments, appointment of a financial officer, the daily deposit of funds and any other rules necessary to assure the proper accountability of public funds.

(b) Implied powers. The Commission shall have all other powers which may be reasonably implied from the granting of the express powers stated in subsection (a), or which may be

incidental to, or convenient for, performing the duties given to the Commission.

Sec. 18B–204.—Reserved

Sec. 18B–205.—Accounts, Reports and Audits Required

(a) Accounts and reports. The Commission shall be required to submit to Executive Committee and to the Chief such reports as may be required by Executive Committee.

(b) Annual independent audit. The Commission shall engage independent auditors for annual audits of its internal operations. Such independent audits must apply generally accepted accounting principles.

Secs. 18B–206—18B–299.—Reserved

Article 3—Sale, Possession, and Consumption

Sec. 18B–300.—Purchase, Possession and Consumption of Malt Beverages, Fortified and Unfortified Wine, Mixed Beverages and Spirituous Liquors

Generally. Except as otherwise provided in this Ordinance, the purchase, consumption, and possession of malt beverages, fortified and unfortified wine, mixed beverages and spirituous liquors by individuals 21 years old and older for their own use is permitted upon any licensed Premises without restriction. All alcoholic beverages sold upon any licensed Premises must be consumed or disposed of upon these premises. No off-premises sale of alcoholic beverages from a permittee is allowed.

Sec. 18B–301.—Reserved

Sec. 18B–302.—Sale to or Purchase by Underage Persons

(a) Sale. It shall be a violation for any person to:

(1) Sell malt beverages or unfortified wine to anyone less than 21 years old; or

(2) Sell fortified wine, spirituous liquor, or mixed beverages to anyone less than 21 years old.

(a1) Give. It shall be a violation for any person to:

(1) Give malt beverages or unfortified wine to anyone less than 21 years old; or

(2) Give fortified wine, spirituous liquor, or mixed beverages to anyone less than 21 years old.

(b) Purchase, possession, or consumption. It shall be a violation for:

(1) A person less than 21 years old to purchase, to attempt to purchase, or to possess malt beverages or unfortified wine; or

(2) A person less than 21 years old to purchase, to attempt to purchase, or to possess fortified wine, spirituous liquor, or mixed beverages; or

(3) A person less than 21 years old to consume any alcoholic beverage.

(c) Aider and abettor.

(1) By underage person. Any person who is under the lawful age to purchase and who aids or abets another in violation of subsection (a), (a1), or (b) of this section shall be in violation of this ordinance.

(2) By person over lawful age. Any person who is over the lawful age to purchase and who aids or abets another in violation of subsection (a), (a1), or (b) of this section shall be in violation of this ordinance.

(d) Defense. It shall be a defense to a violation of subsection (a) of this section if the seller:

(1) Shows that the purchaser produced a tribal identification card, state identification card, a military identification card, or a passport, showing his age to be at least the required age for purchase and bearing a physical description of the person named on the card reasonably describing the purchaser; or

(2) Produces evidence of other facts that reasonably indicated at the time of sale that the purchaser was at least the required age.

(e) Fraudulent use of identification. It shall be a violation for any person to enter or attempt to enter a place where alcoholic beverages are sold or consumed, or to obtain or attempt to obtain alcoholic beverages, or to obtain or attempt to obtain permission to purchase alcoholic beverages, in violation of subsection (b) of this section, by using or attempting to use any of the following:

(1) A fraudulent or altered driver's license.

(2) A fraudulent or altered identification document other than a driver's license.

(3) A driver's license issued to another person.

(4) An identification document other than a driver's license issued to another person.

(5) Any other form or means of identification that indicates or symbolizes that the person is not prohibited from purchasing or possessing alcoholic beverages under this section.

(f) Allowing use of identification. It shall be a violation for any person to permit the use of the person's driver's license or any other form of identification of any kind issued or given to the person by any other person who violates or attempts to violate subsection (b) of this section.

(g) Report sent to Division of Motor Vehicles. The Commission shall file a report with the appropriate state Division of Motor Vehicles indicating the name of the person found to have violated this section and any other information requested by the Division if the person is found to have committed any of the following violations:

(1) A violation of subsection (e) or (f) of this section.

(2) A violation of subsection (c) of this section.

(3) A violation of subsection (b) of this section, if the violation occurred while the person was purchasing or attempting to purchase an alcoholic beverage.

(4) A violation of subsection (a1) of this section.

(h) Handling in course of employment. Nothing in this section shall be construed to prohibit an underage person from selling, transporting, possessing or dispensing alcoholic beverages in the course of employment, if the employment of the person for that purpose is lawful under applicable youth employment statutes and Commission rules.

Sec. 18B–302.1.—Penalties for Certain Offenses Related to Underage Persons

(a) A violation of Section 18B–302(a) or (a1). A person found to have violated Section 18B–302(a) or (a1) must pay a fine of at least $250.00, with the amount of such fine increasing by $250 for all prior violations incurred during the preceding two years from the date of the violation.

(b) A violation of Section 18B–302(c)(2). A person found to have violated Section 18B–302(c)(2) must pay a fine of at least $500.00, with the amount of such fine increasing by $500 for all prior violations incurred during the preceding three years from the date of the violation.

Secs. 18B–303, 18B–304.—Reserved

Sec. 18B–305.—Other Prohibited Sales

(a) Sale to intoxicated person. It shall be a violation for a permittee or his employee to knowingly sell or give alcoholic beverages to any person who is intoxicated.

(b) Discretion for seller. Any person authorized to sell alcoholic beverages under this Ordinance may, in his discretion, refuse to sell to anyone. It shall be a violation for any person to knowingly buy alcoholic beverages for someone who has been refused the right to purchase under this subsection.

(c) Notwithstanding subsection (b) of this section, no permittee may refuse to sell alcoholic beverages to a person

solely based on that person's race, religion, color, national origin, sex, or disability.

Sec. 18B–306.—Sale and Consumption at Casinos and Hotels

It shall be lawful to possess and consume any alcoholic beverage that is purchased in any room of a licensed casino while a casino game, raffle game or bingo game is being conducted in that room so long as all Class II and Class III games being conducted are within the lawful authority of the Indian Gaming Regulatory Act (IGRA) and the federally approved Tribal-state compact and all amendments thereto.

Secs. 18B–307—18B–399.—Reserved

Article 4—Reserved

Article 5—Enforcement

Sec. 18B–500.—Tribal Alcohol Enforcement Agents

(a) Appointment. The TABCC may appoint a Chief Tribal alcohol enforcement agent. The Chair of the TABCC or the Chair's designee shall have the authority to supervise day-to-day activities of the Chief alcohol law-enforcement agent or the Chair's designee. The Chief Tribal alcohol enforcement agent may appoint, with the approval of the TABCC, Tribal alcohol law-enforcement agents and other enforcement personnel. Tribal alcohol law-enforcement agents shall be designated as ''Tribal alcohol enforcement agents.''

(b) Subject matter jurisdiction. After taking the oath prescribed for a peace officer, a Tribal alcohol enforcement agent shall have authority to take all investigatory actions and refer any criminal offenses to appropriate law enforcement authorities for further investigation and prosecution.

(c) Territorial jurisdiction. A Tribal alcohol enforcement agent is a Tribal officer with jurisdiction throughout the Indian country of the Catawba Indian Nation.

(d) Service of commission orders. Tribal alcohol enforcement agents may serve and execute notices, orders, or demands issued by the TABCC for the surrender of permits or relating to any administrative proceeding. While serving and executing such notices, orders, or demands, alcohol law-enforcement agents shall have all the power and authority to request the assistance of appropriate law enforcement authorities in the event criminal conduct is suspected and arrests are anticipated.

Secs. 18B–501—18B–599.—Reserved

Article 6—Reserved

Article 7—Sales

Sec. 18B–700—Retail Sale of Alcoholic Beverages

Spirituous liquor, fortified and unfortified wine and malt beverages may be offered for retail sale only under the provisions of a permit issued by TABCC as authorized by the provisions of this ordinance. TABCC shall operate any retail spirituous and fortified wine store that may in the future be authorized. TABCC shall also be authorized to operate a retail malt beverage and unfortified wine store, subject to applicable law.

Secs. 18B–701—18B–799.—Reserved

Article 8—Operation of ABC Warehouse

Sec. 18B–800.—Purchase From State Until Tribe Establishes Wholesale Distribution System

All alcoholic beverages authorized to be sold shall be purchased by the permittee from TABCC or as directed by TABCC.

Secs. 18B–801—18B–803.—Reserved

Sec. 18B–804.—Alcoholic Beverage Pricing

The uniform pricing of spirits sold to permittees and the public shall be the same uniform price as published by state law, if required under applicable law. Where a tax or markup is imposed in this section, the TABCC is authorized to impose the same tax or markup as a Tribal tax or markup, where appropriate, and to utilize such tax or markup in operations of TABCC and profits after operation shall be distributed as determined by the Executive Committee.

Secs. 18B–805—18B–899.—Reserved

Article 9—Issuance of Permits

Sec. 18B–900.—Nation's Gaming Enterprises Eligible for ABC Permit

The Nation's gaming enterprises shall be eligible to receive and to hold a Tribal ABC permit for the retail sale of alcoholic beverages on the premises of the Kings Mountain gaming facility and all additional gaming facilities authorized by the Commission. At the request of the Nation's gaming enterprises, TABCC is authorized to issue a permit to a contracted or leased facility providing a service for the Nation's gaming enterprises on the premises of Kings Mountain facilities.

Secs. 18B–901—18B–999.—Reserved

Article 10—Retail Activity

Secs. 18B–1000—18B–1003.—Reserved

Sec. 18B–1004.—Hours for Sale and Consumption

It shall be a violation of this Ordinance to sell alcoholic beverages on any licensed premises during hours when such sales are prohibited by either TABCC regulations or prevailing state law.

Sec. 18B–1005.—Conduct on Licensed Premises

(a) Certain conduct. It shall be a violation for a permittee or his agent or employee to knowingly allow any of the following kinds of conduct to occur on his licensed premises:

(1) Any violation of this Ordinance;

(2) Any unsanctioned fighting or other disorderly conduct that can be prevented without undue danger to the permittee, his employees or patrons; or

(3) Any violation of the controlled substances or prostitution statutes, or any other unlawful acts.

(b) Supervision. It shall be a violation for a permittee to fail to superintend in person or through a manager the business for which a permit is issued.

Sec. 18B–1006.—Reserved

Sec. 18B–1007.—Additional Requirements for Mixed Beverages Permittees

(a) Handling bottles. It shall be a violation for a mixed beverages permittee or the permittee's agent or employee to do any of the following:

(1) Store any other spirituous liquor with liquor possessed for resale in mixed beverages or from a guest room cabinet.

(2) Refill any spirituous liquor container having a mixed beverages tax stamp with any other alcoholic beverage or add to the contents of such a container any other alcoholic beverage.

(3) Transfer from one container to another a mixed beverages tax stamp.

(4) Possess any container of spirituous liquor not bearing a mixed beverages tax stamp, except for containers being brought onto the premises by the host of a private function under a special occasion permit.

(b) Price list. Each mixed beverages permittee shall have available for its customers the printed prices of the most common or popular mixed beverages offered for sale by the permittee.

Article 11—Amendments

Sec. 18B–1100.—Approval Process; Authority of the Executive Committee To Amend This Ordinance

In approving this Ordinance for the regulation of alcoholic beverages, the General Council hereby expressly authorizes the Executive Committee to amend as necessary the provisions of this Ordinance, without the need for further review or approval by the General Council, to address issues raised by the federal government in order to secure the Ordinance's approval and as necessary to obtain the applicable regulatory approvals, and such amendments shall be fully incorporated herein and shall be binding upon the Nation in accordance with their terms. If the Executive Committee exercises this authority to amend this Ordinance it shall thereafter inform the General Council of those amendments no later than the next meeting of the General Council.

Bryan Newland,

Assistant Secretary—Indian Affairs.

[FR Doc. 2021–24770 Filed 11–12–21; 8:45 am]

BILLING CODE 4337–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[LLCO956000 L14400000.BJ0000 22X]

Notice of Filing of Plats of Survey, Colorado

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of official filing.

SUMMARY: The plats of survey of the following described lands are scheduled to be officially filed in the Bureau of Land Management (BLM), Colorado State Office, Lakewood, Colorado, 30 calendar days from the date of this publication. The surveys, which were executed at the request of the U.S. Forest Service and the BLM, are necessary for the management of these lands.

DATES: Unless there are protests of this action, the plats described in this notice will be filed on December 15, 2021.

ADDRESSES: You may submit a written protest to the BLM Colorado State Office, Cadastral Survey, 2850 Youngfield Street, Lakewood, CO 80215–7210.

FOR FURTHER INFORMATION CONTACT: Janet Wilkins, Chief Cadastral Surveyor for Colorado, telephone: (303) 239–3818; email: *j1wilkin@blm.gov.* Persons who use a telecommunications device for the deaf may call the Federal Relay Service at 1–800–877–8339 to contact Ms. Wilkins during normal business hours. The Service is available 24 hours a day, 7 days a week, to leave a message or question. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION: The plat, in two sheets, incorporating the field notes of the dependent resurvey and subdivision of section 21 in Township 9 South, Range 70 West, Sixth Principal Meridian, Colorado, was accepted on September 10, 2021.

The plat incorporating the field notes of the survey in unsurveyed Townships 41 North, Ranges 7 and 8 West, New Mexico Principal Meridian, Colorado, was accepted on September 24, 2021.

The plat, in two sheets, incorporating the field notes of the corrective dependent resurvey and survey in partially surveyed Township 19 South, Range 73 West, Sixth Principal Meridian, Colorado, was accepted on September 30, 2021.

The plat, in two sheets, incorporating the field notes of the survey in Townships 42 North, Ranges 7 and 8 West, New Mexico Principal Meridian, Colorado, was accepted on September 30, 2021.

A person or party who wishes to protest any of the above surveys must file a written notice of protest within 30 calendar days from the date of this publication at the address listed in the **ADDRESSES** section of this notice. A statement of reasons for the protest may be filed with the notice of protest and must be filed within 30 calendar days after the protest is filed. If a protest of the survey is received prior to the date of official filing, the filing will be stayed pending consideration of the protest. A plat will not be officially filed until the day after all protests have been dismissed or otherwise resolved.

Before including your address, phone number, email address, or other personal identifying information in your protest, please be aware that your entire protest, including your personal identifying information, may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

(Authority: 43 U.S.C. Chap. 3)

Janet Wilkins,

Chief Cadastral Surveyor.

[FR Doc. 2021–24832 Filed 11–12–21; 8:45 am]

BILLING CODE 4310–JB–P

DEPARTMENT OF THE INTERIOR

Bureau of Reclamation

[RR83550000, 223R5065C6, RX.59389832.1009676]

Quarterly Status Report of Water Service, Repayment, and Other Water-Related Contract Actions

AGENCY: Bureau of Reclamation, Interior.

ACTION: Notice of contract actions.

SUMMARY: Notice is hereby given of contractual actions that have been proposed to the Bureau of Reclamation (Reclamation) and are new, discontinued, or completed since the last publication of this notice. This notice is one of a variety of means used to inform the public about proposed contractual actions for capital recovery and management of project resources and facilities consistent with section 9(f) of the Reclamation Project Act of 1939. Additional announcements of individual contract actions may be published in the **Federal Register** and in newspapers of general circulation in the areas determined by Reclamation to be affected by the proposed action.

ADDRESSES: The identity of the approving officer and other information pertaining to a specific contract proposal may be obtained by calling or writing the appropriate regional office at the address and telephone number given for each region in the **SUPPLEMENTARY INFORMATION** section of this notice.

FOR FURTHER INFORMATION CONTACT: Michelle Kelly, Reclamation Law Administration Division, Bureau of Reclamation, P.O. Box 25007, Denver, Colorado 80225–0007; *mkelly@usbr.gov;* telephone 303–445–2888.

SUPPLEMENTARY INFORMATION: Consistent with section 9(f) of the Reclamation Project Act of 1939, and the rules and regulations published in 52 FR 11954, April 13, 1987 (43 CFR 426.22), Reclamation will publish notice of proposed or amendatory contract actions for any contract for the delivery of project water for authorized uses in newspapers of general circulation in the affected area at least 60 days prior to contract execution. Announcements may be in the form of news releases, legal notices, official letters, memorandums, or other forms of written material. Meetings, workshops, and/or hearings may also be used, as appropriate, to provide local publicity. The public participation procedures do not apply to proposed contracts for the sale of surplus or interim irrigation water for a term of 1 year or less. Either

of the contracting parties may invite the public to observe contract proceedings. All public participation procedures will be coordinated with those involved in complying with the National Environmental Policy Act. Pursuant to the ''Final Revised Public Participation Procedures'' for water resource-related contract negotiations, published in 47 FR 7763, February 22, 1982, a tabulation is provided of all proposed contractual actions in each of the five Reclamation regions. When contract negotiations are completed, and prior to execution, each proposed contract form must be approved by the Secretary of the Interior, or pursuant to delegated or redelegated authority, the Commissioner of Reclamation or one of the regional directors. In some instances, congressional review and approval of a report, water rate, or other terms and conditions of the contract may be involved.

Public participation in and receipt of comments on contract proposals will be facilitated by adherence to the following procedures:

1. Only persons authorized to act on behalf of the contracting entities may negotiate the terms and conditions of a specific contract proposal.

2. Advance notice of meetings or hearings will be furnished to those parties that have made a timely written request for such notice to the appropriate regional or project office of Reclamation.

3. Written correspondence regarding proposed contracts may be made available to the general public pursuant to the terms and procedures of the Freedom of Information Act, as amended.

4. Written comments on a proposed contract or contract action must be submitted to the appropriate regional officials at the locations and within the time limits set forth in the advance public notices.

5. All written comments received and testimony presented at any public hearings will be reviewed and summarized by the appropriate regional office for use by the contract approving authority.

6. Copies of specific proposed contracts may be obtained from the appropriate regional director or his or her designated public contact as they become available for review and comment.

7. In the event modifications are made in the form of a proposed contract, the appropriate regional director shall determine whether republication of the notice and/or extension of the comment period is necessary.

Factors considered in making such a determination shall include, but are not limited to, (i) the significance of the modification, and (ii) the degree of public interest which has been expressed over the course of the negotiations. At a minimum, the regional director will furnish revised contracts to all parties who requested the contract in response to the initial public notice.

Definitions of Abbreviations Used in the Reports

ARRA American Recovery and Reinvestment Act of 2009
BCP Boulder Canyon Project
Reclamation Bureau of Reclamation
CAP Central Arizona Project
CUP Central Utah Project
CVP Central Valley Project
CRSP Colorado River Storage Project
XM Extraordinary maintenance
EXM Emergency Extraordinary Maintenance
FR Federal Register
IDD Irrigation and Drainage District
ID Irrigation District
M&I Municipal and Industrial
O&M Operation and Maintenance
OM&R Operation, Maintenance, and Replacement
P–SMBP Pick-Sloan Missouri Basin Program
RRA Reclamation Reform Act of 1982
SOD Safety of Dams
SRPA Small Reclamation Projects Act of 1956
USACE U.S. Army Corps of Engineers
WD Water District

Missouri Basin—Interior Region 5: Bureau of Reclamation, P.O. Box 36900, Federal Building, 2021 4th Avenue North, Billings, Montana 59101, telephone 406–247–7752.

Completed contract actions:

28. Gering-Fort Laramie ID, North Platte Project, Wyoming and Nebraska: Consideration of a repayment contract for XM and replacement funded pursuant to Title IX, Subtitle G of Public Law 111–11. Contract completed July 2, 2021.

38. Ptarmigan Partners, LLC, Shoshone Project, Wyoming: Consideration for renewal of water service contract No. 19E6A0227A. Contract completed August 27, 2021.

Upper Colorado Basin—Interior Region 7: Bureau of Reclamation, 125 South State Street, Room 8100, Salt Lake City, Utah 84138–1102, telephone 801–524–3864.

New contract actions:

30. Albuquerque Bernalillo County Water Utility Authority, San Juan-Chama Project, New Mexico: The Albuquerque Bernalillo County Water Utility Authority and Reclamation have entered negotiations for a contract to lease 10,000 acre-feet of storage space in Abiquiu Reservoir to store San Juan-Chama Project water. This will be a 15-year contract beginning 2022 through 2036. This contract will require a public forum for the negotiations process which will take place in October 2021.

31. Jicarilla Apache Nation, Navajo Project, New Mexico: Water service agreement between the Jicarilla Apache Nation and the San Juan Basin Water Haulers Association for delivery of 400 acre-feet of M&I water from the Jicarilla Apache Nation's settlement water from Navajo Reservoir. This agreement will have a term of 5 years.

32. Jicarilla Apache Nation, Navajo Project, New Mexico: Water service agreement between the Jicarilla Apache Nation and the Elks Lodge 1747 for delivery of 20 acre-feet of M&I water from the Jicarilla Apache Nation's settlement water from Navajo Reservoir. This agreement will have a term of 5 years.

Completed contract actions:

4. Strawberry High Line Canal Company, Strawberry Valley Project; Utah: The Strawberry High Line Canal Company has requested to allow for the carriage of non-project water held by McMullin Orchards in the High Line Canal. Contract completed on June 7, 2021.

14. Sanpete Water Conservancy District, Gooseberry Project, Utah: The District has requested Reclamation convey back its reversionary interest in a 1975 Water Right Assignment Contract with the District. Contract completed on June 17, 2021.

15. Uintah Water Conservancy District; Vernal Unit, CUP; Utah: The District has requested to amend carriage contract No. 15–WC–40–587 to include an M&I component into the 35,000 acre-feet ceiling. Contract completed on September 20, 2021.

16. Uintah Water Conservancy District; Vernal Unit, CUP; Utah: The District has requested to amend repayment contract No. 14–06–400–778 to convert the M&I water service provisions to repayment provisions. Contract completed on September 20, 2021.

Lower Colorado Basin—Interior Region 8: Bureau of Reclamation, P.O. Box 61470 (Nevada Highway and Park Street), Boulder City, Nevada 89006–1470, telephone 702–293–8192.

New contract actions:

20. Cibola Valley Irrigation and Drainage District (CVIDD) and The Cibola Sportsman's Club, Inc., Alfred F. and Emma Jean Bishop Family Trust, and Bruce and Lora Cathcart and James and Aria Cathcart (Beneficiaries) BCP, Arizona: Enter into a proposed partial

assignment and transfer of Arizona fourth-priority Colorado River water in the amount of 762 acre-feet per year from CVIDD to be divided amongst the Beneficiaries. Amend CVIDD's Colorado River water delivery contract No. 2–07–30–W0028 to decrease its Colorado River water entitlement from 8,204.52 to 7,442.52 acre-feet per year. Enter into Colorado River water delivery contracts for Arizona fourth-priority Colorado River water entitlements under contract No. 21–XX–30–W0717 with The Cibola Sportsman's Club, Inc. for 216 acre-feet per year, contract No. 21–XX–30–W0718 with Alfred F. and Erma Jean Bishop Family Trust for 420 acre-feet per year, and contract No. 21–XX–30–W0719 with Bruce and Lora Cathcart and James and Maria Cathcart for 126 acre-feet per year.

21. City of Needles, BCP, California: Approve a new point of diversion under contract No. 05–XX–30–W0445, as amended, dated March 16, 2007, and contract No. 2–07–30–W0280, as amended, dated July 3, 2002, and revise the necessary exhibits of the above-referenced contracts to add an additional point of diversion.

Columbia-Pacific Northwest—Interior Region 9: Bureau of Reclamation, 1150 North Curtis Road, Suite 100, Boise, Idaho 83706–1234, telephone 208–378–5344.

The Columbia-Pacific Northwest—Interior Region 9 has no updates to report for this quarter.

California-Great Basin—Interior Region 10: Bureau of Reclamation, 2800 Cottage Way, Sacramento, California 95825–1898, telephone 916–978–5250.

Discontinued contract action:

3. Contractors from the Delta Division, Cross Valley Canal, and West San Joaquin Division; CVP; California: Renewal of 10 interim and long-term water service contracts; water quantities for these contracts total in excess of 148,000 acre-feet. These contract actions will be accomplished through long-term renewal contracts pursuant to Public Law 102–575. Prior to completion of negotiation of long-term renewal contracts, existing interim renewal water service contracts may be renewed through successive interim renewal of contracts.

Completed contract actions:

40. Tehama-Colusa Canal Authority, CVP, California: Renewal of OM&R contract. Contract completed on September 28, 2021.

42. Shasta County Water Agency, CVP, California: Proposed partial assignment of 50 acre-feet of the Shasta County Water Agency's CVP water supply to the City of Shasta Lake for M&I use. Contract completed on August 9, 2021.

43. Friant Water Authority, CVP, California: Negotiation and execution of a repayment contract for Friant Kern Canal Middle Reach Capacity Correction Project. Contract completed on September 23, 2021.

Christopher Beardsley,

Director, Policy and Programs.

[FR Doc. 2021–24762 Filed 11–12–21; 8:45 am]

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DEPARTMENT OF JUSTICE

Drug Enforcement Administration

[Docket No. DEA–688F]

Final Adjusted Aggregate Production Quotas for Schedule I and II Controlled Substances and Assessment of Annual Needs for the List I Chemicals Ephedrine, Pseudoephedrine, and Phenylpropanolamine for 2021

AGENCY: Drug Enforcement Administration, Department of Justice.

ACTION: Final order.

SUMMARY: This final order establishes the final adjusted 2021 aggregate production quotas for controlled substances in schedules I and II of the Controlled Substances Act and the assessment of annual needs for the list I chemicals ephedrine, pseudoephedrine, and phenylpropanolamine.

DATES: This order is effective November 15, 2021.

FOR FURTHER INFORMATION CONTACT: Scott A. Brinks, Regulatory Drafting and Policy Support Section, Diversion Control Division, Drug Enforcement Administration; Mailing Address: 8701 Morrissette Drive, Springfield, VA 22152, Telephone: (571) 362–3261.

SUPPLEMENTARY INFORMATION:

Legal Authority

Section 306 of the Controlled Substances Act (CSA) (21 U.S.C. 826) requires the Attorney General to establish aggregate production quotas (APQ) for each basic class of controlled substances listed in schedules I and II and for the list I chemicals ephedrine, pseudoephedrine, and phenylpropanolamine. The Attorney General has delegated this function to the Administrator of the Drug Enforcement Administration (DEA) pursuant to 28 CFR 0.100.

Background

DEA published the 2021 established APQ for controlled substances in schedules I and II and for the assessment of annual needs (AAN) for the list I chemicals ephedrine, pseudoephedrine, and phenylpropanolamine in the **Federal Register** on November 30, 2020. 85 FR 76604. DEA is committed to preventing and limiting diversion by enforcing laws and regulations regarding controlled substances and the list I chemicals ephedrine, pseudoephedrine, and phenylpropanolamine, while meeting the legitimate medical, scientific, and export needs of the United States. This notice stated that the Administrator would adjust, as needed, the established APQ in 2021 in accordance with 21 CFR 1303.13 and 21 CFR 1315.13.

The 2021 proposed adjusted APQ for controlled substances in schedules I and II and AAN for the list I chemicals ephedrine, pseudoephedrine, and phenylpropanolamine were subsequently published in the **Federal Register** on September 2, 2021, (86 FR 49346), after consideration of the criteria outlined in that notice. All interested persons were invited to comment on or object to the proposed APQs and AANs on or before October 4, 2021.

Comments Received

DEA received 27 timely comments in response to the September **Federal Register** notice from patients, DEA-registered entities, and non-DEA entities. The comments included appreciation of DEA's response to the increased interest in research using hallucinogenic controlled substances, requests to increase the APQ for additional hallucinogenic controlled substances, requests to increase the APQ for select schedule II controlled substances, concerns regarding the inability to comment to the notice electronically for two weeks, and comments outside the scope of this final order.

Issue: Commenters expressed appreciation of DEA's flexibility in responding to the nationwide public interest in hallucinogenic controlled substances research.

DEA Response: DEA acknowledges the expressions of appreciation to changes in the APQ for these controlled substances. The adjustments to select hallucinogenic schedule I controlled substances occurred after DEA received additional schedule I researcher protocols from DEA registered researchers and quota applications from DEA registered manufacturers.

Issue: Commenters requested DEA to increase the APQ for Bufotenine, Dimethyltryptamine (DMT), N,N-Dimethyltryptamine, 5-Methoxy-N,N-

dimethyltryptamine (5MEODMT), Ibogaine, Ketamine, Lysergic Acid Diethylamide (LSD), 3,4-Methylenedioxymethamphetamine (MDMA), Mescaline, Mitragynine, and Psilocybin in response to the nationwide public interest in hallucinogenic controlled substances research.

DEA Response: Ketamine is a schedule III controlled substance and therefore is outside of the scope of this final order as DEA only sets APQs for substances controlled in schedules I and II. DEA received additional quota applications for DMT, MDMA, and Psilocybin and considered the timely provided information in those applications for this final order. Regarding the other controlled substances listed, DEA has not received quota applications from DEA-registered manufacturers to support the requested changes in the APQ for these controlled substances. Mitragynine is not a controlled substance and therefore is outside the scope of this final order.

Issue: DEA-registered entities requested that the APQ for Methadone, Methadone Intermediate, Methylphenidate Oxycodone (for sale), Phenylacetone, and Thebaine be sufficient to provide for the estimated medical, scientific, research, and industrial needs of the United States, for export requirements, and for the establishment and maintenance of reserve stocks.

DEA Response: DEA sets APQ in a manner to ensure that the estimated medical, scientific, research, industrial needs of the United States, lawful export requirements, and for the establishment and maintenance of reserve stocks. As discussed in the notice for adjustment, any adjustments to the APQ for a controlled substance are based on factors set forth in 21 CFR 1303.13. In the event of a shortage, the CSA provides a mechanism under which DEA will, in appropriate circumstances, increase quotas to address shortages. 21 U.S.C. 826(h). Under 21 U.S.C. 826(h)(1), after receiving a request to address a shortage, DEA has 30 days to complete review of the request and determine whether adjustments are necessary to address the shortage. If adjustments are necessary, DEA is required to increase the APQ and individual production quotas to alleviate the shortage. *Id.* If DEA determines adjustments are not necessary, DEA is required to ''provide a written response detailing the basis for the . . . determination.'' *Id.* In addition to what Section 826(h)(1) requires, when DEA is notified of an alleged shortage, DEA will confer with the Food and Drug Administration and relevant manufacturers regarding the amount of material in physical inventory, current quota granted, and the estimated legitimate medical need, to determine whether a quota adjustment is necessary to alleviate any quota-related drug shortage.

In accordance with 21 CFR 1303.13, DEA considered the comments for Bufotenine, 5-Methoxy-N,N-dimethyltryptamine (5MEODMT), Ibogaine, Lysergic Acid Diethylamide (LSD), Mescaline, Methadone, Methadone Intermediate, Oxycodone (for sale), and Thebaine and the Administrator determined the proposed adjusted 2021 APQs for these substances as published in the **Federal Register** on September 2, 2021, (86 FR 49346), are sufficient to meet the current 2021 estimated medical, scientific, research, and industrial needs of the United States, lawful export requirements, and to provide for adequate reserve stock.

Issue: Commenters expressed general concerns regarding the inability to submit electronic comments to the notice published on September 2, 2021, for two weeks. Commenters requested an extension of the comment period to allow for additional comments.

DEA Response: DEA acknowledges that commenters could not submit electronic comments to the notice for two weeks. However, written comments could be submitted via mail to the address provided in the notice. Written comments that were postmarked on or before October 4, 2021, were considered in this final order. DEA notes that one commenter submitted identical electronic and written comments both of which were timely postmarked, received, and considered for this final order.

Out of Scope Comments: DEA received comments on issues outside the scope of this final order. Commenters made several suggestions to the DEA, including: (1) Seeking assistance from indigenous communities to determine the amount of psychedelic substances that would be needed to conduct research; (2) making the United States a signatory to the *Nagoya Protocol and the Convention on Biological Diversity;* and (3) creating diversified categories for production and research on psilocybin-containing fungi fruiting bodies/sclerotia/liquid culture similar to cannabis (flower), fruiting body extract (akin to cannabis extract), and psilocybin and psilocin separately as purified compounds (akin to delta-9-thc). Regarding this last suggestion, the commenter further suggested that the ''same system should then be replicated in regards to lophophora/mescaline, as well as other plants, fungi and lifeforms, which produce these compounds being used in whole or closer to whole ways.''

DEA received other comments that were general in nature and raised issues of specific medical illnesses and medical treatments. All of the issues raised are outside of the scope of this final order for 2021 and do not impact the original analysis involved in finalizing the 2021 APQ.

Analysis for Final Adjusted 2021 Aggregate Production Quotas and Assessment of Annual Needs

In determining the final adjusted 2021 APQ and AAN, DEA considered the above comments relevant to this final order for calendar year 2021, along with the factors set forth in 21 CFR 1303.13 and 21 CFR 1315.13, in accordance with 21 U.S.C. 826(a). DEA has also considered other relevant factors, including the 2020 year-end inventories, initial 2021 manufacturing and import quotas, 2021 export requirements, actual and projected 2021 sales, research and product development requirements, additional applications received, and the extent of any diversion of the controlled substance in the class. Based on all of the above, the Administrator is adjusting the 2021 APQ for the following: 3,4-Methylenedioxymethamphetamine (MDMA), 4,4′-Dimethylaminorex, Dimethyltryptamine (DMT), Lisdexamfetamine, Methiopropamine, Psilocybin, Psilocyn, and Phenylacetone. This final order reflects those adjustments.

Pursuant to the above, the Administrator hereby finalizes the 2021 APQ for the following schedule I and II controlled substances and the 2021 AAN for the list I chemicals ephedrine, pseudoephedrine, and phenylpropanolamine, expressed in grams of anhydrous acid or base, as follows:

Basic class	Final adjusted 2021 quotas (g)
Schedule I	
1-[1-(2-Thienyl)cyclohexyl]pyrrolidine	20
1-(1-Phenylcyclohexyl)pyrrolidine	30
1-(2-Phenylethyl)-4-phenyl-4-acetoxypiperidine	10
1-(5-Fluoropentyl)-3-(1-naphthoyl)indole (AM2201)	30
1-(5-Fluoropentyl)-3-(2-iodobenzoyl)indole (AM694)	30
1-Benzylpiperazine	25
1-Methyl-4-phenyl-4-propionoxypiperidine	10
1-[1-(2-Thienyl)cyclohexyl]piperidine	15
2'-fluoro 2-fluorofentanyl	30
2-(2,5-Dimethoxy-4-ethylphenyl)ethanamine (2C–E)	30
2-(2,5-Dimethoxy-4-methylphenyl)ethanamine (2C–D)	30
2-(2,5-Dimethoxy-4-nitro-phenyl)ethanamine (2C–N)	30
2-(2,5-Dimethoxy-4-n-propylphenyl)ethanamine (2C–P)	30
2-(2,5-Dimethoxyphenyl)ethanamine (2C–H)	100
2-(4-Bromo-2,5-dimethoxyphenyl)-N-(2-methoxybenzyl)ethanamine (25B–NBOMe; 2C–B–NBOMe; 25B; Cimbi-36)	30
2-(4-Chloro-2,5-dimethoxyphenyl)ethanamine (2C–C)	30
2-(4-Chloro-2,5-dimethoxyphenyl)-N-(2-methoxybenzyl)ethanamine (25C–NBOMe; 2C–C–NBOMe; 25C; Cimbi-82)	25
2-(4-Iodo-2,5-dimethoxyphenyl)ethanamine (2C–I)	30
2-(4-Iodo-2,5-dimethoxyphenyl)-N-(2-methoxybenzyl)ethanamine (25I–NBOMe; 2C–I–NBOMe; 25I; Cimbi-5)	30
2,5-Dimethoxy-4-ethylamphetamine (DOET)	25
2,5-Dimethoxy-4-n-propylthiophenethylamine	25
2,5-Dimethoxyamphetamine (DMA)	25
2-[4-(Ethylthio)-2,5-dimethoxyphenyl]ethanamine (2C–T–2)	30
2-[4-(Isopropylthio)-2,5-dimethoxyphenyl]ethanamine (2C–T–4)	30
3,4,5-Trimethoxyamphetamine	30
3,4-Methylenedioxyamphetamine (MDA)	55
3,4-Methylenedioxymethamphetamine (MDMA)	3,200
3,4-Methylenedioxy-N-ethylamphetamine (MDEA)	40
3,4-Methylenedioxy-N-methylcathinone (methylone)	40
3,4-Methylenedioxypyrovalerone (MDPV)	35
3–FMC; 3-Fluoro-N-methylcathinone	25
3-Methylfentanyl	30
3-Methylthiofentanyl	30
4′-Methyl acetyl fentanyl	30
4,4'-Dimethylaminorex	30
4-Bromo-2,5-dimethoxyamphetamine (DOB)	30
4-Bromo-2,5-dimethoxyphenethylamine (2–CB)	25
4-Chloro-α-pyrrolidinovalerophenone (4-chloro-alpha-PVP)	25
4CN-Cumyl-Butanica, 1-(4-Cyanobutyl)-N-(2-phenylpropan-2-yl)-1H-indazole-3-carboximide	25
4F–MDMB–BINACA	30
4-Fluoroisobutyryl fentanyl	30
4–FMC; Flephedrone	25
4–MEC; 4-Methyl-N-ethylcathinone	25
4-Methoxyamphetamine	150
4-Methyl-2,5-dimethoxyamphetamine (DOM)	25
4-Methylaminorex	25
4-Methyl-N-methylcathinone (mephedrone)	45
4-Methyl-α-ethylaminopentiophenone (4–MEAP)	25
4-Methyl-α-pyrrolidinohexiophenone (MPHP)	25
4-Methyl-α-pyrrolidinopropiophenone (4-MePPP)	25
5-(1,1-Dimethylheptyl)-2-[(1R,3S)-3-hydroxycyclohexyl]-phenol	50
5-(1,1-Dimethyloctyl)-2-[(1R,3S)-3-hydroxycyclohexyl]-phenol (cannabicyclohexanol or CP–47,497 C8-homolog)	40
5F–CUMYL–PINACA	25
5F–EDMB–PINACA	25
5F–MDMB–PICA	25
5F–AB–PINACA; N-(1-amino-3-methyl-1-oxobutan-2-yl)-1-(5-fluoropentyl)-1H-indazole-3-carboxamide	25
5F–CUMYL–P7AICA; (1-(5-fluoropentyl)-N-(2-phenylpropan-2-yl)-1H-pyrrolo[2,3-b]pyridine-3-carboximide)	25
5F–ADB; 5F–MDMB–PINACA (methyl 2-(1-(5-fluoropentyl)-1H-indazole-3-carboxamido)-3,3-dimethylbutanoate)	30
5F–AMB (methyl 2-(1-(5-fluoropentyl)-1*H*-indazole-3-carboxamido)-3-methylbutanoate)	30
5F–APINACA; 5F–AKB48 (*N*-(adamantan-1-yl)-1-(5-fluoropentyl)-1*H*-indazole-3-carboxamide)	30
5-Fluoro-PB–22; 5F–PB–22	20
5-Fluoro-UR144, XLR11 ([1-(5-fluoro-pentyl)-1*H*-indol-	
3-yl](2,2,3,3-tetramethylcyclopropyl)methanone	25
5-Methoxy-3,4-methylenedioxyamphetamine	25
5-Methoxy-N,N-diisopropyltryptamine	25
5-Methoxy-N,N-dimethyltryptamine	35
AB–CHMINACA	30
AB–FUBINACA	50

Basic class	Final adjusted 2021 quotas (g)
AB–PINACA	30
ADB–FUBINACA (*N*-(1-amino-3,3-dimethyl-1-oxobutan-2-yl)-1-(4-fluorobenzyl)-1*H*-indazole-3-carboxamide)	30
Acetorphine	25
Acetyl Fentanyl	100
Acetyl-*alpha*-methylfentanyl	30
Acetyldihydrocodeine	30
Acetylmethadol	25
Acryl Fentanyl	25
ADB–PINACA (*N*-(1-amino-3,3-dimethyl-1-oxobutan-2-yl)-1-pentyl-1*H*-indazole-3-carboxamide)	50
AH–7921	30
All other tetrahydrocannabinol	1,000
Allylprodine	25
Alphacetylmethadol	25
alpha-Ethyltryptamine	25
Alphameprodine	25
Alphamethadol	25
Alphaprodine	25
alpha-Methylfentanyl	30
alpha-Methylthiofentanyl	30
alpha-Methyltryptamine (AMT)	25
alpha-Pyrrolidinobutiophenone (α-PBP)	25
alpha-Pyrrolidinoheptaphenone (PV8)	25
alpha-Pyrrolidinohexanophenone (α-PHP)	25
alpha-Pyrrolidinopentiophenone (α-PVP)	25
Aminorex	25
Anileridine	20
APINCA, AKB48 (*N*-(1-adamantyl)-1-pentyl-1*H*-indazole-3-carboxamide)	25
Benzethidine	25
Benzylmorphine	30
Betacetylmethadol	25
beta-Hydroxy-3-methylfentanyl	30
beta-Hydroxyfentanyl	30
beta-Hydroxythiofentanyl	30
beta-Methyl fentanyl	30
beta-Phenyl fentanyl	30
Betameprodine	25
Betamethadol	4
Betaprodine	25
Brorphine	30
Bufotenine	15
Butylone	25
Butyryl fentanyl	30
Cathinone	40
Clonitazene	25
Codeine methylbromide	30
Codeine-N-oxide	192
Cyclopentyl Fentanyl	30
Cyclopropyl Fentanyl	20
Cyprenorphine	25
d-9–THC	384,460
Desomorphine	25
Dextromoramide	25
Diapromide	20
Diethylthiambutene	20
Diethyltryptamine	25
Difenoxin	9,200
Dihydromorphine	753,500
Dimenoxadol	25
Dimepheptanol	25
Dimethylthiambutene	20
Dimethyltryptamine	3,200
Dioxyaphetyl butyrate	25
Dipipanone	25
Drotebanol	25
Ethylmethylthiambutene	25
Etorphine	30
Etoxeridine	25
Fenethylline	30
Fentanyl carbamate	30
Fentanyl related substances	600

Basic class	Final adjusted 2021 quotas (g)
FUB–144	25
FUB–AKB48	25
FUB–AMB, MMB-Fubinaca, AMB-Fubinaca	25
Furanyl fentanyl	30
Furethidine	25
gamma-Hydroxybutyric acid	29,417,000
Heroin	45
Hydromorphinol	40
Hydroxypethidine	25
Ibogaine	30
Isobutyryl Fentanyl	25
JWH–018 and AM678 (1-Pentyl-3-(1-naphthoyl)indole)	35
JWH–019 (1-Hexyl-3-(1-naphthoyl)indole)	45
JWH–073 (1-Butyl-3-(1-naphthoyl)indole)	45
JWH–081 (1-Pentyl-3-[1-(4-methoxynaphthoyl)]indole)	30
JWH–122 (1-Pentyl-3-(4-methyl-1-naphthoyl)indole)	30
JWH–200 (1-[2-(4-Morpholinyl)ethyl]-3-(1-naphthoyl)indole)	35
JWH–203 (1-Pentyl-3-(2-chlorophenylacetyl)indole)	30
JWH–250 (1-Pentyl-3-(2-methoxyphenylacetyl)indole)	30
JWH–398 (1-Pentyl-3-(4-chloro-1-naphthoyl)indole)	30
Ketobemidone	30
Levomoramide	25
Levophenacylmorphan	25
Lysergic acid diethylamide (LSD)	40
MAB–CHMINACA; ADB–CHMINACA (*N*-(1-amino-3,3-dimethyl-1-oxobutan-2-yl)-1-(cyclohexylmethyl)-1*H*-indazole-3-carboxamide)	30
MDMB–CHMICA; MMB–CHMINACA(methyl 2-(1-(cyclohexylmethyl)-1*H*-indole-3-carboxamido)-3,3-dimethylbutanoate)	30
MDMB–FUBINACA (methyl 2-(1-(4-fluorobenzyl)-1*H*-indazole-3-carboxamido)-3,3-dimethylbutanoate)	30
MMB–CHMICA-(AMB–CHMICA); Methyl-2-(1-(cyclohexylmethyl)-1H-indole-3-carboxamido)-3-methylbutanoate	25
Marihuana	2,000,000
Marihuana extract	500,000
Mecloqualone	30
Mescaline	25
Methaqualone	60
Methcathinone	25
Methiopropamine	30
Methyoxyacetyl fentanyl	30
Methyldesorphine	5
Methyldihydromorphine	25
Morpheridine	25
Morphine methylbromide	5
Morphine methylsulfonate	5
Morphine-N-oxide	150
MT–45	30
Myrophine	25
NM2201; Naphthalen-1-yl 1-(5-fluoropentyl)-1H-indole-3-carboxylate	25
N,N-Dimethylamphetamine	25
Naphyrone	25
N-Ethyl-1-phenylcyclohexylamine	25
N-Ethyl-3-piperidyl benzilate	10
N-Ethylamphetamine	24
N-Ethylhexedrone	25
N-Ethylpentylone, ephylone	30
N-Hydroxy-3,4-methylenedioxyamphetamine	24
N-Methyl-3-Piperidyl Benzilate	30
Nicocodeine	25
Nicomorphine	25
Noracymethadol	25
Norlevorphanol	2,550
Normethadone	25
Normorphine	40
Norpipanone	25
Ocfentanil	25
Ortho-fluorofentanyl, 2-fluorofentanyl	30
ortho-Fluoroacryl fentanyl	30
ortho-Fluorobutyryl fentanyl	30
ortho-Fluoroisobutyryl fentanyl	30
ortho-Methyl acetylfentanyl	30
ortho-Methyl methoxyacetyl fentanyl	30
Para-chloroisobutyryl fentanyl	30

Basic class	Final adjusted 2021 quotas (g)
Para-fluorofentanyl	25
Para-fluorobutyryl fentanyl	25
para-Fluoro furanyl fentanyl	30
para-Methylfentanyl	30
Para-methoxybutyryl fentanyl	30
Parahexyl	5
PB–22; QUPIC	20
Pentedrone	25
Pentylone	25
Phenadoxone	25
Phenampromide	25
Phenomorphan	25
Phenoperidine	25
Phenyl fentanyl	30
Pholcodine	5
Piritramide	25
Proheptazine	25
Properidine	25
Propiram	25
Psilocybin	6,000
Psilocyn	3,500
Racemoramide	25
SR–18 and RCS–8 (1-Cyclohexylethyl-3-(2-methoxyphenylacetyl)indole)	45
SR–19 and RCS–4 (1-Pentyl-3-[(4-methoxy)-benzoyl]indole)	30
Tetrahydrofuranyl fentanyl	15
Thebacon	25
Thiafentanil	25
Thiofentanyl	25
Thiofuranyl fentanyl	30
THJ–2201 ([1-(5-fluoropentyl)-1H-indazol-3-yl](naphthalen-1-yl)methanone)	30
Tilidine	25
Trimeperidine	25
UR–144 (1-pentyl-1H-indol-3-yl)(2,2,3,3-tetramethylcyclopropyl)methanone	25
U–47700	30
Valeryl fentanyl	25
Schedule II	
1-Phenylcyclohexylamine	15
1-Piperidinocyclohexanecarbonitrile	25
4-Anilino-N-phenethyl-4-piperidine (ANPP)	937,758
Alfentanil	3,260
Alphaprodine	25
Amobarbital	20,100
Bezitramide	25
Carfentanil	20
Cocaine	68,576
Codeine (for conversion)	1,612,500
Codeine (for sale)	27,616,684
D-amphetamine (for sale)	21,200,000
D,l-amphetamine	21,200,000
D-amphetamine (for conversion)	16,068,789
Dextropropoxyphene	35
Dihydrocodeine	156,713
Dihydroetorphine	25
Diphenoxylate (for conversion)	14,100
Diphenoxylate (for sale)	770,800
Ecgonine	68,576
Ethylmorphine	30
Etorphine hydrochloride	32
Fentanyl	731,452
Glutethimide	25
Hydrocodone (for conversion)	1,250
Hydrocodone (for sale)	30,821,224
Hydromorphone	2,743,101
Isomethadone	30
L-amphetamine	30
Levo-alphacetylmethadol (LAAM)	25
Levomethorphan	30
Levorphanol	26,495
Lisdexamfetamine	22,500,000

Basic class	Final adjusted 2021 quotas (g)
L-methamphetamine	587,229
Meperidine	856,695
Meperidine Intermediate-A	30
Meperidine Intermediate-B	30
Meperidine Intermediate-C	30
Metazocine	15
Methadone (for sale)	25,619,700
Methadone Intermediate	27,673,600
Methamphetamine	50
D-methamphetamine (for conversion)	485,020
D-methamphetamine (for sale)	40,000
Methylphenidate (for conversion)	15,300,000
Methylphenidate (for sale)	57,438,334
Metopon	25
Moramide-intermediate	25
Morphine (for conversion)	3,376,696
Morphine (for sale)	26,505,995
Nabilone	62,000
Norfentanyl	25
Noroxymorphone (for conversion)	22,044,741
Noroxymorphone (for sale)	376,000
Oliceridine	22,500
Opium (powder)	250,000
Opium (tincture)	530,837
Oripavine	33,010,750
Oxycodone (for conversion)	620,887
Oxycodone (for sale)	57,110,032
Oxymorphone (for conversion)	28,204,371
Oxymorphone (for sale)	563,174
Pentobarbital	30,766,670
Phenazocine	25
Phencyclidine	35
Phenmetrazine	25
Phenylacetone	6,100,000
Piminodine	25
Racemethorphan	5
Racemorphan	5
Remifentanil	3,000
Secobarbital	172,100
Sufentanil	4,000
Tapentadol	13,447,541
Thebaine	57,137,944
List I Chemicals	
Ephedrine (for conversion)	100
Ephedrine (for sale)	4,136,000
Phenylpropanolamine (for conversion)	14,878,320
Phenylpropanolamine (for sale)	16,690,000
Pseudoephedrine (for conversion)	1,000
Pseudoephedrine (for sale)	174,246,000

The Administrator further proposes that APQ for all other schedule I and II controlled substances included in 21 CFR 1308.11 and 1308.12 remain at zero.

Anne Milgram,

Administrator.

[FR Doc. 2021–24921 Filed 11–10–21; 4:15 pm]

BILLING CODE 4410–09–P

DEPARTMENT OF JUSTICE

[OMB Number 1117–0034]

Agency Information Collection Activities; Proposed eCollection, eComments Requested; Revision of a Currently Approved Collection; The National Forensic Laboratory Information System Collection of Analysis Data

AGENCY: Drug Enforcement Administration, Department of Justice.

ACTION: 30-Day Notice.

SUMMARY: The Department of Justice (DOJ), Drug Enforcement Administration (DEA), will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. This proposed information collection was previously published in the **Federal Register** at 86 FR 47523 on August 25, 2021, allowing for a 60 day comment period. No comments were received.

DATES: Comments are encouraged and will be accepted for an additional 30 days until December 15, 2021.

FOR FURTHER INFORMATION CONTACT: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

SUPPLEMENTARY INFORMATION:

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

—Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

—Evaluate whether and if so how the quality, utility, and clarity of the information proposed to be collected can be enhanced; and

—Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Overview of This Information Collection

1. *Type of Information Collection:* Revision of a currently approved collection.

2. *Title of the Form/Collection:* The National Forensic Laboratory Information System Collection of Analysis Data.

3. *The agency form number, if any, and the applicable component of the Department sponsoring the collection:* There are no form numbers associated with this collection. The applicable component within the Department of Justice is the Drug Enforcement Administration, Diversion Control Division.

4. *Affected public who will be asked or required to respond, as well as a brief abstract:*

Affected public (Primary): Forensic Science Laboratory Management.

Affected public (Other): None.

Abstract: This collection provides the Drug Enforcement Administration (DEA) with a national database on analyzed drug evidence from non-federal laboratories. Information from this database is combined with the other existing databases to develop more accurate, up-to-date information on abused drugs. This database represents a voluntary, cooperative effort on the part of participating laboratories to provide a centralized source of analyzed drug data.

5. *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* DEA estimates that 2,640 persons annually for this collection at 2.2015 hour per respondent, for an annual burden of 5,812 hours.

6. *An estimate of the total public burden (in hours) associated with the proposed collection:* DEA estimates that this collection takes 5,812 annual burden hours.

If additional information is required please contact: Melody Braswell, Department Clearance Officer, United States Department of Justice, Justice Management Division, Policy and Planning Staff, Two Constitution Square, 145 N Street NE, Suite 3E.405B, Washington, DC 20530.

Dated: November 8, 2021.

Melody Braswell,

Department Clearance Officer for PRA, U.S. Department of Justice.

[FR Doc. 2021–24780 Filed 11–12–21; 8:45 am]

BILLING CODE 4410–09–P

DEPARTMENT OF LABOR

Employment and Training Administration

Federal-State Unemployment Compensation Program: Certifications for 2021 Under the Federal Unemployment Tax Act

AGENCY: Employment and Training Administration, Department of Labor.

ACTION: Notice.

SUMMARY: The Secretary of Labor signed the annual certifications under the Federal Unemployment Tax Act, 26 U.S.C. 3301 *et seq.,* thereby enabling employers who make contributions to state unemployment funds to obtain certain credits against their liability for the federal unemployment tax. By letter, the certifications were transmitted to the Secretary of the Treasury. The letter and certifications are printed below.

Signed in Washington, DC, October 31, 2021.

Angela Hanks,

Acting Assistant Secretary, Employment and Training.

The Honorable Janet L. Yellen
Secretary of the Treasury
Department of the Treasury
1500 Pennsylvania Avenue NW
Washington, DC 20220

Dear Secretary Yellen:

Enclosed are an original and a copy of each of two separate certifications regarding state unemployment compensation laws pursuant to the Federal Unemployment Tax Act, for the 12-month period ending on October 31, 2021. One certification is with respect to the ''normal'' federal unemployment tax credit under Section 3304 of the Internal Revenue Code of 1986 (IRC), and the other certification is with respect to the ''additional'' tax credit under Section 3303 of the IRC. Both certifications list all 53 states.

Sincerely,

MARTIN J. WALSH

CERTIFICATION OF STATES TO THE SECRETARY OF THE TREASURY PURSUANT TO SECTION 3304(c) OF THE INTERNAL REVENUE CODE OF 1986

In accordance with the provisions of Section 3304(c) of the Internal Revenue Code of 1986 (26 U.S.C. 3304(c)), I hereby certify the following named states to the Secretary of the Treasury for the 12-month period ending on October 31, 2021, in regard to the unemployment compensation laws of those states, which heretofore have been approved under the Federal Unemployment Tax Act:

Alabama
Alaska
Arizona
Arkansas
California
Colorado
Connecticut
Delaware
District of Columbia
Florida
Georgia
Hawaii
Idaho
Illinois
Indiana
Iowa
Kansas
Kentucky
Louisiana
Maine
Maryland
Massachusetts
Michigan

Minnesota
Mississippi
Missouri
Montana
Nebraska
Nevada
New Hampshire
New Jersey
New Mexico
New York
North Carolina
North Dakota
Ohio
Oklahoma
Oregon
Pennsylvania
Puerto Rico
Rhode Island
South Carolina
South Dakota
Tennessee
Texas
Utah
Vermont
Virginia
Virgin Islands
Washington
West Virginia
Wisconsin
Wyoming

This certification is for the maximum credit allowable under Section 3302(a) of the Code.

Signed at Washington, DC, on October 31, 2021.

MARTIN J. WALSH

CERTIFICATION OF STATE UNEMPLOYMENT COMPENSATION LAWS TO THE SECRETARY OF THE TREASURY PURSUANT TO SECTION 3303(b)(1) OF THE INTERNAL REVENUE CODE OF 1986

In accordance with the provisions of paragraph (1) of Section 3303(b) of the Internal Revenue Code of 1986 (26 U.S.C. 3303(b)(1)), I hereby certify the unemployment compensation laws of the following named states, which heretofore have been certified pursuant to paragraph (3) of Section 3303(b) of the Code, to the Secretary of the Treasury for the 12-month period ending on October 31, 2021:

Alabama
Alaska
Arizona
Arkansas
California
Colorado
Connecticut
Delaware
District of Columbia
Florida
Georgia
Hawaii
Idaho
Illinois
Indiana
Iowa
Kansas
Kentucky
Louisiana
Maine
Maryland
Massachusetts
Michigan
Minnesota
Mississippi
Missouri
Montana
Nebraska
Nevada
New Hampshire
New Jersey
New Mexico
New York
North Carolina
North Dakota
Ohio
Oklahoma
Oregon
Pennsylvania
Puerto Rico
Rhode Island
South Carolina
South Dakota
Tennessee
Texas
Utah
Vermont
Virginia
Virgin Islands
Washington
West Virginia
Wisconsin
Wyoming

This certification is for the maximum additional credit allowable under Section 3302(b), subject to the limitations of Section 3302(c) of the Code.

Signed at Washington, DC, on October 31, 2021.

MARTIN J. WALSH

[FR Doc. 2021–24833 Filed 11–12–21; 8:45 am]

BILLING CODE 4510–30–P

DEPARTMENT OF LABOR

Employment and Training Administration

Agency Information Collection Activities; Comment Request; H–2A Sheepherder Recordkeeping Requirement

AGENCY: Employment and Training Administration, Labor.

ACTION: Notice.

SUMMARY: The Department of Labor's (DOL or Department) Employment and Training Administration (ETA) is soliciting comments concerning a proposed extension for the authority to conduct the information collection request (ICR), titled ''H–2A Sheepherder Recordkeeping Requirement.'' This action seeks an extension of the information collection without changes. This comment request is part of continuing Departmental efforts to reduce paperwork and respondent burden in accordance with the Paperwork Reduction Act of 1995 (PRA).

DATES: Consideration will be given to all written comments received by January 14, 2022.

ADDRESSES: A copy of this ICR with applicable supporting documentation, including a description of the likely respondents, proposed frequency of response, and estimated total burden, may be obtained for free by contacting Brian Pasternak, Administrator, Office of Foreign Labor Certification, by telephone at 202–693–8200 (this is not a toll-free number), TTY 1–877–889–5627 (this is not a toll-free number), or by email at *ETA.OFLC.Forms@dol.gov.*

Submit written comments about, or requests for a copy of, this ICR by email at *ETA.OFLC.Forms@dol.gov.*

FOR FURTHER INFORMATION CONTACT: Brian Pasternak, Administrator, Office of Foreign Labor Certification, by telephone at 202–693–8200 (this is not a toll-free number) or by email at *ETA.OFLC.Forms@dol.gov.*

Authority: 44 U.S.C. 3506(c)(2)(A).

SUPPLEMENTARY INFORMATION: DOL, in its continuing efforts to reduce paperwork and respondent burden, conducts a pre-clearance consultation program to provide the general public and Federal agencies an opportunity to comment on proposed and/or continuing collections of information before submitting them to the Office of Management and Budget (OMB) for final approval. This program ensures the public provides all necessary data in the desired format, the reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements can be properly assessed.

Under the foreign labor certification programs administered by ETA, the H–2A temporary labor certification program enables employers to bring nonimmigrant foreign workers to the U.S. to perform agricultural work of a temporary or seasonal nature, as defined in 8 U.S.C. 1101(a)(15)(H)(ii)(a). The H–2A program also permits employers to employ foreign workers in herding or the production of livestock on the range.

In order to meet its statutory responsibilities under the Immigration

and Nationality Act, the Department must request information from employers seeking to hire and import foreign labor. The Department uses the information collected to determine whether employers engaged in herding or production of livestock on the range, including the care, husbandry, and herding of sheep, cattle, goats, horses, and other domestic hooved animals, have met their obligations under Federal law. *See* 20 CFR 655.200, *et seq.* This ICR pertains to program obligations for employers seeking to hire foreign temporary agricultural workers for job opportunities in herding or production of livestock on the range. Among the issues addressed through this ICR are timekeeping requirements of employers. *See* 20 CFR 655.210(f). In order to determine eligibility for the program based on the daily amount of work performed on the range, this ICR requires employers to note whether employees spend days on the ranch or on the range. This ICR also requires employers to record the reason for the worker's absence where the employer chooses to prorate the required wage. *See* 20 CFR 655.210(f)(2), (g)(2). The information retained and recorded will enable the employer and the Department, if necessary, to determine whether the worker performed work on the range at least fifty percent of the days during the contract period.

This information collection is subject to the PRA. A Federal agency generally cannot conduct or sponsor a collection of information, and the public is generally not required to respond to an information collection unless OMB, under the PRA, approves it and the collection tool displays a currently valid OMB Control Number. In addition, notwithstanding any other provisions of law, no person shall generally be subject to penalty for failing to comply with a collection of information that does not display a valid Control Number. *See* 5 CFR 1320.5(a) and 1320.6.

Interested parties are encouraged to provide comments to the contact shown in the **ADDRESSES** section. Comments must be written to receive consideration, and they will be summarized and included in the request for OMB approval of the final ICR. In order to help ensure appropriate consideration, comments should mention OMB control number 1205–0519.

Submitted comments will also be a matter of public record for this ICR and posted on the internet, without redaction. DOL encourages commenters not to include personally identifiable information, confidential business data, or other sensitive statements/information in any comments.

DOL is particularly interested in comments that:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Agency: DOL–ETA.

Action: Extension Without Changes.

Title of Collection: H–2A Sheepherder Recordkeeping Requirement.

OMB Control Number: 1205–0519.

Affected Public: Private Sector.

Form(s): None.

Total Estimated Number of Annual Respondents: 968.

Frequency: Weekly (52 weeks).

Total Estimated Annual Responses: 50,336.

Average Time per Response: 6 minutes.

Total Estimated Annual Time Burden: 5,034.

Total Estimated Annual Other Costs Burden: $0.

Authority: 44 U.S.C. 3507(a)(1)(D).

Angela Hanks,

Acting Assistant Secretary for Employment and Training, Labor.

[FR Doc. 2021–24812 Filed 11–12–21; 8:45 am]

BILLING CODE 4510–FP–P

DEPARTMENT OF LABOR

Employment and Training Administration

Update to Appendix A to the Preamble—Education and Training Categories by O*NET—SOC Occupations; Labor Certification for Permanent Employment of Immigrants in the United States and Procedures To Establish Job Zone Values When O*NET Job Zone Data Are Unavailable

AGENCY: Employment and Training Administration, Department of Labor.

ACTION: Notice.

SUMMARY: The Employment and Training Administration (ETA) of the Department of Labor (Department) is issuing this notice to announce updates to Appendix A to the Preamble–Education and Training Categories by Occupational Information Network (O*NET)–Standard Occupational Classification (SOC) Occupations. Appendix A is a list of professional occupations that serves as a guide for employers to distinguish between professional and non-professional occupations in order to comply with the professional recruitment requirements of the permanent labor certification (PERM) program. In addition, this notice announces standard procedures for establishing Job Zones for a SOC code and occupational title in situations where O*NET Job Zone data are not yet available as O*NET transitions to the 2018 SOC system. These actions, updating Appendix A and establishing standard procedures for Job Zone values where O*NET Job Zone data are unavailable for certain occupations, will allow ETA to maintain a more comprehensive and current list of occupations and provide additional clarity to employers and the public regarding the appropriate education requirements and Job Zone value for each SOC code and occupational title.

DATES: This Notice is effective on November 15, 2021.

FOR FURTHER INFORMATION CONTACT: Brian Pasternak, Administrator, Office of Foreign Labor Certification, Employment and Training Administration, Department of Labor, 200 Constitution Avenue NW, Room N–5311, Washington, DC 20210, Telephone: (202) 693–8200 (this is not a toll-free number). Individuals with hearing or speech impairments may access the telephone number above via TTY/TDD by calling the toll-free Federal Information Relay Service at 1 (877) 889–5627.

SUPPLEMENTARY INFORMATION:

I. Statutory Background

The Immigration and Nationality Act (INA), as amended, assigns responsibilities to the Secretary of Labor (Secretary) relating to the entry and employment of certain categories of immigrants and nonimmigrants. The INA prohibits the admission of certain employment-based immigrants unless the Secretary has certified that (1) there are not sufficient workers who are able, willing, qualified and available at the time of application for a visa and admission to the United States and at

the place where the foreign worker is to perform such skilled or unskilled labor, and (2) the employment of such foreign worker will not adversely affect the wages and working conditions of workers in the United States similarly employed.[1] The Secretary has delegated the responsibilities under the INA to administer the PERM program at 20 CFR part 656 to the Assistant Secretary for ETA, who in turn has delegated that authority to OFLC.[2]

II. Appendix A

A. Origin and Purpose of Appendix A

On December 27, 2004, the Department published the Final Rule, *Labor Certification for the Permanent Employment of Aliens in the United States; Implementation of New System,* 69 FR 77326 (December 27, 2004) (Final Rule), revising the regulations at 20 CFR part 656. The Final Rule requires employers to conduct recruitment of U.S. workers before filing their applications under the PERM program and introduced different recruitment requirements for non-professional occupations and professional occupations.[3] In the preamble to the Final Rule, the Department included an appendix titled Appendix A, which listed O*NET occupations using BLS 2000 SOC codes and titles for which a bachelor's or higher degree is a customary requirement, and for which the employer must recruit under the standards for professional occupations under 20 CFR 656.17(e)(1). The Department explained that the list was intended to identify professional occupations the Department considered appropriate for recruiting under the standards for professional occupations and offered the list as a guide for employers to determine recruitment requirements.[4]

The Department created Appendix A using a list of occupations that BLS developed based on the usual education and training requirements for the occupations.[5] As the Department explained, each of the occupations listed in Appendix A was assigned a BLS education and training category (E&TC) code, which indicated the ''most significant source of level of education or training'' required by an occupation.[6] In 2010, BLS ceased publishing the education requirements for SOC codes under the E&TC system. However, BLS now publishes the typical entry-level educational requirements for SOC codes in conjunction with the annual wage estimates based on the Occupational Employment and Wage Statistics (OEWS) wage survey.[7]

B. Use of Appendix A

OFLC processes the PERM labor certification application, Form ETA–9089, *Application for Permanent Employment Certification,*[8] and uses Appendix A to determine whether the SOC code assigned to the requested job opportunity[9] in the application generally requires a bachelor's degree for entry, such that the employer must conduct professional recruitment under 20 CFR 656.17(e)(1).[10] The absence of an occupation from Appendix A is not dispositive of an employer's recruitment obligations. However, if the occupation is not listed in Appendix A, as updated and posted annually as notice(s) on the OFLC website, and it does not otherwise meet the definition of a professional occupation under 20 CFR 656.3, the employer is not required to conduct professional recruitment.[11]

C. Availability of New Education Data and the Department's Decision To Update Appendix A

ETA believes it is necessary to publish this notice to provide the best available information to guide employers in determining recruitment requirements under the PERM program, especially as the list of occupations in Appendix A has become outdated. For example, an increasing number of occupational codes are no longer listed by the same SOC code and occupational title in Appendix A due to updates to the SOC manual in 2010 and 2018.[12] Accordingly, it had become necessary for OFLC to develop a method to crosswalk occupations (*i.e.,* connecting an outdated occupation to the O*NET database to find an occupation that best matches the job opportunity indicated in the employer's application). However, with the BLS publication of the typical entry-level educational requirement in conjunction with its annual OEWS wage estimates for the SOC codes and titles, ETA is now able to provide notice of corresponding updates to Appendix A, which are based on occupational and education data from BLS, and maintain a more current list of professional occupations that provides greater clarity to the public on the appropriate education

[1] *See* 8 U.S.C. 1182(a)(5)(A); 8 U.S.C. 1101(a)(15)(E)(iii), (H)(i)(b), (H)(i)(b)(1).

[2] *See* Secretary's Order 06–2010 (Oct. 20, 2010).

[3] The term ''professional occupation'' is defined as ''an occupation for which the attainment of a bachelor's or higher degree is a *usual education requirement.*'' 20 CFR 656.3 (emphasis added). As explained in the Final Rule, and codified at 20 CFR 656.3, it is not a requirement that the foreign worker-beneficiary listed on an application possess a bachelor's or higher degree themselves for the job opportunity to meet the definition of a professional occupation. *Id.;* 69 FR 77326, 77345–46 (Dec. 27, 2004). However, if an employer is willing to accept work experience in lieu of a bachelor's or higher degree, such work experience ''must be attainable in the U.S. labor market and must be stated on the application form.'' 20 CFR 656.3. Similarly, if an equivalent foreign degree is acceptable, this also ''must be clearly stated on the *Application for Permanent Employment Certification* form.'' *Id.* In comparison, the term ''nonprofessional occupation'' means ''any occupation for which the attainment of a bachelor's or higher degree is not a usual requirement for the occupation.'' *Id.;* 69 FR 77326, 77345–46.

[4] *See* 69 FR 77326, 77345–46 (''The primary purpose of the list of occupations is to provide employers with the necessary information to determine whether to recruit under the standards provided in the regulations for professional occupations or for nonprofessional occupations.'').

[5] *See Notice of Proposed Rulemaking, Labor Certification for the Permanent Employment of Aliens in the United States; Implementation of New System,* 67 FR 30466, 30471 (May 6, 2002).

[6] *See id.;* Comment Request, 75 FR 60139, 60140 (Sept. 29, 2010). *See also Employment Projections through the Lens of Education and Training,* 15, Monthly Labor Review: April 2012, Bureau of Labor Statistics (explaining the reasons for development of the current education and training system and the differences between the old and new systems), *available at https://www.bls.gov/opub/mlr/2012/article/employment-projections-through-the-lens-of-education-and-training.htm; Employment Projections: Methods,* Bureau of Labor Statistics (explaining that the current system ''replaced [the] earlier system that was used between 1995 and 2008'' and the ''two systems are not comparable''), *available at https://www.bls.gov/emp/documentation/education/tech.htm.*

[7] BLS's OEWS survey was named the Occupational Employment Statistics survey prior to March 31, 2021. *See https://www.bls.gov/oes/home.htm.*

[8] The current form title is ETA Form 9089, but the Department recently submitted proposed changes to the form to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act. *See* Agency Information Collection Activities; Submission for OMB Review; Comment Request; Application for Permanent Employment Certification, 86 FR 22714 (Apr. 29, 2021).

[9] Generally, the SOC code assigned to an employer's job opportunity is indicated in the Prevailing Wage Determination issued by OFLC's National Prevailing Wage Center.

[10] OFLC's National Prevailing Wage Center (NPWC) also consults the list of occupations in Appendix A to determine the education and experience norms for occupations when it processes prevailing wage determination requests, Form ETA–9141, *Application for Prevailing Wage Determination.* Specifically, NPWC uses the E&TC codes on the list of occupations in its determination of prevailing wages by comparing an employer's education requirement listed on the Form ETA–9141 with the education requirement indicated on the E&TC code for that occupation. Employment and Training Administration; Prevailing Wage Determination Policy Guidance, Nonagricultural Programs (Revised Nov. 2009), *available at https://www.dol.gov/sites/dolgov/files/ETA/oflc/pdfs/NPWHC_Guidance_Revised_11_2009.pdf.*

[11] *See* 20 CFR 656.17(e)(2) (recruitment obligations for nonprofessional occupations); 69 FR 77326, 77388 (listing definitions of ''professional occupation'' and ''nonprofessional occupation'').

[12] *See, e.g.,* Standard Occupational Classification Manual (2018), *available at https://www.bls.gov/soc/2018/soc_2018_manual.pdf.*

requirements for each occupation.[13] ETA intends to annually review the BLS occupational and education data with the annual OEWS wage estimates each May and, as appropriate, publish a full update to Appendix A consistent with the BLS data, even if BLS data have not changed from the previous year.

D. Effective Date of the Updated List of Occupations in Appendix A

The updated list of occupations in Appendix A will be published on OFLC's website on or before June 30, 2022, along with the wage data applicable in the new wage year, which starts July 1, 2022 and continues until June 30, 2023. Employers will be able to rely on the list of occupations and the education requirements associated with the occupations in Appendix A that OFLC publishes each year on its website. In order to minimize the impact of newly-added professional occupations and to ensure appropriate notice for employers, including those engaged in any pre-filing recruitment under 20 CFR 656.17(e), professional recruitment obligations under 20 CFR 656.17(e)(1) will generally not apply to professional occupations that are newly added to the list of professional occupations in Appendix A unless OFLC has both: (1) Published the occupation on a list of professional occupations as a notice on the OFLC website; and (2) OFLC's National Prevailing Wage Center (NPWC) has assigned the SOC code in connection with the issuance of a prevailing wage determination under 20 CFR 656.40. As the Department explained in the Final Rule, ''[t]he primary purpose of the list of occupations [in Appendix A] is to provide employers with the necessary information to determine whether to recruit under the standards provided in the regulations for professional occupations or for nonprofessional occupations.'' 69 FR 77326, 77346. However, ''[e]mployers that conduct more recruitment than is required will not have their applications denied for that reason. Employers filing applications involving nonprofessional occupations are free to recruit under the requirements for professional occupations if they believe by so doing it will yield more applications from willing, able, and qualified U.S. workers.'' *Id.* Accordingly, ETA believes that providing this notice to annually review and publish a new list of professional occupations in Appendix A on OFLC's website—even when BLS data have not changed from the previous year—will provide employers with the best available information to guide them in determining recruitment requirements and wage obligations. Specifically, OFLC will use BLS's latest occupational and education data annually, beginning in the July 2022 through June 2023 wage year, when the wages are updated based upon the same BLS release cycle.

III. Job Zones

*A. O*NET Five Job Zones*

A Job Zone is a group of occupations that are similar in the amount of (1) education; (2) related experience; and (3) on-the-job training that is needed to perform the work. O*NET classifies occupations into one of five Job Zones, ranging from little or no preparation to an extensive amount of preparation needed to perform the job. Job Zone One occupations require little or no preparation to perform the job. Job Zone Two occupations require some preparation. Job Zone Three occupations require medium preparation. Job Zone Four occupations require considerable preparation, and Job Zone Five occupations require extensive preparation to perform the job.[14]

More specifically, Job Zone One occupations may require: (1) A high school diploma or GED certificate; (2) minimal work-related skill, knowledge, or experience; and (3) a few days to a few months of job training. Examples of Job Zone One occupations include: Dishwashers, sewing machine operators, and landscaping and groundskeeping workers. Job Zone Two occupations usually require: (1) A high school diploma; (2) some previous work-related skill, knowledge, or experience; and (3) a few months to one year of working. Examples of Job Zone Two occupations include: Counter and rental clerks, customer service representatives, and security guards. Job Zone Three occupations usually require: (1) Training in vocational schools, related on-the-job experience, or an associate's degree; (2) previous work-related skill, knowledge, or experience; and (3) one or two years of training involving both on-the-job experience and informal training. These occupations usually involve using communication and organizational skills to coordinate, supervise, manage, or train others. Examples of Job Zone Three occupations include: Electricians, court reporters, and medical assistants. Job Zone Four occupations usually require: (1) A four-year bachelor's degree; (2) considerable amount of work-related skill, knowledge, or experience; and (3) several years of work-related experience, on-the-job training, and/or vocational training. These occupations involve coordinating, supervising, managing, or training others. Examples of Job Zone Four occupations include: Sales managers, database administrators, and graphic designers. Job Zone Five occupations usually require: (1) Graduate school; (2) extensive skill, knowledge, and five or more years of experience; and (3) some on-the-job training, but most of these occupations assume that the person will already have the required skills, knowledge, work-related experience, and/or training. These occupations often involve coordinating, training, supervising, or managing the activities of others. Examples of Job Zone Five occupations include: Pharmacists, lawyers, and neurologists.[15]

B. Procedures for Establishing Job-Zone Values

OFLC uses the O*NET Job Zone assigned to an occupation to determine whether the experience the employer requires *meets, exceeds,* or *falls below* requirements typical to the occupation in which the employer's job opportunity is classified. While O*NET transitions to the 2018 SOC occupations, there are many frequently used occupations where the O*NET Job Zone is not yet available. Until O*NET completes its transition, OFLC will use the following standard procedures to set Job Zone values for occupations without O*NET Job Zone data.

First, when there is an existing O*NET Job Zone for a 2018 SOC occupation, OFLC will use the Job Zone from the O*NET 2018 SOC occupation.

Second, when there is no O*NET Job Zone for the 2018 SOC occupation, but there is an O*NET Job Zone for the 2010 SOC occupation, OFLC will use the Job Zone from the O*NET 2010 SOC occupation.

Third, when there is no O*NET Job Zone for either the 2018 SOC occupation or the 2010 SOC occupation, OFLC will first examine the corresponding broad occupation[16] to

[13] *See https://www.bls.gov/oes/additional.htm.*

[14] *See* O*NET OnLine Help: Job Zones, *available at https://www.onetonline.org/help/online/zones.*

[15] *Id.*

[16] SOC occupations are organized into a tiered system with four levels of aggregation: (1) Major group; (2) minor group; (3) broad occupation; and (4) detailed occupation. Each lower level of detail identifies a more specific group of occupations. The 2018 SOC contains 23 major groups, which are broken into 98 minor groups, 459 broad occupations, and 867 detailed occupations, of the latter of which have the highest level of specification. The following is an example of the four levels of aggregation: 29–0000 Healthcare Practitioners and Technical Occupations (major

determine if the broad occupation contains detailed occupations with O*NET Job Zones.[17] OFLC will calculate the Job Zones by averaging the O*NET Job Zones of the detailed occupations within the broad occupation. For example, since there is neither O*NET Job Zone for 2018 SOC 11–3013—Facilities Managers nor O*NET Job Zone for 2010 SOC 11–3011—Administrative Services Manager, OFLC will use the average O*NET Job Zones for the Broad Occupation 11–3010—Administrative Services and Facilities Managers.

Lastly, where there is no O*NET Job Zone for either the 2018 SOC occupation or the 2010 SOC occupation, and the broad occupation does not have detailed occupations with O*NET Job Zones, OFLC will calculate the Job Zone by averaging the O*NET Job Zone of the detailed occupations within the minor group. For example, since the Broad Occupation 15–2051—Data Scientists does not have detailed occupations with O*NET Job Zones, OFLC will use the average O*NET Job Zones for the Minor Group 15–2000—Mathematical Science Occupations.

OFLC intends to use these standard procedures for occupations that do not have O*NET Job Zone data beginning in the July 2022 through June 2023 wage year when the wages are updated based upon the same BLS release cycle.

Angela Hanks,

Acting Assistant Secretary of the Employment and Training Administration.

[FR Doc. 2021–24813 Filed 11–12–21; 8:45 am]

BILLING CODE 4510–FP–P

DEPARTMENT OF LABOR

President's Committee on the International Labor Organization Charter Renewal

AGENCY: Bureau of International Labor Affairs, Labor.

ACTION: Notice of charter renewal.

SUMMARY: On September 30, 2021, President Biden continued the President's Committee on the International Labor Organization (ILO) for two years through September 30, 2023. In response, and pursuant to the Federal Advisory Committee Act (FACA), the Secretary of Labor renewed the committee's charter on November 1, 2021.

Purpose: The President's Committee on the International Labor Organization was established in 1980 by Executive Order (E.O.) 12216 to monitor and assess the work of the ILO and make recommendations to the President regarding United States policy towards the ILO. The committee is chaired by the Secretary of Labor and the Department of Labor's Bureau of International Labor Affairs is responsible for providing the necessary support for the committee.

The committee is composed of seven *ex officio* members: The Secretary of Labor, the Secretary of State, the Secretary of Commerce, the Assistant to the President for National Security Affairs, the Assistant to the President for Economic Policy, and one representative each from organized labor and the business community, designated by the Secretary of Labor. The labor and business members are the presidents of the American Federation of Labor and Congress of Industrial Organizations and the United States Council for International Business, respectively, as the most representative organizations of U.S. workers and employers engaged in ILO matters.

Authority: The authority for this notice is granted by FACA (5 U.S.C. App. 2) and E.O. 14048 of September 30, 2021.

FOR FURTHER INFORMATION CONTACT: Robert B. Shepard, Director, Office of International Relations, Bureau of International Labor Affairs, U.S. Department of Labor, telephone (202) 693–4808, *Shepard.Robert@dol.gov.*

Signed at Washington, DC, on November 2, 2021.

Thea Mei Lee,

Deputy Undersecretary, Bureau of International Labor Affairs.

[FR Doc. 2021–24781 Filed 11–12–21; 8:45 am]

BILLING CODE 4510–28–P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[NOTICE: (21–072)]

Privacy Act of 1974; System of Records

AGENCY: National Aeronautics and Space Administration (NASA).

ACTION: Notice of a Modified System of Records.

SUMMARY: Pursuant to the provisions of the Privacy Act of 1974, the National Aeronautics and Space Administration is issuing public notice of its proposal to significantly alter a previously noticed system of records Reasonable Accommodation (RA) Records/NASA 10RAR to include the provision of religious accommodations under Title VII of the Civil Rights Act of 1964. The prior notice exclusively addressed reasonable accommodations for employees or applicants with disabilities but is being revised to include both types of accommodation requests. This notice adds two new authorities, expands categories of records, updates technical safeguards, updates system and subsystem managers. It adds one location, revises two and deletes two routine uses, all that are unique to this system. This notice incorporates locations and NASA standard routine uses that were previously published separately from, and cited by reference in, this and other NASA systems of records notices. Finally, it revises and adds to previously published Standard Routine Uses. Further details are set forth below under the caption. **SUPPLEMENTARY INFORMATION**.

DATES: Submit comments within 30 calendar days from the date of this publication. The changes will take effect at the end of that period if no adverse comments are received.

ADDRESSES: Patti F. Stockman, Privacy Act Officer, Office of the Chief Information Officer, Mary W. Jackson NASA Headquarters, Washington, DC 20546–0001, (202) 358–4787, *NASA-PAOfficer@nasa.gov.*

FOR FURTHER INFORMATION CONTACT: NASA Privacy Act Officer, Patti F. Stockman, (202) 358–4787, *NASA-PAOfficer@nasa.gov.*

SUPPLEMENTARY INFORMATION: One of the most significant changes to the notice is that it now includes requests made by employees or applicants for religious accommodations in accordance with Title VII of the Civil Rights Act of 1964. The information collected will be used to document and evaluate a request for accommodation. The prior notice exclusively addressed reasonable accommodations for employees or applicants with disabilities but is being revised to include medical and religious accommodation requests. This system notice therefore adds both 42 U.S.C. 2000e *et seq.* and 29 CFR pt. 1605 as authorities. It deletes Routine Uses 1 and 3 unique to this system of records

group); 29–1000 Healthcare Diagnosing or Treating Practitioners (minor group); 29–1020 Dentists (broad occupation); and 29–1022 Oral and Maxillofacial Surgeons (detailed occupation). *See* Standard Occupational Classification Manual (2018), *available at https://www.bls.gov/soc/2018/soc_2018_manual.pdf; see also* The O*NET SOC Taxonomy, *available at https://www.onetcenter.org/taxonomy.html* (providing additional information on classification).

[17] *See* Updating the O*NET®-SOC Taxonomy: Incorporating the 2018 SOC Structure—Summary and implementation, at 6–7, *available at https://www.onetcenter.org/dl_files/Taxonomy2019_Summary.pdf.*

as they are duplicated by NASA's Standard Routine Uses; revises newly renumbered Routine Use 1 that is unique to this system of records to indicate release of records from appeals by either employees or applicants; and revises renumbered Routine Use 3 that is unique to this system of records to allow disclosure of records to Federal officials or their assignees responsible for ensuring compliance under Title VII of the Civil Rights Act. This notice expands categories of records to include information associated with accommodation based on sincerely held religious beliefs, practices, or observances. It adds a new cloud location; and updates System Manager(s) and Physical Safeguards to reflect current manager titles and current information technology security protocols. It incorporates in whole, as appropriate, information formerly published separately in the **Federal Register** as Appendix A, Location Numbers and Mailing Addresses of NASA Installations at which Records are Located, and Appendix B, Standard Routine Uses—NASA. This notice revises Standard Routine Use 4 to clarify conditions under which NASA will release records to a legal body for a proceeding involving NASA and revises Standard Routine Use 5 to clarify potential release of records to legal or administrative bodies in the course of civil or legal proceedings. This notice revises Standard Routine Use 6 and adds new Standard Routine Use 9, both to enable the Agency to release records as necessary (1) to respond to a breach of the agency's personally identifiable information (PII) or (2) to assist another agency in response to a breach of its PII. Finally, this notice adds new Standard Routine Uses 10 and 11 allowing release to other agencies to aid their functions of inspection, audit or oversight as authorized by law. Finally, minor revisions to NASA's existing system of records notice bring its format into compliance with OMB guidance and update records access, notification, and contesting procedures consistent with NASA Privacy Act regulations.

Cheryl Parker,

Federal Register Liaison Officer.

SYSTEM NAME AND NUMBER:

Reasonable Accommodation (RA) Records, NASA 10RAR.

SECURITY CLASSIFICATION:

None.

SYSTEM LOCATION:

Amazon Web Services, 410 Terry Avenue North, Seattle, WA 98109;

Mary W. Jackson NASA Headquarters, Washington, DC 20546–0001;

Ames Research Center (NASA), Moffett Field, CA 94035–1000;

Armstrong Flight Research Center (NASA), PO Box 273, Edwards, CA 93523–0273;

John H. Glenn Research Center at Lewis Field (NASA), 21000 Brookpark Road, Cleveland, OH 44135–3191;

Goddard Space Flight Center (NASA), Greenbelt, MD 20771–0001;

Lyndon B. Johnson Space Center (NASA), Houston, TX 77058–3696;

John F. Kennedy Space Center (NASA), Kennedy Space Center, FL 32899–0001;

Langley Research Center (NASA), Hampton, VA 23681–2199;

George C. Marshall Space Flight Center (NASA), Marshall Space Flight Center, AL 35812–0001;

John C. Stennis Space Center (NASA), Stennis Space Center, MS 39529–6000;

NASA Shared Services Center (NSSC), Building 5100, Stennis Space Center, MS 39529–6000; and

Wallops Flight Facility (NASA), Wallops Island, VA 23337.

SYSTEM MANAGER(S):

Associate Administrator, Office of Diversity and Equal Opportunity (ODEO), NASA Headquarters (see System Location above for address).

Subsystem Managers: ODEO Director, Diversity and Data Analytics Division; and Agency Disability Program Manager at NASA Headquarters (see System Location above for address);

Center ODEO Directors and Center Disability Program Managers, at:

NASA Ames Research Center (see System Location above for address);

NASA Armstrong Flight Research Center (see System Location above for address);

NASA Glenn Research Center (see System Location above for address);

NASA Goddard Space Flight Center (see System Location above for address);

NASA Headquarters (see System Location above for address);

NASA Johnson Space Center (see System Location above for address);

NASA Kennedy Space Center (see System Location above for address);

NASA Langley Research Center (see System Location above for address);

NASA Marshall Space Flight Center (see System Location above for address);

NASA Stennis Space Center (see System Location above for address);

NASA Shared Services Center (NSSC) (see System Location above for address); and

Wallops Flight Facility (see System Location above for address).

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

29 U.S.C. 791 *et seq.;* 42 U.S.C. 12101 *et seq.;* 42 U.S.C. 2000e *et seq.;* 44 U.S.C. 3101; 51 U.S.C. 20113(a); Exec. Order No. 11478; Exec. Order No. 13164; 29 CFR pt. 1605; 29 CFR pt. 1614; 29 CFR pt. 1630.

PURPOSE(S) OF THE SYSTEM:

This system is maintained for the purpose of considering, deciding and implementing requests for reasonable accommodation made by NASA employees and applicants for employment.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

This system maintains records of requests by (1) NASA employees; or (2) applicants for employment who are seeking reasonable accommodation and also contains the disposition of such requests.

CATEGORIES OF RECORDS IN THE SYSTEM:

Records may include, but are not limited to: Requests for reasonable accommodation including supporting documents for such requests; information concerning the nature of the disability or religious belief, practice, or observance and the need for accommodation; medical records or other substantiating documentation; notes or records made during evaluation of such requests; requests for reconsideration or internal Agency appeals; and disposition all requests and appeals.

RECORD SOURCE CATEGORIES:

Individuals themselves; Associate Administrator for Diversity and Equal Opportunity, and all designees, including NASA Center E.O. Directors and Center Disability Program Managers; EEOC officials.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORES OF USERS AND PURPOSES OF SUCH USES:

Any disclosures of information will be compatible with the purpose for which the Agency collected the information. Under the following routine uses that are unique to this system of records, information in this system may be disclosed: (1) To an authorized appeal grievance examiner, formal complaints examiner, administrative judge, equal employment opportunity investigator, arbitrator or other duly authorized official engaged in investigation or settlement of a grievance, complaint or appeal filed by an employee or applicant; (2) to first aid and safety personnel, when appropriate, if the disability might require emergency treatment; (3) to Federal

Government officials or any of their assignees charged with the responsibility of investigating NASA's compliance with The Rehabilitation Act of 1973, as amended, or the Genetic Information Nondiscrimination Act of 2008 (GINA), or Title VII of the Civil Rights Act; (4) to the Office of Management and Budget (OMB), Department of Labor (DOL), Office of Personnel Management (OPM), Equal Employment Opportunity Commission (EEOC), or Office of Special Counsel (OSC) to obtain advice regarding statutory, regulatory, policy, and other requirements related to reasonable accommodation; and (5) in accordance with NASA standard routine uses as set forth here.

In addition, the following routine uses of information contained in SORs, subject to the Privacy Act of 1974, are standard for many NASA systems. Any disclosures of information will be compatible with the purpose for which the Agency collected the information.

Standard Routine Use No. 1—In the event this system of records indicates a violation or potential violation of law, whether civil, criminal, or regulatory in nature, and whether arising by general statute or particular program statute, or by regulation, rule or order issued pursuant thereto, the relevant records in the SOR may be referred to the appropriate agency, whether Federal, State, local or foreign, charged with the responsibility of investigating or prosecuting such violation or charged with enforcing or implementing the statute, or rule, regulation or order issued pursuant thereto.

Standard Routine Use No. 2—A record from this SOR may be disclosed to a Federal, State, or local agency maintaining civil, criminal, or other relevant enforcement information or other pertinent information, such as current licenses, if necessary to obtain information relevant to an agency decision concerning the hiring or retention of an employee, the issuance of a security clearance, the letting of a contract, or the issuance of a license, grant, or other benefit.

Standard Routine Use No. 3—A record from this SOR may be disclosed to a Federal agency, in response to its request, in connection with the hiring or retention of an employee, the issuance of a security clearance, the reporting of an investigation of an employee, the letting of a contract, or the issuance of a license, grant, or other benefit by the requesting agency, to the extent that the information is relevant and necessary to the requesting agency's decision on the matter.

Standard Routine Use No. 4—A record from this system may be disclosed to the Department of Justice including United States Attorney Offices, or other federal agency conducting litigation or in proceedings before any court, adjudicative or administrative body, when the record is relevant or necessary to the litigation or the agency has an interest in such litigation when (a) the Agency, or any component thereof; or (b) any employee or former employee of the Agency in his or her official capacity; or (c) any employee of the Agency in his or her individual capacity where the Department of Justice or the Agency has agreed to represent the employee; or (d) the United States, where the Agency determines that litigation is likely to affect the Agency or any of its components, is a party to litigation or has an interest in such litigation, and the use of such records by the Department of Justice or the Agency is deemed by the Agency to be relevant and necessary to the litigation.

Standard Routine Use No. 5—A record from this SOR may be disclosed in an appropriate proceeding before a court, grand jury, or administrative or adjudicative body, when NASA determines that the records are relevant to the proceeding; or in an appropriate proceeding before an administrative or adjudicative body when the adjudicator determines the records to be relevant to the proceeding.

Standard Routine Use No. 6—A record from this SOR may be disclosed to appropriate agencies, entities, and persons when (1) NASA suspects or has confirmed that there has been a breach of the system of records; (2) NASA has determined that as a result of the suspected or confirmed breach there is a risk of harm to individuals, NASA (including its information systems, programs, and operations), the Federal Government, or national security; and (3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with NASA's efforts to respond to the suspected or confirmed breach or to prevent, minimize, or remedy such harm.

Standard Routine Use No. 7—A record from this system may be disclosed to contractors, grantees, experts, consultants, students, and others performing or working on a contract, service, grant, cooperative agreement, or other assignment for the federal government, when necessary to accomplish an Agency function related to this system of records.

Standard Routine Use No. 8—A record from this system may be disclosed to a Member of Congress or staff acting upon the Member's behalf when the Member or staff requests the information on behalf of, and at the request of, the individual who is the subject of the record.

Standard Routine Use No. 9—A record from this system may be disclosed to another Federal agency or Federal entity, when NASA determines that information from this system of records is reasonably necessary to assist the recipient agency or entity in (1) responding to a suspected or confirmed breach or (2) preventing, minimizing, or remedying the risk of harm to individuals, the recipient agency or entity (including its information systems, programs, and operations), the Federal Government, or national security, resulting from a suspected or confirmed breach.

Standard Routine Use No. 10—To the National Archives and Records Administration (NARA) or the General Services Administration (GSA) pursuant to records management inspections being conducted under the authority of 44 U.S.C. 2904 and 2906.

Standard Routine Use No. 11—To another agency, or organization for purpose of performing audit or oversight operations as authorized by law, but only such information as is necessary and relevant to such audit or oversight function.

POLICIES AND PRACTICES FOR STORAGE OF RECORDS:

Records in this system are maintained in hard-copy and electronically, and within Agency-wide Intranet database and tracking system.

POLICIES AND PRACTICES FOR RETRIEVAL OF RECORDS:

Records in the system are retrieved by name of the employee or applicant requesting accommodation, case identification number, or NASA Center from which the request originated.

POLICIES AND PRACTICES FOR RETENTION AND DISPOSAL OF RECORDS:

Records are maintained and destroyed in accordance with NPR 1441.1 NASA Records Retention Schedules, Schedule 3 Item 2.6.

ADMINISTRATIVE, TECHNICAL, AND PHYSICAL SAFEGUARDS:

Electronic records are maintained on secure NASA servers and protected in accordance with all Federal standards and those established in NASA regulations at 14 CFR 1212.605. Additionally, server and data management environments employ infrastructure encryption technologies both in data transmission and at rest on

servers. Electronic messages sent within and outside of the Agency are encrypted and transmitted by staff via pre-approved electronic encryption systems as required by NASA policy. Approved security plans are in place for information systems containing the records in accordance with the Federal Information Security Management Act of 2002 (FISMA) and OMB Circular A–130, Management of Federal Information Resources. Only authorized personnel requiring information in the official discharge of their duties are authorized access to records through approved access or authentication methods. Access to electronic records is achieved only from workstations within the NASA Intranet or via a secure Virtual Private Network (VPN) connection that requires two-factor hardware token authentication. Non-electronic records are secured in locked rooms or locked file cabinets.

RECORD ACCESS PROCEDURES:

In accordance with 14 CFR part 1212, Privacy Act—NASA Regulations, information may be obtained by contacting in person or in writing the system or subsystem manager listed above at the location where the records are created and/or maintained. Requests must contain the identifying data concerning the requester, *e.g.,* first, middle, and last name; date of birth; description and time periods of the records desired. NASA Regulations also address contesting contents and appealing initial determinations regarding records access.

CONTESTING RECORD PROCEDURES:

In accordance with 14 CFR part 1212, Privacy Act—NASA Regulations, information may be obtained by contacting in person or in writing the system or subsystem manager listed above at the location where the records are created and/or maintained. Requests must contain the identifying data concerning the requester, *e.g.,* first, middle and last name; date of birth; description and time periods of the records desired. NASA Regulations also address contesting contents and appealing initial determinations regarding records access.

NOTIFICATION PROCEDURES:

In accordance with 14 CFR part 1212, Privacy Act—NASA Regulations, information may be obtained by contacting in person or in writing the system or subsystem manager listed above at the location where the records are created and/or maintained. Requests must contain the identifying data concerning the requester, *e.g.,* first, middle, and last name; date of birth; description and time periods of the records desired. NASA Regulations also address contesting contents and appealing initial determinations regarding records access.

EXEMPTIONS PROMULGATED FOR THE SYSTEM:

None.

HISTORY:

(15–117, 80 FR 246, pp. 79947–79949)
(15–068, 80 FR 193, pp. 60410–60411)
(11–091, 76 FR 200, pp. 64112–64114)

[FR Doc. 2021–24867 Filed 11–12–21; 8:45 am]

BILLING CODE 7510–13–P

NATIONAL CRIME PREVENTION AND PRIVACY COMPACT COUNCIL

Fingerprint Submission Requirements

AGENCY: National Crime Prevention and Privacy Compact Council.

ACTION: Notice of approval of the Oklahoma proposal.

SUMMARY: As a result of the Coronavirus (COVID–19) pandemic, the National Crime Prevention and Privacy Compact Council (Compact Council) approves a proposal submitted by the Oklahoma State Bureau of Investigation, under the previously approved Florida proposal as amended by the subsequent Florida proposal, requesting access to the Interstate Identification Index (III) System, maintained by the Federal Bureau of Investigation (FBI), on a delayed fingerprint submission basis for emergency child placement purposes.

FOR FURTHER INFORMATION CONTACT: Inquiries may be addressed to Mrs. Chasity S. Anderson, FBI Compact Officer, Biometric Technology Center, 1000 Custer Hollow Road, Clarksburg, West Virginia 26306, telephone 304–625–2803.

SUPPLEMENTARY INFORMATION: Title 28, Code of Federal Regulations (CFR), part 901, specifically § 901.3, gives authority to the Compact Council, established by the National Crime Prevention and Privacy Compact Act of 1998 (Compact), to approve proposals for delayed submission of fingerprints supporting requests for III records by agencies authorized to access and receive criminal history records under Public Law 92–544. The proposals must fully describe the emergency nature of the situation in which delayed submission authority is being sought, the risk to health and safety of the individuals involved, and the reasons why the submission of fingerprints contemporaneously with the search request is not feasible. The Oklahoma proposal makes such a request when conducting criminal history record checks in connection with temporary placement of children in exigent circumstances. Due to the national COVID–19 emergency and limiting close contact with another person, as well as the unavailability or limited availability of noncriminal justice fingerprinting services, the Oklahoma proposal temporarily expands the 15-calendar day requirement as noted in the amended Florida proposal during the coronavirus pandemic. The Oklahoma proposal was submitted by email dated March 27, 2020, and approved by the Compact Council on November 4, 2020, pursuant to 28 CFR 901.2 and 901.3. Access to the III System to conduct name-based criminal history record checks, followed by fingerprint submissions, provides a responsive and timely avenue to determine whether a person presents a risk to children during exigent circumstances when time is of the essence. Pursuant to the Oklahoma proposal, such name-based checks will be followed by the submission of the person's fingerprints to the FBI as soon as possible, but not later than 180-calendar days from the date of the preliminary III name-based check, or 90-calendar days from the expiration of the state's emergency declaration, whichever occurs sooner.

Authority: 34 U.S.C. 40316.

Dated: October 27, 2021.

Leslie Moore,

Compact Council Chairman.

Proposal From Oklahoma to the National Crime Prevention and Privacy Compact Council Under the Fingerprint Submission Requirements Rule

As a result of the Coronavirus pandemic, and the declaration of a state of emergency, the Oklahoma State Bureau of Investigation requests temporary approval under the previously approved Florida Proposal published in the **Federal Register** (FR) Notice dated May 21, 2001 (66 FR 28004), as amended by the subsequent Florida Proposal dated August 8, 2003 (68 FR 47369), which was submitted pursuant to the National Crime Prevention and Privacy Compact (Compact) Council's (Council) Fingerprint Submission Requirements Rule (Rule) (Title 28, Code of Federal Regulations [CFR], Part 901). The previously approved proposal provided for the delayed submission of fingerprints to the FBI within 15-calendar days of conducting preliminary Interstate Identification Index (III) name-based checks when conducting criminal history record checks in

connection with the temporary placement of children during exigent circumstances. This request is for the sole purpose of temporarily expanding the ''15-calendar days'' to as soon as possible, but not later than 180-calendar days during the Coronavirus pandemic, or 90-calendar days from the expiration of the state's emergency declaration, whichever occurs sooner. In addition, the state recognizes the risk associated with a name-based check; however, due to the national pandemic and the initiative to limit close contact with another person, as well as the unavailability or limited availability of noncriminal justice fingerprinting services, it is imperative that a preliminary III name-based check be conducted.

The preliminary III name-based check and submission of follow-up fingerprints shall be conducted in accordance with state laws and procedures. The state will continue to be responsible for submitting the follow-up fingerprints in the time frame specified by the Council.

The individual(s) will be required to be fingerprinted as soon as possible, but not later than 180-calendar days from the date of the preliminary III name-based check, or 90-calendar days from the expiration of the state's emergency declaration, whichever occurs sooner. Once obtained, the fingerprints must be immediately submitted to the state repository which will either positively identify the fingerprinted subject or will forward the fingerprints to the FBI.

All other provisions of the approved original Florida Proposal and the approved amended Florida Proposal will remain intact, including the Council's policy guidance for use of the Rule.

Those state agencies previously authorized access to the III pursuant to 28 CFR 901.3, wishing to take advantage of the extended time frame, must submit new written requests to the FBI Compact Officer. Approvals to utilize this amended proposal will expire 30-calendar days from the date the state cancels its emergency declaration.

If the Council does not approve this temporary proposal during its next public-held meeting, this temporary proposal will expire immediately.

[FR Doc. 2021–24725 Filed 11–12–21; 8:45 am]

BILLING CODE 4410–02–P

NATIONAL CRIME PREVENTION AND PRIVACY COMPACT COUNCIL

Fingerprint Submission Requirements

AGENCY: National Crime Prevention and Privacy Compact Council.

ACTION: Notice of approval of the Colorado proposal.

SUMMARY: The National Crime Prevention and Privacy Compact Council (Compact Council) approves a proposal submitted by the Colorado Bureau of Investigation requesting access to the Interstate Identification Index (III) System, maintained by the Federal Bureau of Investigation (FBI), on a delayed fingerprint submission basis for the sole purpose of conducting criminal history record checks of individuals, to include volunteers, for limited critical positions, as defined by the state, in response to the coronavirus (COVID–19) pandemic.

FOR FURTHER INFORMATION CONTACT: Inquiries may be addressed to Mrs. Chasity S. Anderson, FBI Compact Officer, Biometric Technology Center, 1000 Custer Hollow Road, Clarksburg, West Virginia 26306, telephone 304–625–2803.

SUPPLEMENTARY INFORMATION: Title 28, Code of Federal Regulations (CFR), part 901, specifically § 901.3, gives authority to the Compact Council, established by the National Crime Prevention and Privacy Compact Act of 1998 (Compact), to approve proposals for delayed submission of fingerprints supporting requests for III records by agencies authorized to access and receive criminal history records under Public Law 92–544. The proposals must fully describe the emergency nature of the situation in which delayed submission authority is being sought, the risk to health and safety of the individuals involved, and the reasons why the submission of fingerprints contemporaneously with the search request is not feasible. The Colorado proposal makes such a request when conducting criminal history record checks of individuals, to include volunteers, for limited critical positions that have access to our nation's most vulnerable populations such as children, the elderly, and the disabled. Due to the national COVID–19 emergency and limiting close contact with another person, as well as the unavailability or limited availability of noncriminal justice fingerprinting services, the Colorado proposal temporarily allows for the delayed submission of fingerprints during the COVID–19 pandemic.

The Colorado proposal was submitted by email dated March 27, 2020, and approved by the Compact Council on November 4, 2020, pursuant to 28 CFR 901.2 and 901.3. Access to the III System to conduct name-based criminal history record checks, followed by fingerprint submissions, provides a responsive and timely avenue to determine whether an applicant presents a risk to vulnerable populations. Pursuant to the Colorado proposal, such name-based checks must be followed by the submission of the applicant's fingerprints to the FBI as soon as possible, but not later than 180-calendar days from the date of the preliminary III name-based check, or 90-calendar days from the expiration of the state's emergency declaration, whichever occurs sooner. Should an individual refuse or fail to submit the follow-up fingerprints in the time frame specified by the Council, the individual will no longer be permitted to hold the position for which the preliminary name-based criminal history record check was conducted.

Authority: 34 U.S.C. 40316.

Dated: October 27, 2021.

Leslie Moore,

Compact Council Chairman.

Proposal From Colorado to the National Crime Prevention and Privacy Compact Council Under the Fingerprint Submission Requirements Rule

As a result of the Coronavirus pandemic, and the declaration of a state of emergency, the Colorado Bureau of Investigation requests temporary approval under the National Crime Prevention and Privacy Compact Council's (Council) Fingerprint Submission Requirements Rule (Rule) (Title 28, Code of Federal Regulations [CFR], Part 901), to access the Interstate Identification Index (III) on a delayed fingerprint submission basis. This proposal is for the sole purpose of conducting criminal history record checks of individuals, to include volunteers, for limited critical positions, as defined by the state, in response to the Coronavirus pandemic (*i.e.,* healthcare workers, child care workers, etc.) as specifically identified in a state statute previously approved pursuant to Public Law (Pub. L.) 92–544. In the absence of an approved Pub. L. 92–544 state statute, a state may utilize the National Child Protection Act/Volunteers for Children Act for those positions that the covered individual has responsibility for the safety and well-being of children, the elderly, or individuals with disabilities.

In addition, the state recognizes the risk associated with a name-based check; however, due to the national pandemic and the initiative to limit close contact with another person, as well as the unavailability or limited availability of noncriminal justice fingerprinting services, to protect the health and safety of children or other vulnerable populations it is imperative that a preliminary III name-based check be conducted.

The use of the preliminary III name-based check shall be conducted by the State Identification Bureau or CJIS Systems Agency and will not replace the requirement for a noncriminal justice fingerprint-based background check to be conducted. The state will continue to be responsible for submitting the follow-up fingerprints in the time frame specified by the Council. In addition, the state will verify the use of the III name-based check and the time frame established for the delayed submission of fingerprints, in this situation, does not conflict with existing state laws.

Pursuant to the Privacy Act of 1974 (Title 5, United States Code, Section 552a), the individual must be provided with an adequate written FBI Privacy Act statement when he/she provides the required personal information to perform the III name-based check. In addition, the individual must be informed in writing of his/her rights pursuant to 28 CFR 50.12, including the right to access and amend his/her criminal history records.

An individual will be required to be fingerprinted as soon as possible, but not later than 180-calendar days from the date of the preliminary III name-based check, or 90-calendar days from the expiration of the state's emergency declaration, whichever occurs sooner. Once obtained, the fingerprints must be immediately submitted to the state repository which will either positively identify the fingerprinted subject or will forward the fingerprints to the FBI. In addition, the agency must advise the individual that fingerprints are required to be submitted even if the individual is no longer employed or licensed.

Should an individual refuse or fail to submit the follow-up fingerprints in the time frame specified by the Council, the individual will no longer be permitted to hold the position for which the preliminary III name-based check was conducted. Should this occur, the agency must abide by the Council's policy guidance for use of the Rule, as appropriate.

Approvals to utilize this proposal will expire 30-calendar days from the date the state cancels its emergency declaration.

If the Council does not approve this temporary proposal during its next public-held meeting, this temporary proposal will expire immediately.

[FR Doc. 2021–24723 Filed 11–12–21; 8:45 am]

BILLING CODE 4410–02–P

NATIONAL TRANSPORTATION SAFETY BOARD

[Docket No.: NTSB–2021–0007]

Privacy Act of 1974; System of Records

AGENCY: National Transportation Safety Board (NTSB).

ACTION: Notice of new system of records.

SUMMARY: The National Transportation Safety Board (NTSB) proposes adding a new system of records to its inventory of system of records: Religious Accommodation Request Records. Subject to the Privacy Act of 1974, the agency proposes this new system for reasonable accommodations from prospective, current, and former NTSB employees who request or receive accommodations for sincerely held religious beliefs, practices, or observances.

DATES: This system is effective on November 15, 2021, with the exception of the routine uses which will be effective on December 15, 2021. Submit written comments by December 15, 2021.

ADDRESSES: You may send comments, identified by Docket Number (No.) NTSB–2021–0007, by any of the following methods:

- *Federal e-Rulemaking Portal: https://www.regulations.gov.*
- *Email: rulemaking@ntsb.gov.*
- *Fax:* 202–314–6090.
- *Mail/Hand Delivery/Courier:* NTSB, Office of General Counsel, 490 L'Enfant Plaza East SW, Washington DC 20594.

Instructions: All submissions in response to this Notice must include Docket No. NTSB–2021–0007. All comments received will be posted without change to *https://www.regulations.gov,* including any personal information provided.

Docket: For access to the docket, including comments received, go to *https://www.regulations.gov* and search under Docket No. NTSB–2021–0007.

FOR FURTHER INFORMATION CONTACT: Kathleen Silbaugh, General Counsel, (202) 314–6080, *rulemaking@ntsb.gov.*

SUPPLEMENTARY INFORMATION: In light of the September 9, 2021, Executive Order (E.O.) 14043 (*Requiring Coronavirus Disease 2019 Vaccination for Federal Employees*) and October 2021 guidance from the Safer Federal Workforce Task Force, the NTSB proposes adding a new system of records to its inventory of system of records titled, ''Religious Accommodation Request Records.'' The agency proposes this new system for information from prospective, current, and former NTSB employees who request or receive accommodations for sincerely held religious beliefs, practices, or observances.

SYSTEM NAME AND NUMBER:

Religious Accommodation Request Records. NTSB–34.

SECURITY CLASSIFICATION:

Unclassified.

SYSTEM LOCATION:

Records regarding prospective and current NTSB employees are located at: National Transportation Safety Board, 490 L'Enfant Plaza SW, Washington, DC 20594. Records regarding former NTSB employees who have not transferred to another Federal agency are located at the National Personnel Records Center, National Archives and Records Administration, 111 Winnebago Street, St. Louis, Missouri 63118.

SYSTEM MANAGER:

Director, Office of Equal Employment Opportunity, Diversity and Inclusion, National Transportation Safety Board, 490 L'Enfant Plaza East SW, Washington, DC 20594.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 1302; 5 U.S.C. 301; 42 U.S.C. 2000e *et seq.;* 42 U.S.C. 2000bb *et seq.;* 44 U.S.C. 3101; 29 CFR part 1614; and E.O. 14043 (Sept. 9, 2021).

PURPOSE(S) OF THE SYSTEM:

This system of records contains information from prospective, current, and former NTSB employees who request or receive accommodations for sincerely held religious beliefs, practices, or observances. The NTSB maintains the records in this system to track and report the processing of requests for religious accommodations to comply with applicable laws and regulations and to preserve and maintain the confidentiality of religious information submitted by or on behalf of applicants or employees requesting an accommodation.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Prospective, current, and former NTSB employees who request and/or receive a reasonable accommodation for

a sincerely held religious belief, practice, or observance; and authorized individuals or representatives (*e.g.,* family members or attorneys) who file a request for a religious accommodation on behalf of a prospective, current, or former employee.

CATEGORIES OF RECORDS IN THE SYSTEM:

Name and employment information of employees needing an accommodation; requestor's name and contact information (if different than the employee who needs an accommodation); date request was initiated; information concerning the nature of the sincerely held religious belief, practice, or observance and the need for accommodation, including any appropriate documentation; details of the accommodation request, such as: type of accommodation requested, how the requested accommodation would assist in job performance, any additional information provided by the requestor related to the processing of the request, notes from or summaries of the interactive process, whether the request was approved or denied, including any alternative accommodation provided, and whether the accommodation was approved for a trial period; and notification(s) to the employee and his/her supervisor(s) regarding the accommodation.

RECORD SOURCE CATEGORIES:

The individual to whom the record pertains and/or his or her representative; NTSB supervisors and management officials; officials with the NTSB Office of Administration and Human Resources Division and Office of Equal Employment Opportunity, Diversity and Inclusion; other Federal agencies; and religious officials or organizations.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USES AND THE PURPOSES OF SUCH USES:

In addition to the disclosures permitted under subsection (b) of the Privacy Act, the NTSB may disclose information contained in this system of records without the consent of the subject individual if the disclosure is compatible with the purpose for which the record was collected under the following routine uses:

1. Disclosure to the Office of Personnel Management, Department of Labor, Merit Systems Protection Board, Office of the Special Counsel, Equal Employment Opportunity Commission, the Federal Labor Relations Authority (including the General Counsel of the Authority and the Federal Service Impasses Panel), the Federal Mediation and Conciliation Service, the White House and its executive offices, the Center for Disease Control and Prevention, the Department of Health & Human Services, Federal Occupational Health, and the National Institutes of Health, and to an arbitrator, when that agency or office has jurisdiction or oversight over religious accommodation issues, in carrying out their functions, or to obtain advice regarding statutory, regulatory, policy, or other requirements, related to a religious accommodation;

2. Disclosure to other Federal agencies that need the information for an audit or investigation of a civil, criminal, or regulatory violation or potential violation where a record, either on its face or in conjunction with other information, indicates a violation or potential violation of law;

3. Where a contract between an NTSB office and a labor organization recognized under Executive Order No. 11,491 or 5 U.S.C. Chapter 71 provides that the agency will disclose personal records relevant to the organization's mission, the NTSB may disclose records in this system of records to such organization;

4. Disclosure to a private entity with which the NTSB maintains a contractual relationship for the purposes of investigating discrimination claims, engaging in dispute resolution in connection with religious accommodations requests and/or discrimination claims, or collating, analyzing, aggregating or otherwise refining records in this system, where the private entity is subject to a non-disclosure agreement and understands that it must honor Privacy Act safeguards with respect to such records;

5. In the event of litigation where the defendant is (a) the NTSB, any component of the NTSB, or any employee of the NTSB in his or her official capacity; (b) the United States, where the NTSB determines that the claim, if successful, is likely to directly affect the operations of the NTSB or any of its components; or (c) any NTSB employee in his or her individual capacity where the Department of Justice has agreed to represent such employee, the NTSB may disclose such records as it deems relevant and necessary to the Department of Justice or NTSB's outside counsel to enable the NTSB to present an effective defense, provided such disclosure is compatible with the purpose for which the records were collected;

6. Information may be disclosed to a congressional office from the record of an individual in response to an inquiry from the congressional office made at the written request of the individual about whom the record is maintained. The NTSB will not make such a disclosure until the congressional office has furnished appropriate documentation of the individual's request, such as a copy of the individual's written request;

7. To appropriate agencies, entities, and persons when (1) the NTSB suspects or has confirmed that there has been a breach of the system of records, (2) the NTSB has determined that as a result of the suspected or confirmed breach there is a risk of harm to individuals, the NTSB (including its information systems, programs, and operations), the Federal Government, or national security; and (3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with the NTSB's efforts to respond to the suspected or confirmed breach or to prevent, minimize, or remedy such harm;

8. To another Federal agency or Federal entity, when the NTSB determines that information from this system of records is reasonably necessary to assist the recipient agency or entity in (1) responding to a suspected or confirmed breach or (2) preventing, minimizing, or remedying the risk of harm to individuals, the recipient agency or entity (including its information systems, programs, and operations), the Federal Government, or national security, resulting from a suspected or confirmed breach.

POLICIES AND PRACTICES FOR STORAGE OF RECORDS:

The NTSB maintains the records in this system on paper within file folders and electronically, including on computer databases.

POLICIES AND PRACTICES FOR RETRIEVAL OF RECORDS:

These records are indexed by employee or applicant name or the applicable NTSB office.

POLICIES AND PRACTICES FOR RETENTION AND DISPOSAL OF RECORDS:

Religious Accommodation Request Records are maintained in accordance with General Records Schedule 2.3 (April 2020).

ADMINISTRATIVE, TECHNICAL, AND PHYSICAL SAFEGUARDS:

The NTSB maintains paper records within this system in a locked file room that is restricted through electronic keycards to enter the area where records are located. Access to and use of these records is limited to those persons whose official duties require such access, and the Facility Security Access

Control System (NTSB–24) logs the date and time that each electronic keycard was used to enter the location. Electronic records are stored on protected computer networks that are accessible by authorized users with PIV cards and/or secure passwords. This system conforms to all applicable Federal laws and regulations, as well as NTSB policies and standards, as they relate to information security and data privacy. In this regard, the following laws and regulations may apply: the Privacy Act of 1974; the Federal Information Security Management Act of 2002; the Computer Fraud and Abuse Act of 1986; the E-Government Act of 2002; and corresponding regulations implementing these statutes.

RECORD ACCESS PROCEDURE:

Same as ''Notification Procedure.''

CONTESTING RECORD PROCEDURE:

Same as ''Notification Procedure.''

NOTIFICATION PROCEDURES:

Individuals wishing to inquire about whether this system of records contains information about them may contact the Chief, Records Management Division, National Transportation Safety Board, 490 L'Enfant Plaza East SW, Washington, DC 20594. Individuals must comply with NTSB regulations regarding the Privacy Act, at 49 CFR part 802, and must furnish the following information for their records to be located and identified:

1. Full name(s);
2. Dates of employment, NTSB service, or application; and
3. Signature.

EXEMPTIONS PROMULGATED FOR THE SYSTEM:

None.

HISTORY:

None.

Jennifer Homendy,

Chair.

[FR Doc. 2021–24767 Filed 11–12–21; 8:45 am]

BILLING CODE 7533–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2021–0001]

Sunshine Act Meetings

TIME AND DATE: Weeks of November 15, 22, 29, December 6, 13, 20, 2021.

PLACE: Commissioners' Conference Room, 11555 Rockville Pike, Rockville, Maryland.

STATUS: Public.

MATTERS TO BE CONSIDERED:

Week of November 15, 2021

There are no meetings scheduled for the week of November 15, 2021.

Week of November 22, 2021—Tentative

There are no meetings scheduled for the week of November 22, 2021.

Week of November 29, 2021—Tentative

There are no meetings scheduled for the week of November 29, 2021.

Week of December 6, 2021—Tentative

Tuesday, December 7, 2021

10:00 a.m. Briefing on Equal Employment Opportunity, Affirmative Employment, and Small Business (Public Meeting); (Contact: Larniece McKoy Moore: 301–415–1942)

Additional Information: The public is invited to attend the Commission's meeting live by webcast at the Web address—*https://video.nrc.gov/*. For those who would like to attend in person, note that all visitors are required to complete the NRC Self-Health Assessment and Certification of Vaccination forms. Visitors who certify that they are not fully vaccinated or decline to complete the certification must have proof of a negative Food and Drug Administration-approved PCR or Antigen (including rapid tests) COVID–19 test specimen collection from no later than the previous 3 days prior to entry to an NRC facility. The forms and additional information can be found here *https://www.nrc.gov/about-nrc/covid-19/guidance-for-visitors-to-nrc-facilities.pdf.*

Thursday, December 9, 2021

9:00 a.m. Briefing on 10 CFR part 53 Licensing and Regulations of Advanced Nuclear Reactors (Public Meeting); (Contact: Caty Nolan: 301–415–1535)

Additional Information: The public is invited to attend the Commission's meeting live by webcast at the Web address—*https://video.nrc.gov/*. For those who would like to attend in person, note that all visitors are required to complete the NRC Self-Health Assessment and Certification of Vaccination forms. Visitors who certify that they are not fully vaccinated or decline to complete the certification must have proof of a negative Food and Drug Administration-approved PCR or Antigen (including rapid tests) COVID–19 test specimen collection from no later than the previous 3 days prior to entry to an NRC facility. The forms and additional information can be found here *https://www.nrc.gov/about-nrc/covid-19/guidance-for-visitors-to-nrc-facilities.pdf.*

Week of December 13, 2021—Tentative

There are no meetings scheduled for the week of December 13, 2021.

Week of December 20, 2021—Tentative

There are no meetings scheduled for the week of December 20, 2021.

CONTACT PERSON FOR MORE INFORMATION: For more information or to verify the status of meetings, contact Wesley Held at 301–287–3591 or via email at *Wesley.Held@nrc.gov.* The schedule for Commission meetings is subject to change on short notice.

The NRC Commission Meeting Schedule can be found on the internet at: *https://www.nrc.gov/public-involve/public-meetings/schedule.html.*

The NRC provides reasonable accommodation to individuals with disabilities where appropriate. If you need a reasonable accommodation to participate in these public meetings or need this meeting notice or the transcript or other information from the public meetings in another format (*e.g.,* Braille, large print), please notify Anne Silk, NRC Disability Program Specialist, at 301–287–0745, by videophone at 240–428–3217, or by email at *Anne.Silk@nrc.gov.* Determinations on requests for reasonable accommodation will be made on a case-by-case basis.

Members of the public may request to receive this information electronically. If you would like to be added to the distribution, please contact the Nuclear Regulatory Commission, Office of the Secretary, Washington, DC 20555, at 301–415–1969, or by email at *Tyesha.Bush@nrc.gov* or *Betty.Thweatt@nrc.gov.*

The NRC is holding the meetings under the authority of the Government in the Sunshine Act, 5 U.S.C. 552b.

Dated: November 10, 2021.

For the Nuclear Regulatory Commission.

Wesley W. Held,

Policy Coordinator, Office of the Secretary.

[FR Doc. 2021–25008 Filed 11–10–21; 4:15 pm]

BILLING CODE 7590–01–P

POSTAL REGULATORY COMMISSION

[Docket No. CP2022–20]

New Postal Product

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: The Commission is noticing a recent Postal Service filing for the Commission's consideration concerning a negotiated service agreement. This

notice informs the public of the filing, invites public comment, and takes other administrative steps.

DATES: *Comments are due:* November 16, 2021.

ADDRESSES: Submit comments electronically via the Commission's Filing Online system at *http://www.prc.gov.* Those who cannot submit comments electronically should contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section by telephone for advice on filing alternatives.

FOR FURTHER INFORMATION CONTACT: David A. Trissell, General Counsel, at 202–789–6820.

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Introduction
II. Docketed Proceeding(s)

I. Introduction

The Commission gives notice that the Postal Service filed request(s) for the Commission to consider matters related to negotiated service agreement(s). The request(s) may propose the addition or removal of a negotiated service agreement from the market dominant or the competitive product list, or the modification of an existing product currently appearing on the market dominant or the competitive product list.

Section II identifies the docket number(s) associated with each Postal Service request, the title of each Postal Service request, the request's acceptance date, and the authority cited by the Postal Service for each request. For each request, the Commission appoints an officer of the Commission to represent the interests of the general public in the proceeding, pursuant to 39 U.S.C. 505 (Public Representative). Section II also establishes comment deadline(s) pertaining to each request.

The public portions of the Postal Service's request(s) can be accessed via the Commission's website (*http://www.prc.gov*). Non-public portions of the Postal Service's request(s), if any, can be accessed through compliance with the requirements of 39 CFR 3011.301.[1]

The Commission invites comments on whether the Postal Service's request(s) in the captioned docket(s) are consistent with the policies of title 39. For request(s) that the Postal Service states concern market dominant product(s), applicable statutory and regulatory requirements include 39 U.S.C. 3622, 39 U.S.C. 3642, 39 CFR part 3030, and 39 CFR part 3040, subpart B. For request(s) that the Postal Service states concern competitive product(s), applicable statutory and regulatory requirements include 39 U.S.C. 3632, 39 U.S.C. 3633, 39 U.S.C. 3642, 39 CFR part 3035, and 39 CFR part 3040, subpart B. Comment deadline(s) for each request appear in section II.

II. Docketed Proceeding(s)

1. *Docket No(s):* CP2022–20; *Filing Title:* Notice of United States Postal Service of Filing a Functionally Equivalent Global Reseller Expedited Package 2 Negotiated Service Agreement and Application for Non-Public Treatment of Materials Filed Under Seal; *Filing Acceptance Date:* November 5, 2021; *Filing Authority:* 39 CFR 3035.105; *Public Representative:* Kenneth R. Moeller; *Comments Due:* November 16, 2021.

This Notice will be published in the **Federal Register**.

Erica A. Barker,

Secretary.

[FR Doc. 2021–24756 Filed 11–12–21; 8:45 am]

BILLING CODE 7710–FW–P

[1] *See* Docket No. RM2018–3, Order Adopting Final Rules Relating to Non-Public Information, June 27, 2018, Attachment A at 19–22 (Order No. 4679).

SECURITIES AND EXCHANGE COMMISSION

Sunshine Act Meetings

TIME AND DATE: 2:00 p.m. on Thursday, November 18, 2021.

PLACE: The meeting will be held via remote means and/or at the Commission's headquarters, 100 F Street NE, Washington, DC 20549.

STATUS: This meeting will be closed to the public.

MATTERS TO BE CONSIDERED: Commissioners, Counsel to the Commissioners, the Secretary to the Commission, and recording secretaries will attend the closed meeting. Certain staff members who have an interest in the matters also may be present.

In the event that the time, date, or location of this meeting changes, an announcement of the change, along with the new time, date, and/or place of the meeting will be posted on the Commission's website at *https://www.sec.gov.*

The General Counsel of the Commission, or his designee, has certified that, in his opinion, one or more of the exemptions set forth in 5 U.S.C. 552b(c)(3), (5), (6), (7), (8), 9(B) and (10) and 17 CFR 200.402(a)(3), (a)(5), (a)(6), (a)(7), (a)(8), (a)(9)(ii) and (a)(10), permit consideration of the scheduled matters at the closed meeting.

The subject matter of the closed meeting will consist of the following topics: Institution and settlement of injunctive actions;

Institution and settlement of administrative proceedings;

Resolution of litigation claims; and

Other matters relating to examinations and enforcement proceedings.

At times, changes in Commission priorities require alterations in the scheduling of meeting agenda items that may consist of adjudicatory, examination, litigation, or regulatory matters.

CONTACT PERSON FOR MORE INFORMATION: For further information; please contact Vanessa A. Countryman from the Office of the Secretary at (202) 551–5400.

Authority: 5 U.S.C. 552b.

Dated: November 10, 2021.

Vanessa A. Countryman,

Secretary.

[FR Doc. 2021–24967 Filed 11–10–21; 4:15 pm]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[SEC File No. 270–638; OMB Control No. 3235–0687]

Proposed Collection; Comment Request

Upon Written Request Copies Available From: Securities and Exchange Commission, Office of FOIA Services, 100 F Street NE, Washington, DC 20549–2736

Extension:
Rule 239

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') is soliciting comments on the collection of information summarized below. The Commission plans to submit this existing collection of information to the Office of Management and Budget for extension and approval.

Rule 239 (17 CFR 230.239) provides exemptions under the Securities Act of 1933 (15 U.S.C. 77a *et seq.*), the Securities Exchange Act of 1934 (15 U.S.C. 78a *et seq.*) and the Trust Indenture Act of 1939 (U.S.C. 77aaa *et seq.*) for security-based swaps issued by certain clearing agencies satisfying certain conditions. The purpose of the information required by Rule 239 is to make certain information about security-based swaps that may be

cleared by the registered or the exempt clearing agencies available to eligible contract participants and other market participants. We estimate that each registered or exempt clearing agency issuing security-based swaps in its function as a central counterparty will spend approximately 2 hours each time it provides or update the information in its agreements relating to security-based swaps or on its website. We estimate that each registered or exempt clearing agency will provide or update the information approximately 20 times per year. In addition, we estimate that 75% of the 2 hours per response (1.5 hours) is prepared internally by the clearing agency for a total annual reporting burden of 180 hours (1.5 hours per response × 20 × 6 respondents).

Written comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of the burden imposed by the collection of information; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology. Consideration will be given to comments and suggestions submitted in writing within 60 days of this publication.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid control number.

Please direct your written comment to David Bottom, Director/Chief Information Officer, Securities and Exchange Commission, c/o John Pezzullo, 100 F Street NE, Washington, DC 20549 or send an email to: *PRA_Mailbox@sec.gov.*

Dated: November 9, 2021.

J. Matthew DeLesDernier,

Assistant Secretary.

[FR Doc. 2021–24882 Filed 11–12–21; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–93534; File No. SR–NYSEArca–2021–53]

Self-Regulatory Organizations; NYSE Arca, Inc.; Order Instituting Proceedings To Determine Whether To Approve or Disapprove a Proposed Rule Change To List and Trade Shares of the Teucrium Bitcoin Futures Fund Under NYSE Arca Rule 8.200–E, Commentary .02 (Trust Issued Receipts)

November 8, 2021.

On July 23, 2021, NYSE Arca, Inc. (''NYSE Arca'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1] and Rule 19b–4 thereunder,[2] a proposed rule change to list and trade shares (''Shares'') of the Teucrium Bitcoin Futures Fund (''Fund'') under NYSE Arca Rule 8.200–E, Commentary .02 (Trust Issued Receipts). The proposed rule change was published for comment in the **Federal Register** on August 11, 2021.[3]

On September 15, 2021, pursuant to Section 19(b)(2) of the Act,[4] the Commission designated a longer period within which to approve the proposed rule change, disapprove the proposed rule change, or institute proceedings to determine whether to disapprove the proposed rule change.[5] This order institutes proceedings under Section 19(b)(2)(B) of the Act [6] to determine whether to approve or disapprove the proposed rule change.

I. Summary of the Proposal

As described in more detail in the Notice,[7] the Exchange proposes to list and trade the Shares of the Fund under NYSE Arca Rule 8.200–E, Commentary .02, which governs the listing and trading of Trust Issued Receipts on the Exchange.

According to the Exchange, the Chicago Mercantile Exchange, Inc. (''CME'') currently offers two bitcoin futures contracts, one contract representing five (5) bitcoin (''BTC Contracts'') and another contract representing one-tenth of one (0.10) bitcoin (''MBT Contracts'').[8] Each BTC Contract and MBT Contract settles daily to the BTC Contract volume-weighted average price (''VWAP'') of all trades that occur between 2:59 p.m. and 3:00 p.m., Central Time, the settlement period, rounded to the nearest tradable tick.[9] BTC Contracts and MBT Contracts each expire on the last Friday of the contract month and the final settlement value for each contract is based on the CME CF Bitcoin Reference Rate (''CME CF BRR'').[10]

The investment objective of the Fund is to have the daily changes in the net asset value (''NAV'') of the Shares reflect the daily changes in the price of a specified benchmark (''Benchmark'').[11] The Benchmark is the average of the closing settlement prices for the first to expire and second to expire BTC Contracts listed on the CME. In seeking to achieve the Fund's investment objective, the Sponsor will employ a ''neutral'' investment strategy that is intended to track the changes in the Benchmark. Under normal market conditions, the Fund will invest in the first to expire and second to expire BTC Contracts and MBT Contracts (''Bitcoin Futures Contracts'') and in cash and cash equivalents. The Fund will roll its futures positions on a regular basis in order to track the changing nature of the Benchmark by closing out first to expire contracts prior to settlement that are no longer part of the Benchmark and then entering into second to expire contracts. Accordingly, the Fund will never carry futures positions all the way to cash settlement. The Fund will endeavor to trade in Bitcoin Futures Contracts so that the Fund's average daily tracking error against the Benchmark will be less than 10 percent over any period of 30 trading days.[12]

The net asset value (''NAV'') per Share of the Fund will be calculated by taking the current market value of its

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 92573 (Aug. 5, 2021), 86 FR 44062 (Aug. 11, 2021) (''Notice''). Comments on the proposed rule change can be found at: *https://www.sec.gov/comments/sr-nysearca-2021-53/srnysearca202153.htm.*

[4] 15 U.S.C. 78s(b)(2).

[5] *See* Securities Exchange Act Release No. 92999, 86 FR 52539 (Sept. 21, 2021). The Commission designated November 9, 2021, as the date by which it should approve, disapprove, or institute proceedings to determine whether to disapprove the proposed rule change.

[6] 15 U.S.C. 78s(b)(2)(B).

[7] *See* Notice, *supra* note 3.

[8] BTC Contracts began trading on the CME Globex trading platform on December 15, 2017 and are cash-settled in U.S. dollars. MBT Contracts began trading on the CME Globex trading platform on May 3, 2021 under the ticker symbol ''MBT'' and are also cash-settled in U.S. dollars. *See id.* at 44062.

[9] *See id.* at. 44073.

[10] *See id.* The CME CF BRR aggregates the trade flow of major bitcoin spot exchanges during a specific calculation window into a once-a-day reference rate of the U.S. dollar price of bitcoin. *See id.* at 44067 n.59.

[11] The Fund is a series of Teucrium Commodity Trust (''Trust''). The Fund is managed and controlled by Teucrium Trading, LLC (''Sponsor''). *See id.* at 44062.

[12] *See id.* at 44062–63.

total assets, subtracting any liabilities, and dividing that total by the number of Shares. The administrator of the Fund will calculate the NAV once each trading day, as of the earlier of the close of the New York Stock Exchange or 4:00 p.m., Eastern Standard Time. To determine the value of Bitcoin Futures Contracts, the Fund's administrator will use the Bitcoin Futures Contract settlement price on the exchange on which the contract is traded, except that the ''fair value'' of Bitcoin Futures Contracts may be used when Bitcoin Futures Contracts close at their price fluctuation limit for the day. The Fund's NAV will include any unrealized profit or loss on open Bitcoin Futures Contracts and any other credit or debit accruing to the Fund but unpaid or not received by the Fund.[13]

The daily holdings of the Fund will be available on the Fund's website. ICE Data Indices, LLC will calculate an updated Indicative Fund Value (''IFV'') for the Fund, which will be disseminated on a per Share basis every 15 seconds during the Exchange's Core Trading Session. The IFV will be calculated by using the prior day's closing NAV per Share of the Fund as a base and will be updated throughout the Exchange's Core Trading Session to reflect changes in the value of the Fund's holdings during the trading day. The intraday, closing prices, and settlement prices of the Bitcoin Futures Contracts, as well as their specific contract specifications, will be readily available from the applicable futures exchange websites, automated quotation systems, published or other public sources, or major market data vendors. Intra-day price and closing price level information for the Benchmark will be available from major market data vendors. The Benchmark value will be disseminated once every 15 seconds.[14]

The Fund would create and redeem Shares from time to time, but only in one or more blocks of 12,500 Shares (''Creation Baskets''). The purchase and redemption price for Creation Baskets would be the NAV calculated at the end of the business day when a request for a purchase or redemption is received by the Fund. By placing a purchase order, an authorized purchaser would agree to deposit cash with the custodian.[15] The redemption distribution from the Fund would consist of an amount of cash, cash equivalents and/or exchange listed bitcoin futures that is in the same proportion to the total assets of the Fund on the date that the order to redeem is properly received as the number of Shares to be redeemed under the redemption order is in proportion to the total number of Shares outstanding on the date the order is received.[16]

II. Proceedings To Determine Whether To Approve or Disapprove SR–NYSEArca–2021–53 and Grounds for Disapproval Under Consideration

The Commission is instituting proceedings pursuant to Section 19(b)(2)(B) of the Act[17] to determine whether the proposed rule change should be approved or disapproved. Institution of proceedings is appropriate at this time in view of the legal and policy issues raised by the proposed rule change, as discussed below. Institution of proceedings does not indicate that the Commission has reached any conclusions with respect to any of the issues involved. Rather, as described below, the Commission seeks and encourages interested persons to provide comments on the proposed rule change.

Pursuant to Section 19(b)(2)(B) of the Act,[18] the Commission is providing notice of the grounds for disapproval under consideration. The Commission is instituting proceedings to allow for additional analysis of the proposed rule change's consistency with Section 6(b)(5) of the Act, which requires, among other things, that the rules of a national securities exchange be ''designed to prevent fraudulent and manipulative acts and practices'' and ''to protect investors and the public interest.''[19]

The Commission asks that commenters address the sufficiency of the Exchange's statements in support of the proposal, which are set forth in the Notice,[20] in addition to any other comments they may wish to submit about the proposed rule change. In particular, the Commission seeks comment on the following questions and asks commenters to submit data where appropriate to support their views:

1. What are commenters' views on whether the proposed Fund and Shares would be susceptible to manipulation? What are commenters' views generally on whether the Exchange's proposal is designed to prevent fraudulent and manipulative acts and practices?

2. What are commenters' views of the Exchange's assertions that the regulatory and financial landscape relating to bitcoin and other digital assets have changed significantly since 2016?[21] Are the changes that the Exchange identifies sufficient to support the determination that the proposal to list and trade the Shares is designed to protect investors and the public interest and is consistent with the other applicable requirements of Section 6(b)(5) of the Act?

3. The Exchange states that the Fund would provide ''an opportunity for U.S. investors to gain price exposure to Bitcoin futures contracts in a regulated and transparent exchange-traded vehicle that limits risks'' and asserts that concerns regarding potential manipulation of a bitcoin exchange-traded product ''have been sufficiently mitigated by the use of futures contracts in the proposed ETP.''[22] What are commenters' views regarding such assertions?

4. According to the Exchange, ''trading in CME Bitcoin futures contracts has increased significantly, in particular with respect to BTC Contracts,'' and ''[n]early every measurable metric related to BTC Contracts has trended consistently up since launch and/or accelerated upward in the past year.''[23] The Exchange also states that it believes the data provided regarding the recent growth in the bitcoin futures market ''clearly establishes that the CME Bitcoin futures markets generally are a market of significant size'' and ''the current size and volume of the CME Bitcoin futures market is already more than adequate—and still growing in size—to make its own trading activity the primary, if not the lone determinant, of its valuation.''[24] Based on information provided by the Exchange, do commenters agree with the Exchange that the CME's bitcoin futures market now represents a regulated market of significant size?[25]

5. The Exchange states it believes that ''the surveillance agreement already in place between the Exchange and the

[13] *See id.* at 44073–74.

[14] *See id.* at 44074–75.

[15] An authorized purchaser who places a purchase order would transfer to the custodian the required amount of cash, cash equivalents and/or bitcoin futures by the end of the next business day following the purchase order date or by the end of such later business day, not to exceed three business days after the purchase order date, as agreed to between the authorized purchaser and the custodian when the purchase order is placed (''Purchase Settlement Date''). Upon receipt of the deposit amount, the custodian would direct DTC to credit the number of Creation Baskets ordered to the authorized purchaser's DTC account on the Purchase Settlement Date. *See id.*

[16] *See id.*

[17] 15 U.S.C. 78s(b)(2)(B).

[18] *Id.*

[19] 15 U.S.C. 78f(b)(5).

[20] *See* Notice, *supra* note 3.

[21] *See id.* at 44063–66.

[22] *See id.* at 44066.

[23] *See id.* at 44067.

[24] *See id.* at 44072.

[25] *See id.* at 44071.

CME is 'adequate to monitor' for abuses in the trading of the Fund's shares, given the significant likelihood that a person attempting to manipulate the price of the shares of the Fund would have to manipulate the prices of the Bitcoin Futures Contracts.'' [26] The Exchange also states that ''any would-be manipulator of Bitcoin prices would be reasonably likely to have to do so through the CME Bitcoin futures market. . . .'' [27] Do commenters agree with the Exchange's assertions? Why or why not?

6. The Exchange states it believes that ''trading in the Shares would not be the predominant force on prices in the Bitcoin Futures market'' because of ''the significant volume in and size of the CME Bitcoin futures market and the significant liquidity available in the spot market.'' [28] What are commenters views on the Exchange's assertion and the data provided by the Exchange to support such assertion?

7. The Exchange states ''due to the unique structure of the Fund, it is unlikely that price manipulation or fraud on the trading platforms for Bitcoin will have a measurable impact on the NAV of the Fund.'' [29] The Exchange further states ''[b]ecause the Fund calculates daily NAV based on Bitcoin Futures Contracts' settlement prices and does not calculate NAV based directly on the underlying spot Bitcoin market, the Sponsor believes that the only practicable way for a bad actor to manipulate the NAV of the Fund is through manipulating the first and second to expire Bitcoin Futures Contracts.'' [30] In addition, the Exchange states ''BTC Contracts and MBT Contracts are now of such size and scale that Bitcoin futures prices are not specifically materially influenced by other Bitcoin markets.'' [31] What are commenters' views on these assertions?

8. The Sponsor believes that similarities between the operational characteristics and regulatory requirements applicable to exchange-traded funds (''ETFs'') that both register the sale of their shares under the Securities Act of 1933 (''1933 Act'') and are regulated under the Investment Company Act of 1940 (''1940 Act'') and bitcoin futures-based ETPs that register the sale of their shares under the 1933 Act but are not regulated under the 1940 Act like the Fund ''provide sufficient investor protections'' and that ''there are no investor protections afforded by the 1940 Act that justify unequal review and approval processes for [the Fund] as opposed to bitcoin ETFs.'' [32] The Sponsor further states that ''in addition to ETFs being required to have a board where ETPs are not, ETFs are also subject to a number of substantive limitations under the 1940 Act to which ETPs are not—*e.g.,* limitations on transactions with affiliates and on leverage'' but that it ''does not believe [the Fund's] proposed structure or operations differ substantively from bitcoin ETFs in any manner that should lead the Commission to require 1940 Act registration.'' [33] What are commenters' views of such assertions?

9. The Exchange states that ''the Commission should also consider the direct, quantifiable investor protection issue in determining whether to approve this proposal.'' [34] In addition, the Exchange states that exposure to bitcoin through a bitcoin futures-based ETP like the Fund presents advantages to retail investors compared to buying spot bitcoin, investing in OTC bitcoin funds, or investing in operating companies with bitcoin exposure.[35] What are commenters' views regarding the Exchange's assertions?

III. Procedure: Request for Written Comments

The Commission requests that interested persons provide written submissions of their views, data, and arguments with respect to the issues identified above, as well as any other concerns they may have with the proposal. In particular, the Commission invites the written views of interested persons concerning whether the proposal is consistent with Section 6(b)(5) or any other provision of the Act, and the rules and regulations thereunder. Although there do not appear to be any issues relevant to approval or disapproval that would be facilitated by an oral presentation of views, data, and arguments, the Commission will consider, pursuant to Rule 19b–4, any request for an opportunity to make an oral presentation.[36]

Interested persons are invited to submit written data, views, and arguments regarding whether the proposal should be approved or disapproved by December 6, 2021. Any person who wishes to file a rebuttal to any other person's submission must file that rebuttal by December 20, 2021.

Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–NYSEArca–2021–53 on the subject line.

Paper Comments

- Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE, Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEArca–2021–53. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's internet website (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for website viewing and printing in the Commission's Public Reference Room, 100 F Street NE, Washington, DC 20549 on official business days between the hours of 10:00 a.m. and 3:00 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change. Persons submitting comments are cautioned that we do not redact or edit

[26] *See id.* at 44072

[27] *See id.*

[28] *See id.* at 44073. For example, the Exchange states that one Creation Unit (12,500 Shares) at $50 per share and CME contract value of $200,000 only prompts buying of a little over 3 contracts; 10 Creation Units = 31 contracts; 100 Creation Units = 310 contracts, compared to YTD average daily trade volume of 8800 first to expire and 2450 second to expire contracts. *See id.* at 44073 n. 87

[29] *See id.* at 44071.

[30] *See id.*

[31] *See id.*

[32] *See* Letter from W. Thomas Conner, Vedder Price, on behalf of the Sponsor, dated September 1, 2021, at 6, available at *https://www.sec.gov/comments/sr-nysearca-2021-53/srnysearca202153-9197848-249688.pdf.*

[33] *See id.* at 9.

[34] *See* Notice, *supra* note 3, at 44067.

[35] *See id.* at 44066–67.

[36] Section 19(b)(2) of the Act, as amended by the Securities Act Amendments of 1975, Public Law 94–29 (June 4, 1975), grants the Commission flexibility to determine what type of proceeding—either oral or notice and opportunity for written comments—is appropriate for consideration of a particular proposal by a self-regulatory organization. *See* Securities Act Amendments of 1975, Senate Comm. on Banking, Housing & Urban Affairs, S. Rep. No. 75, 94th Cong., 1st Sess. 30 (1975).

personal identifying information from comment submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEArca–2021–53 and should be submitted by December 6, 2021. Rebuttal comments should be submitted by December 20, 2021.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[37]

J. Matthew DeLesDernier,

Assistant Secretary.

[FR Doc. 2021–24764 Filed 11–12–21; 8:45 am]

BILLING CODE 8011–01–P

[37] 17 CFR 200.30–3(a)(57).

DEPARTMENT OF STATE

[Public Notice 11585]

30-Day Notice of Proposed Information Collection: Petition To Classify Special Immigrant Under INA 203(b)(4) as Employee or Former Employee of the U.S. Government Abroad

ACTION: Notice of request for public comment and submission to OMB of proposed collection of information.

SUMMARY: The Department of State has submitted the information collection described below to the Office of Management and Budget (OMB) for approval. In accordance with the Paperwork Reduction Act of 1995 we are requesting comments on this collection from all interested individuals and organizations. The purpose of this Notice is to allow 30 days for public comment.

DATES: Submit comments up to December 15, 2021.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

FOR FURTHER INFORMATION CONTACT: Direct requests for additional information regarding the collection listed in this notice, including requests for copies of the proposed collection instrument and supporting documents, to Andrea Lage, Acting Regulatory Coordinator, Visa Services, who may be reached on *PRA_BurdenComments@state.gov* or (202) 485–7586.

SUPPLEMENTARY INFORMATION:

- *Title of Information Collection:* Petition to Classify Special Immigrant Under INA 203(b)(4) as Employee or Former Employee of the U.S. Government Abroad.
- *OMB Control Number:* 1405–0082.
- *Type of Request:* Extension of a Currently Approved Collection.
- *Originating Office:* CA/VO.
- *Form Number:* DS–1884.
- *Respondents:* Aliens petitioning for immigrant visas under INA 203(b)(4) as a special immigrant described in INA section 101(a)(27)(D).
- *Estimated Number of Respondents:* 600.
- *Estimated Number of Responses:* 600.
- *Average Time Per Response:* 10 minutes.
- *Total Estimated Burden Time:* 100 hours.
- *Frequency:* Once per petition.
- *Obligation to Respond:* Required to Obtain or Retain a Benefit.

We are soliciting public comments to permit the Department to:

- Evaluate whether the proposed information collection is necessary for the proper functions of the Department.
- Evaluate the accuracy of our estimate of the time and cost burden for this proposed collection, including the validity of the methodology and assumptions used.
- Enhance the quality, utility, and clarity of the information to be collected.
- Minimize the reporting burden on those who are to respond, including the use of automated collection techniques or other forms of information technology.

Please note that comments submitted in response to this Notice are public record. Before including any detailed personal information, you should be aware that your comments as submitted, including your personal information, will be available for public review.

Abstract of Proposed Collection

DS–1884 solicits information from petitioners claiming employment-based immigrant visa preference under section 203(b)(4) of the Immigration and Nationality Act on the basis of qualification as a special immigrant described in section 101(a)(27)(D) of the Immigration and Nationality Act. A petitioner may file the DS–1884 petition within one year of notification by the Department of State that the Secretary has approved a recommendation for special immigrant status. DS–1884 solicits information that will assist the consular officer in ensuring that the petitioner is statutorily qualified to receive such status, including meeting the years of service and exceptional service requirements.

Methodology

The petitioner can obtain the form from consular posts abroad or through the Department's website, *travel.state.gov.* The application available on the Department's website allows an applicant to complete the application electronically and then print the application and submit it to post.

Kevin E. Bryant,

Deputy Director, Office of Directives Management, Department of State.

[FR Doc. 2021–24811 Filed 11–12–21; 8:45 am]

BILLING CODE 4710–06–P

DEPARTMENT OF STATE

[Public Notice 11583]

Advisory Committee on International Law

ACTION: Notice of Open Meeting.

Notice of Meeting of Advisory Committee on International Law.

A meeting of the Department of State's Advisory Committee on International Law will take place virtually on Friday, December 3, 2021. Acting Legal Adviser Richard Visek will chair the meeting, which will be open to the public. It is anticipated that the meeting will include discussions on current international law topics of key importance to the Office of the Legal Adviser.

Members of the public who wish to attend should contact the Office of the Legal Adviser by December 1 at *welcherar@state.gov* or 202–647–1646 and provide their name, professional affiliation, address, and phone number. A link to the virtual meeting platform will be provided at that time. Attendees who require reasonable accommodation should make their requests by November 26. Requests received after that date will be considered but might not be possible to accommodate.

Alison Welcher,

Executive Director, Advisory Committee on International Law, Department of State.

[FR Doc. 2021–24761 Filed 11–12–21; 8:45 am]

BILLING CODE 4710–08–P

DEPARTMENT OF STATE

[Public Notice: 11582]

International Digital Economy and Telecommunication (IDET) Advisory Committee Solicitation of Applications for Membership

ACTION: Notice.

SUMMARY: The Acting Deputy Assistant Secretary of State for International Communications and Information Policy, in the Bureau of Economic and Business Affairs, is accepting applications for membership on the International Digital Economy and Telecommunication (IDET) Advisory Committee, formerly known as the International Telecommunication Advisory Committee (ITAC).

DATES: Applications should be sent by email to *IDET@state.gov* by close of business on December 8, 2021.

SUPPLEMENTARY INFORMATION: The purpose of the IDET is to advise the Department of State with respect to, and provide strategic planning recommendations on, digital economy, digital connectivity, economic aspects of emerging digital technologies, telecommunications, and communication and information policy matters, including those related to the U.S. participation in the work of the International Telecommunication Union (ITU), the Organization of American States Inter-American Telecommunication Commission (CITEL), the Organization for Economic Cooperation and Development (OECD), the Asia Pacific Economic Cooperation (APEC) Forum Telecommunications and Information Working Group, the Group of Seven (G7), the Group of Twenty (G20) Digital Economy Task Force, and relevant standards setting bodies. Its Charter is accessible here: *https://www.state.gov/international-digital-economy-and-telecommunication-advisory-committee/.*

Qualifications and Membership: IDET Members are appointed by the Deputy Assistant Secretary and must be U.S. citizens or legal permanent residents of the United States. The IDET charter calls for representative members; therefore, a prospective member must represent a company or organization. Solo members (*i.e.,* who ''represent themselves'') will not be selected. To ensure diversity in advice, IDET membership will include not more than one representative from any affiliated agency or organization so long as the threshold of no fewer than 20 members is met. IDET members must be versed in the complexity of international communications and information policy issues and must be able to advise the Department of State on these matters. Members are expected to use their expertise and provide candid advice. Please note that IDET members will not be reimbursed for travel, per diem, nor other expenses incurred in connection with their duties as IDET members.

How to Apply: Applicants should email applications in response to this notice to *IDET@state.gov.* Applications must contain the following information: (1) Name of applicant; (2) citizenship of the applicant or residency status; (3) organizational affiliation and title; (4) mailing address; (5) work telephone number; (6) email address; (7) résumé; (8) brief statement of interest for IDET membership of no more than 300 words; and (9) confirmation that your organization or company expects you to represent their interests. The Department will identify suitable candidates with a view to maintaining membership balance and diversity of viewpoint, with advice, as necessary, from the Federal Communication Commission (FCC) and National Telecommunication and Information Administration (NTIA).

FOR FURTHER INFORMATION CONTACT: Please contact the Designated Federal Officer (DFO) Daniel Oates or Brian Mattys at *IDET@state.gov,* or (202) 878–2010.

Adam W. Lusin,

Director, Multilateral Affairs, International Communications and Information Policy, U.S. State Department.

[FR Doc. 2021–24816 Filed 11–12–21; 8:45 am]

BILLING CODE 4710–AE–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Notice of Final Federal Agency Actions on Proposed Transportation Project in Florida

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice of limitation on claims for judicial review of actions by Florida Department of Transportation (FDOT), pursuant to 23 U.S.C. 327, and other Federal Agencies.

SUMMARY: The FHWA, on behalf of the FDOT, is issuing this notice to announce actions taken by FDOT and other Federal Agencies that are final agency actions. These actions relate to the proposed SR–9/I–95 from south of SW 10th Street to north of Hillsboro Boulevard Project Development and Environment (PD&E) Study (Financial Management Number 436964–1–22–01). The proposed improvements include direct connect ramps from SW 10th Street to I–95 general use and express lanes. Operational improvements at the SW 10th Street and Hillsboro Boulevard ramp terminal intersections, are also included in the project. These actions grant licenses, permits, or approvals for the project.

DATES: By this notice, the FHWA, on behalf of FDOT, is advising the public of final agency actions subject to 23 U.S.C. 139(l)(1). A claim seeking judicial review of the Federal Agency actions on the listed highway project will be barred unless the claim is filed on or before April 14, 2022. If the Federal law that authorizes judicial review of a claim provides a time period of less than 150 days for filing such claim, then that shorter time period still applies.

FOR FURTHER INFORMATION CONTACT: For FDOT: Jennifer Marshall, P.E., Director, Office of Environmental Management, FDOT, 605 Suwannee Street, MS 37, Tallahassee, Florida 32399; telephone (850) 414–3100; email: *Jennifer.Marshall@dot.state.fl.us.* The FDOT Office of Environmental Management's normal business hours are 8:00 a.m. to 5:00 p.m. (Eastern Standard Time), Monday through Friday, except State holidays.

SUPPLEMENTARY INFORMATION: Effective December 14, 2016, the FHWA assigned, and the FDOT assumed, environmental responsibilities for this project pursuant to 23 U.S.C. 327. Notice is hereby given that FDOT and other Federal Agencies have taken final agency actions subject to 23 U.S.C. 139(l)(1) by issuing licenses, permits, or approvals for the proposed highway project. The actions by FDOT and other Federal Agencies on the project, and the laws under which such actions were taken are described in the Type 2 Categorical Exclusion issued on October 1, 2021 and in other project records for the listed project. The Type 2 Categorical Exclusion and other documents for the listed project are available by contacting FDOT at the address provided above. The Type 2 Categorical Exclusion and additional project documents can be viewed and downloaded from the project website at: *www.fdot.gov/projects/sr9/index.html.* The project subject to this notice is:

Project Location: Broward County, Florida, SR–9/I–95 PD&E Study in the City of Deerfield Beach, SR9/I–95 from south of SW 10th Street to north of Hillsboro Boulevard and the ramp terminal intersections at the SW 10th Street and Hillsboro Boulevard interchanges.

Project Actions: This notice applies to the Type 2 Categorical Exclusion, and all laws under which such actions were taken, including but not limited to:

1. *General:* National Environmental Policy Act (NEPA) [42 U.S.C. 4321 *et seq.*]; Federal–Aid Highway Act (FAHA) [23 U.S.C. 109 and 23 U.S.C. 128]; 23 CFR part 771.

2. *Air:* Clean Air Act (CAA) [42 U.S.C. 7401–7671(q)], with the exception of project level conformity determinations [42 U.S.C. 7506].

3. *Noise:* Noise Control Act of 1972 [42 U.S.C. 4901–4918]; 23 CFR part 772.

4. *Land:* Section 4(f) of the Department of Transportation Act of 1966 [23 U.S.C. 138 and 49 U.S.C. 303]; 23 CFR part 774; Land and Water Conservation Fund (LWCF) [54 U.S.C. 200302–200310].

5. *Wildlife:* Endangered Species Act (ESA) [16 U.S.C. 1531–1544 and 1536]; Marine Mammal Protection Act [16 U.S.C. 1361–1423h], Anadromous Fish Conservation Act [16 U.S.C. 757(a)–757(f)]; Fish and Wildlife Coordination Act [16 U.S.C. 661–667(d)]; Migratory Bird Treaty Act (MBTA) [16 U.S.C. 703–712]; Magnuson-Stevenson Fishery Conservation and Management Act of 1976, as amended [16 U.S.C. 1801–1891d], with Essential Fish Habitat requirements [16 U.S.C. 1855(b)(2)].

6. *Historic and Cultural Resources:* Section 106 of the National Historic Preservation Act of 1966, as amended [54 U.S.C. 3006101 *et seq.*]; Archaeological Resources Protection Act of 1979 (ARPA) [16 U.S.C. 470(aa)–470(II)]; Preservation of Historical and Archaeological Data [54 U.S.C. 312501–312508]; Native American Grave Protection and Repatriation Act (NAGPRA) [25 U.S.C. 3001–3013; 18 U.S.C. 1170].

7. *Social and Economic:* Civil Rights Act of 1964 [42 U.S.C. 2000d—2000d–1]; American Indian Religious Freedom Act [42 U.S.C. 1996]; Farmland Protection Policy Act (FPPA) [7 U.S.C. 4201–4209].

8. *Wetlands and Water Resources:* Clean Water Act (Section 319, Section 401, Section 404) [33 U.S.C. 1251–1387]; Coastal Barriers Resources Act (CBRA) [16 U.S.C. 3501–3510]; Coastal Zone Management Act (CZMA) [16 U.S.C. 1451–1466]; Safe Drinking Water Act (SDWA) [42 U.S.C. 300f—300j–26]; Rivers and Harbors Act of 1899 [33 U.S.C. 401–406]; Wild and Scenic Rivers Act [16 U.S.C. 1271–1287]; Emergency Wetlands Resources Act [16 U.S.C. 3921, 3931]; Wetlands Mitigation, [23 U.S.C. 119(g) and 133(b)(3)]; Flood Disaster Protection Act [42 U.S.C. 4001–4130].

9. *Hazardous Materials:* Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) [42 U.S.C. 9601–9675]; Superfund Amendments and Reauthorization Act of 1986 (SARA); Resource Conservation and Recovery Act (RCRA) [42 U.S.C. 6901–6992(k)].

10. *Executive Orders:* E.O. 11990 Protection of Wetlands; E.O. 11988 Floodplain Management; E.O. 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations; E.O. 11593 Protection and Enhancement of Cultural Resources; E.O. 13007 Indian Sacred Sites; E.O. 13287 Preserve America; E.O. 11514 Protection and Enhancement of Environmental Quality; E.O. 13112 Invasive Species.

(Catalog of Federal Domestic Assistance Program Number 20.205, Highway Planning and Construction. The regulations implementing Executive Order 12372 regarding intergovernmental consultation on Federal programs and activities apply to this program.)

Authority: 23 U.S.C. 139(l)(1).

Issued on: November 5, 2021.

Karen M. Brunelle,

Director, Office of Project Development, Federal Highway Administration, Tallahassee, Florida.

[FR Doc. 2021–24622 Filed 11–12–21; 8:45 am]

BILLING CODE 4910–RY–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Notice of Final Actions for the Tier 1 Environmental Impact Statement (EIS) for the Sonoran Corridor Between Interstate 19 (I–19) and Interstate 10 (I–10), South of the Tucson International Airport in Pima County, Arizona

AGENCY: Arizona Department of Transportation (ADOT), Federal Highway Administration (FHWA).

ACTION: Notice.

SUMMARY: This notice announces actions taken by the Federal Highway Administration (FHWA) and the Arizona Department of Transportation (ADOT) that are final. The actions relate to the Tier 1 EIS study associated with the Sonoran Corridor between I–19 and I–10, south of the Tucson International Airport in Pima County, Arizona. The public is advised that FHWA issued a ROD which signifies the conclusion of the Sonoran Corridor Tier 1 EIS study. The ROD is combined with the Tier 1 Final EIS prepared by FHWA and ADOT.

DATES: By this notice, FHWA is advising the public of final agency actions subject to 23 U.S.C. 139(*l*)(1). A claim seeking judicial review of the Federal agency actions on the Sonoran Corridor Tier 1 EIS will be barred unless the claim is filed on or before April 14, 2022. If this date falls on a Saturday or Sunday, or legal holiday, parties are advised to file their claim no later than the business day preceding this date. If the Federal law that authorizes judicial review of a claim provides a time period of less than 150 days for filing such claim, then that shorter time period still applies.

ADDRESSES: The single Sonoran Corridor Tier 1 Final EIS/ROD document is now available online at: *https://azdot.gov/planning/transportation-studies/sonoran-corridor-tier-1-environmental-impact-statement.* Hard copies of the single Sonoran Corridor Tier 1 Final EIS/ROD document is also available at the following locations during normal business hours: ADOT Southcentral District Office, 1221 South 2nd Avenue, Tucson, Arizona 85713, please call (520) 388–4200 to make an appointment; Joel D. Valdez Main Library, 101 North Stone Avenue, Tucson, Arizona 85701, (520) 594–5500; Joyner-Green Valley Library, 601 North La Canada Drive, Green Valley, Arizona 85614, (520) 594–5295; and Town of Sahuarita Clerk's Office, 375 West Sahuarita Center Way, Sahuarita, Arizona 85629, (520) 822–8801.

FOR FURTHER INFORMATION CONTACT: For FHWA, contact Mr. Ammon Heier, Area Engineer, Federal Highway Administration, 4000 North Central Avenue, Suite 1500, Phoenix, Arizona 85012, Email: *ammon.heier@dot.gov,* Telephone: (602) 382–8983. Regular office hours are from 7:30 a.m. to 4:30 p.m., Monday through Friday, except for Federal holidays. For ADOT, contact Mr. Samuel Patton, Project Manager, Arizona Department of Transportation, 206 South 17th Avenue, Phoenix, Arizona 85007, Email: *spatton@azdot.gov,* Telephone: (602) 712–6168. Regular office hours are from 8:00 a.m. to 5:00 p.m., Monday through Friday, except for Federal holidays. Project information can be obtained from the project website at: *https://azdot.gov/planning/transportation-studies/sonoran-corridor-tier-1-environmental-impact-statement.*

SUPPLEMENTARY INFORMATION: FHWA and ADOT, in cooperation with the Federal Aviation Administration, U.S. Army Corps of Engineers, U.S. Bureau of Reclamation, U.S. Environmental Protection Agency, and the Arizona Game and Fish Department, prepared a

Tier 1 EIS for the Sonoran Corridor between I–19 and I–10, south of the Tucson International Airport in Pima County, Arizona in accordance with the National Environmental Policy Act (NEPA); the Council on Environmental Quality regulations implementing NEPA (40 CFR parts 1500 through 1508), FHWA's regulations implementing NEPA (23 CFR part 771), and Section 4(f) (23 CFR part 774). The Sonoran Corridor Tier 1 EIS identified *Corridor Alternative 7: El Toro South to Rita Road* as the Preferred Alternative. Subsequently, FHWA concurred with the selection of *Corridor Alternative 7: El Toro South to Rita Road* and issued a ROD for the Sonoran Corridor Tier 1 EIS study. The ROD, combined with the Tier 1 EIS pursuant to 49 U.S.C. 304a(b), 23 U.S.C. 139(n)(2), and 23 CFR 771.124, identifies and discusses all such factors that FHWA and ADOT balanced in making the decision for the Tier 1 EIS study.

Corridor Alternative 7: El Toro South to Rita Road effectively addresses transportation deficiencies that were identified in the Tier 1 EIS, and meets the overall purpose of the study, which is to identify a high priority, high-capacity, access-controlled transportation corridor that will improve the existing transportation network by affording better access to service growth areas and existing activity centers; reduce congestion and improve the Level of Service that is predicted for the study area in 2045; and provide a system linkage that improves mobility associated with regional, interstate, and international travel. *Corridor Alternative 7: El Toro South to Rita Road* is approximately 20.47 miles long and extends from the west at I–19 in Sahuarita, near El Toro Road, to I–10 at Rita Road. From I–19, it will travel east along a new alignment for approximately 2 miles, then travel north along an extension of Alvernon Way to Old Vail Connection Road, and then follow Old Vail Connection Road east to I–10 at Rita Road.

FHWA and ADOT initiated the Sonoran Corridor Tier 1 EIS study in May 2017. The Tier 1 EIS evaluated three Build corridor alternatives and the No-Build Alternative. The three Build corridor alternatives were 2000-ft corridors, in which a future specific 400-ft highway alignment would be identified, evaluated, and constructed during Tier 2 if selected. The Tier 1 EIS considered the evaluation of environmental, social, and economic effects of the Sonoran Corridor at a programmatic level. Since *Corridor Alternative 7: El Toro South to Rita Road* is identified as the Selected Alternative in the ROD issued by FHWA, future Tier 2 studies will discuss and address the site-specific details on project impacts, costs, and identify specific mitigation measures once funding to construct a highway alignment within the 2000-ft corridor area of *Corridor Alternative 7: El Toro South to Rita Road* is identified. Since *Corridor Alternative 7: El Toro South to Rita Road* is a long-term improvement that will likely be implemented in segments over time at a level of detail sufficient to move elements of the plan toward construction, a Phased Implementation Plan was included in the single Sonoran Corridor Tier 1 Final EIS/ROD document.

The actions by FHWA, ADOT, and other relevant Federal agencies and the laws under which such actions were taken, are described in the Tier 1 Draft EIS approved on October 27, 2020, the Tier 1 Final EIS/ROD approved on October 27, 2021, and in other documents in the project's file. This notice applies to all Federal agency decisions as of the issuance date of this notice and all laws under which such actions were taken, including but not limited to: National Environmental Policy Act (NEPA) [42 U.S.C. 4321 *et seq.*]; Federal-Aid Highway Act [23 U.S.C. 101 set seq]; Clean Air Act [42 U.S.C. 7401 *et seq.*]; Section 4(f) of the US Department of Transportation Act of 1966 [49 U.S.C. 303, 23 U.S.C. 138]; Endangered Species Act [16 U.S.C. 1531–1544, 1536]; Migratory Bird Treaty Act [16 U.S.C. 703–712]; The National Historic Preservation Act of 1966, [54 U.S.C. 300101 *et seq.*]; Archeological Resources Protection Act [16 U.S.C. 16 U.S.C. 470aa–mm]; Archeological and Historic Preservation Act [16 U.S.C. 469]; Native American Grave Protection and Repatriation Act (NAGPRA) [25 U.S.C. 3001–3013]; Title VI of Civil Rights Act [42 U.S.C. 2000d *et seq.*]; American Indian Religious Freedom Act [42 U.S.C. 1996]; Farmland Protection Policy Act (FPPA) [7 U.S.C. 4201 *et seq.*]; Clean Water Act [33 U.S.C. 1251 *et seq.*]; E.O. 11990 Protection of Wetlands; E.O. 11988 Floodplain Management; E.O. 12898 Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations; E.O. 11593 Protection and Enhancement of Cultural Resources; E.O. 13007 Indian Sacred Sites; E.O. 13287 Preserve America; E.O. 13175 Consultation and Coordination with Indian Tribal Governments; E.O. 11514 Protection and Enhancement of Environmental Quality; E.O. 13112 Invasive Species.

The Tier 1 EIS, ROD, and other documents in the project file are available online at: *https://azdot.gov/planning/transportation-studies/sonoran-corridor-tier-1-environmental-impact-statement.* Please contact either FHWA or ADOT at the addresses provided above if you would like further documentation.

For the Sonoran Corridor Tier 1 EIS study, FHWA served as the Lead Agency while ADOT served as the Local Sponsoring Agency. For future Sonoran Corridor activities and Tier 2 studies, ADOT has assumed FHWA's responsibility for carrying out NEPA under two separate Memorandums of Understanding (MOU) that have been executed by FHWA and ADOT: *Responsibility for Categorical Exclusions MOU* pursuant to 23 U.S.C 326 (326 MOU), and *Surface Transportation Project Delivery Program MOU* pursuant to 23 U.S.C. 327 (327 MOU). Under these assignments, ADOT is responsible for carrying out federal environmental review responsibilities and complying with all applicable federal environmental laws, regulations, Executive Orders and policies. ADOT is solely liable for environmental decisions made on projects in Arizona funded under the Federal-aid Highway Program pursuant to either the 326 MOU or the 327 MOU.

Pursuant to Title VI of the Civil Rights Act of 1964, the Americans with Disabilities Act (ADA) and other nondiscrimination laws and authorities, ADOT does not discriminate on the basis of race, color, national origin, sex, age, or disability. Persons that require a reasonable accommodation based on language or disability should contact Joanna Bradley, ADOT Community Relations Project Manager, at (520) 388–4257. Requests should be made as early as possible to ensure the State has an opportunity to address the accommodation.

De acuerdo con el Título VI de la Ley de Derechos Civiles de 1964, la Ley de Estadounidenses con Discapacidades (ADA por sus siglas en inglés) y otras normas y leyes antidiscriminatorias, el Departamento de Transporte de Arizona (ADOT) no discrimina por motivos de raza, color, origen nacional, sexo, edad o discapacidad. Las personas que requieran asistencia (dentro de lo razonable) ya sea por el idioma o discapacidad deben ponerse en contacto con Joanna Bradley, ADOT Community Relations Project Manager, (520) 388–4257. Las solicitudes deben hacerse lo más antes posible para asegurar que el Estado tenga la oportunidad de hacer los arreglos necesarios.

(Authority: 23 U.S.C. 139(*l*)(1))

Issued on: November 4, 2021.

Karla S. Petty,

Arizona Division Administrator, Phoenix, Arizona.

[FR Doc. 2021–24627 Filed 11–12–21; 8:45 am]

BILLING CODE P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Notice of Final Federal Agency Actions on the North Coast Rail Trail Project in Santa Cruz County, California

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice of limitation on claims for judicial review of actions by FHWA and other Federal agencies.

SUMMARY: This notice announces actions taken by FHWA and other Federal agencies that are final. This final agency action relates to a proposed development of 7.5-mile multi-use bicycle and pedestrian trail along the Santa Cruz County Regional Transportation Commission (RTC)-owned railroad corridor and parking lot improvements at two locations along Highway 1, in unincorporated Santa Cruz County, California. The FHWA's Finding of No Significant Impact (FONSI) provides details on the Selected Alternative for the proposed improvements.

DATES: By this notice, FHWA is advising the public of final agency actions subject to 23 U.S.C. 139(*l*)(1). A claim seeking judicial review of the Federal agency actions on the highway project will be barred unless the claim is filed on or before April 14, 2022. If the Federal law that authorizes judicial review of a claim provides a time period of less than 150 days for filing such claim, then that shorter time period still applies.

FOR FURTHER INFORMATION CONTACT: Dustin Robbins, Project Manager, Federal Highway Administration, Central Federal Lands Highway Division, 12300 W Dakota Avenue, Suite 380, Lakewood, Colorado 80228, Telephone (720) 963–3586, Email: *dustin.robbins@dot.gov.* Regular office hours are 8:00 a.m. to 5:00 p.m. (Mountain Time).

SUPPLEMENTARY INFORMATION: Notice is hereby given that FHWA has taken a final agency action by issuing FONSI for the following highway project in the State of California: North Coast Rail Trail Project in Santa Cruz County.

The project includes the development of a 7.5-mile multi-use trail proposed to extend along the coastal side of the RTC-owned railroad corridor from the Town of Davenport to Wilder Ranch State Park in Santa Cruz County. The project would include a paved path with striping and parallel unpaved path and shoulder. The Project would also include trail connections from Davenport Beach, Bonny Doon Beach, and Panther/Yellowbank Beach parking lots as well as improvements to Davenport Beach and Panther/Yelllowbank Beach parking lots along the alignment. Fencing would also be installed between the trail and agricultural fields at some locations where natural or geographic barriers do not exist to inhibit trespassing.

The FHWA's action, related actions by other Federal agencies, and the laws under which such actions were taken, are described in the Environmental Assessment (EA) approved on October 23, 2020, and the FONSI approved on October 8, 2021, and other documents in the project file. The EA and FONSI are available for review by contacting FHWA at the addresses provided above. In addition, these documents can be viewed and downloaded from the project website: *https://highways.dot.gov/federal-lands/projects/ca/monterey-bay-1.* This notice applies to all Federal agency decisions as of the issuance date of this notice and all laws under which such actions were taken, including but not limited to:

1. *General:* National Environmental Policy Act (NEPA) [42 U.S.C. 4321–4351]; Federal-Aid Highway Act [23 U.S.C. 109 and 23 U.S.C. 128].

2. *Air:* Clean Air Act [42 U.S.C. 7401–7671(q)].

3. *Land:* Section 4(f) of the Department of Transportation Act of 1966 [49 U.S.C. 303]; Landscaping and Scenic Enhancement (Wildflowers) [23 U.S.C. 319].

4. *Wildlife:* Endangered Species Act (ESA) [16 U.S.C. 1531–1544 and Section 1536], Marine Mammal Protection Act [16 U.S.C. 1361], Anadromous Fish Conservation Act [16 U.S.C. 757(a)–757(g)], Fish and Wildlife Coordination Act [16 U.S.C. 661–667(d)], Migratory Bird Treaty Act [16 U.S.C. 703–712], Magnuson-Stevenson Fishery Conservation and Management Act of 1976, as amended [16 U.S.C. 1801 *et seq.*].

5. *Historic and Cultural Resources:* Section 106 of the National Historic Preservation Act of 1966, as amended [16 U.S.C. 470(f) *et seq.*]; Archeological Resources Protection Act of 1977 [16 U.S.C. 470(aa)–470(ll)]; Archeological and Historic Preservation Act [16 U.S.C. 469–469(c)]; Native American Grave Protection and Repatriation Act (NAGPRA) [25 U.S.C. 3001–3013].

6. *Social and Economic:* Civil Rights Act of 1964 [42 U.S.C. 2000(d)–2000(d)(1)]; American Indian Religious Freedom Act [42 U.S.C. 1996]; Farmland Protection Policy Act (FPPA) [7 U.S.C. 4201–4209].

7. *Wetlands and Water Resources:* Clean Water Act (Section 404, Section 401, Section 319) [33 U.S.C. 1251–1377]; Coastal Barrier Resources Act [16 U.S.C. 3501–3510]; Coastal Zone Management Act [16 U.S.C. 1451–1465]; Land and Water Conservation Fund (LWCF) [16 U.S.C. 4601–4604]; Safe Drinking Water Act (SDWA) [42 U.S.C. 300(f)–300(j)(6)]; Rivers and Harbors Act of 1899 [33 U.S.C. 401–406]; Wild and Scenic Rivers Act [16 U.S.C. 1271–1287]; Emergency Wetlands Resources Act [16 U.S.C. 3921, 3931]; TEA–21 Wetlands Mitigation [23 U.S.C. 103(b)(6)(M, 133(b)(11)]; Flood Disaster Protection Act [42 U.S.C. 4001–4128].

8. *Hazardous Materials:* Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) [42 U.S.C. 9601–9675]; Superfund Amendments and Reauthorization Act of 1986 (SARA); Resource Conservation and Recovery Act (RCRA) [42 U.S.C. 6901–6992(k)].

9. *Executive Orders:* E.O. 11990 Protection of Wetlands; E.O. 11988 Floodplain Management; E.O. 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations; E.O. 11593 Protection and Enhancement of Cultural Resources; E.O. 13007 Indian Sacred Sites; E.O. 13287 Preserve America; E.O. 13175 Consultation and Coordination with Indian Tribal Governments; E.O. 11514 Protection and Enhancement of Environmental Quality; E.O. 13112 Invasive Species.

(Catalog of Federal Domestic Assistance Program Number 20.205, Highway Planning and Construction. The regulations implementing Executive Order 12372 regarding intergovernmental consultation on Federal programs and activities apply to this program.)

Authority: 23 U.S.C. 139(*l*)(1).

Amy Fox,

Acting Division Director, Lakewood, Colorado.

[FR Doc. 2021–24618 Filed 11–12–21; 8:45 am]

BILLING CODE 4910–RY–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Regulation Project

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Internal Revenue Service (IRS), as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on information collections, as required by the Paperwork Reduction Act of 1995. The IRS is soliciting comments concerning Election Involving the Repeal of the Bonding Requirement.

DATES: Written comments should be received on or before January 14, 2022 to be assured of consideration.

ADDRESSES: Direct all written comments to Andres Garcia, Internal Revenue Service, Room 6526, 1111 Constitution Avenue NW, Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of this revenue procedure should be directed to Martha R. Brinson, at (202) 317–5753, or at Internal Revenue Service, Room 6526, 1111 Constitution Avenue NW, Washington, DC 20224, or through the internet at *Martha.R.Brinson@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Election Involving the Repeal of the Bonding Requirement.

OMB Number: 1545–2120.

Revenue Procedure Number: 2008–60.

Abstract: This revenue procedure affects taxpayers who are maintaining a surety bond or a Treasury Direct Account (TDA) to satisfy the low-income housing tax credit recapture exception in § 42(j)(6) of the Internal Revenue Code (the Code), as in effect on or before July 30, 2008. This revenue procedure provides the procedures for taxpayers to follow when making the election under section 3004(i)(2)(B)(ii) of the Housing Assistance Tax Act of 2008 (Pub. L. 110–289) (the Act) to no longer maintain a surety bond or a TDA to avoid recapture.

Current Actions: There are no changes to the paperwork burden previously approved by OMB.

Type of Review: Extension of a currently approved collection.

Affected Public: Individuals and Households, Businesses and other-for-profit organizations.

Estimated Number of Respondents: 7,810.

Estimated Time per Respondent: 1 hour.

Estimated Total Annual Burden Hours: 7,810.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. Comments will be of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information has practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: November 9, 2021.

Martha R. Brinson,

Tax Analyst.

[FR Doc. 2021–24826 Filed 11–12–21; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Form 637

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Internal Revenue Service (IRS), as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on information collections, as required by the Paperwork Reduction Act of 1995. The IRS is soliciting comments concerning Application for Registration (For Certain Excise Tax Activities).

DATES: Written comments should be received on or before January 14, 2022 to be assured of consideration.

ADDRESSES: Direct all written comments to Andres Garcia, Internal Revenue Service, Room 6526, 1111 Constitution Avenue NW, Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to Martha R. Brinson, at (202) 317–5753, or at Internal Revenue Service, Room 6526, 1111 Constitution Avenue NW, Washington, DC 20224, or through the internet at *Martha.R.Brinson@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Application for Registration (For Certain Excise Tax Activities).

OMB Number: 1545–1835.

Form Number: 637.

Abstract: Form 637 is used to apply for excise tax registration. The registration applies to a person required to be registered under Revenue code section 4101 for purposes of the federal excise tax on taxable fuel imposed under Code sections 4041 and 4071; and to certain manufacturers or sellers and purchasers that must register under Code section 4222 to be exempt from the excise tax on taxable articles. The data is used to determine if the applicant qualifies for the exemption. Taxable fuel producers are required by Code section 4101 to register with the Service before incurring any tax liability.

Current Actions: There are no changes being made to the form at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Business or other for-profit organizations, and not-for-profit institutions, and farms.

Estimated Number of Respondents: 2,000.

Estimated Time per Respondent: 11 hrs., 19 mins.

Estimated Total Annual Burden Hours: 22,620.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. Comments will be of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information has practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: November 9, 2021.

Martha R. Brinson,

Tax Analyst.

[FR Doc. 2021–24825 Filed 11–12–21; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Form 8835

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Internal Revenue Service (IRS), as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on information collections, as required by the Paperwork Reduction Act of 1995. The IRS is soliciting comments concerning Renewable Electricity, Refined Coal, and Indian Coal Production Credit.

DATES: Written comments should be received on or before January 14, 2022 to be assured of consideration.

ADDRESSES: Direct all written comments to Andres Garcia, Internal Revenue Service, Room 6526, 1111 Constitution Avenue NW, Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to Martha R. Brinson, at (202) 317–5753, or at Internal Revenue Service, Room 6526, 1111 Constitution Avenue NW, Washington, DC 20224, or through the internet at *Martha.R.Brinson@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Renewable Electricity, Refined Coal, and Indian Coal Production Credit.

OMB Number: 1545–1362.

Form Number: 8835.

Abstract: Form 8835 is used to claim the renewable electricity production credit. The credit is allowed for the sale of electricity produced in the United States or U.S. possessions from qualified energy resources. The IRS uses the information reported on the form to ensure that the credit is correctly computed.

Current Actions: There are no changes being made to the form at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Business or other-for-profit organizations and individuals.

Estimated Number of Respondents: 477.

Estimated Time per Respondent: 18 hours, 26 minutes.

Estimated Total Annual Burden Hours: 8,720.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. Comments will be of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information has practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: November 9, 2021.

Martha R. Brinson,

Tax Analyst.

[FR Doc. 2021–24824 Filed 11–12–21; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Quarterly Publication of Individuals, Who Have Chosen To Expatriate

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice.

This notice is provided in accordance with IRC section 6039G of the Health Insurance Portability and Accountability Act (HIPPA) of 1996, as amended. This listing contains the name of each individual losing United States citizenship (within the meaning of section 877(a) or 877A) with respect to whom the Secretary received information during the quarter ending September 30, 2021. For purposes of this listing, long-term residents, as defined in section 877(e)(2), are treated as if they were citizens of the United States who lost citizenship.

Last name	First name	Middle name/initials
ABELIN	STEFAN	M
ABELIN	YVONNE	B
ABIAD–EID	CHLOE	
ABIAD–EID	KRYSTEL	
ACKERMANN	LUKAS	S
AIDRUS	TANIA	S
AKAGI	KAI	MATTHEW
ALBRECHT	DANIEL	J
ALKON–FISHER	MARGARET	R
AL–MALAZI	MAYYASA	S
ALPERSTEIN	MELISSA	E.B.
ALTHAUS	KENNETH	S
AL–UBAID	AHMAD	

Last name	First name	Middle name/initials
ALVETRO	JAMES	
ALWANI	GIRISH	
ANDERS	LAURA	
ANDERSON	CHARLENE	
ANDERSON	JANE	S
ANDERSON	MORRIS	A
ANDRADE	RACHEL	J
ANDREWS	JOAN	I
ANNABELL	TRACY	L
APPLEYARD	C MARK	K
ARLANT	ALESSANDRO	ALBERTO
ARMSTRONG	JANA	A
ARNOLD	ROBIN	E
ASHTON	LEIGH	M
ASJES	LUCAS	JAN
ATMA	DIANE	J
AUGER	ANTOINE	
AUSTIN	AMY	
AYLWARD	MICHAEL	P
BAIRD	CHARLES	L
BAKER	MARTIN	G
BAKER	SEAN	F
BANDITT	SUSAN	J
BANG	MI	RAN
BANK–DE ZEEUW	DINA	
BARATA	MELANIE	GOETTI DIAS
BARATOFF	CYRIL	
BARMAN	RODERICK	A
BARNES	CHRISTIAN	L
BARNETT	SUSAN	P
BARRETT	NICOLE	
BARTALENA	GUIDO	
BARTON	JOAN	
BASIC–BEGAGIC	EMINA	
BAUMAN	PAUL	D
BAUMANN	ERICH	S
BAUMANN STETTLER	STEFANIE	
BAUR	HANNA	C
BAUTOVICH	TANYA	M
BEATTIE	ANDREW	J
BEATTY	WILLIAM	F
BECKER	CAROLINA	F
BECKER	ELAINE	M
BECKER	HOLLY	
BECKLEY	TYLER	C
BEGERT	MERYL	H
BENITEZ	JOSE	F
BENNETT	HUDDIE	A
BENSON	ROBERT	A
BERGE	ANNETTE	C
BERGE	ANNETTE	C
BERGERS	WILHELMUS	F
BERLIN	RAGNA	
BERNAZANI	ODETTE	
BERRYHILL	ROBERTA	H
BERTOLINO	CARLY	M
BEVIS	COLLEEN	B
BIEG	MARTIN	T
BIKOV	MARIA	M
BINFET	MATTHEW	J
BINGHAM	ANGUS	G
BIRNIE	KATHRYN	A
BLACK	CELESTE	M
BLACKWELL	KRISTINA	J
BLANCHARD	PHILIPPE	ALEXANDRE
BLANCHET	MARIE–EVE	
BLOCH	ERIC	
BLOCH	MARION	B
BLONDHEIM	RACHEL	J
BLUMBERG	STEPHEN	LOUIS
BOEVE	ERIC	
BOGAN	ERICA	M
BOIVAN	INGRID	A
BOLLETER	ANDRES	S

Last name	First name	Middle name/initials
BONICATTI	PATRICIA	W
BORST	NORA	
BOWER	JOHN	W
BOWER	LESLIE	
BOWERS	RYAN	G
BOYCE	THOMAS	M
BRADBURY	ALISON	P
BRADBURY	CHRISTOPHER	J
BRANCH	BARBARA	
BRANDT	WILLEM	R
BRAUER	SUSANNE	M
BREITENMOSER	DANIEL	
BREITENMOSER	MARC	L
BRENNAN	TANIA	
BRENNINKMEYER	EDWARD	
BREVIG	KAHN	
BROADWELL	MARY	P
BROOKS	JOAN	C
BROWN	REBECCA	L
BROWN	ROBERT	A
BROWNRIGG	DANAE	C
BUCKLAND	NIGEL	C
BURGERS	HENDRIKA	J
BURGIN	KARL	E
BURKHARDT	SHANE	
BURNETT	EMILY	R
BURTON–MCCARTHY	HELEN	
BUSCH–PETERSEN	MARGRETHE	B
CABRALES	JUAN	
CACCHIONE	PATRICIA	
CANALES	JUAN	M
CAPELLI	SANDRA	
CARRAHER BLANCHE MCGUIRE	MARTINE	CAROLINE
CASEY	ASHLEY	J.
CASTRACANE	LUBA	
CATHCART	DAVID	
CHAO	FALTON	T S
CHAPMAN	JESSE	C
CHAPMAN	MICHELLE	T
CHARNLEY	ANDREW	A
CHARNLEY	CHRISTOPHER	J
CHARNLEY	MICHAEL	J
CHAUMET	LUCY	A
CHEN	JENNIFER	H
CHEN	PEILAN	
CHENG	ALVIN	K
CHIASSON	NATHALIE	A
CHIKIRA	MASAKAZU	
CHIVERS	DANA	
CHIVERS	DAVID	H
CHOW	MONICA	L
CHRISTODOULOPOLOUS	ILIAS	
CHRISTOPOULOU	DINA	
CHU	ALISON	
CHU	MEGAN	CHAW WEI
CHUANG LEE	LIH YAN	
CHURCH	NANCY	
CILLONIZ REY	ANDREA	
CLARK	ELIZABETH	
CLARK	MARGARET	
CLARK	ROBERT	
CLARK	SHANNON	A
CLARKSON	HELENE	E
CLINGMAN	DAVID	
CLOUSTON	PERRY	
COCKRELL	HARRY	A
CODEVILLA	CARLO	E
COE	CORNELIA	J
COHEN	RINA	I
COLLYER	MICHAEL	GEORGE
COLUCCIO	CECILIA	A
COLVIN	SUSAN	N
COMEAU	MELANIE	
CONRADS	HANS	G

Last name	First name	Middle name/initials
CONWAY	JOANNE	C
CONWAY	LAURA	J
COOMBS	CAROLINE	A
CORKUM	KELLY	L
CORNOFSKY	LARRY	
CORVES	CHARLOTTE	A F
COTMAN	AMANDA	S
COX	DARCY	
CREIGHTON	DAVID	
CRISTIANO	LORENZO	
CRIVELLI–AMSTUTZ	MIRIELLE	MIRA
CROCKER	PETER	J
CROSHERE	ROBERT	F
CROXFORD	ELIZABETH	J
CUDD	THOMAS	V
CUI	XIANGGEN	
CURTI	ARIANE	C
CYMLICH	INNA	
D'AILLY	BOUDEWINE	D.
DAITZ	LAURA	
DAKIN	JAMES	L
DALTON	FREDERICK	V
D'ANGELA–LALONDE	YVONNE	
DANIELI	ANNA	TERESA
DANIELI	VALENTINA	F
DANOWSKI	GUSTON	S
DARCY	FUMIKO	MITSUDA
DARLING	MADISON	
DAVISON	CHRISTOPHER	
DAWSON	CELIA	P
DE CARVALHO	ERIK	
DE LU	KATIA	G
DE MENEGHI	VICKI	L
DE MESTRAL	SOPHIE	A
DE POULPIQUET DU HALGOUET	TANGUY	
DEACON	STEPHEN	R
DEDOMING	EVA	N
DELAHAIJ	ERIC	J
DELONNOY–JUSTICE	VICKI	M
DEN DAAS	CHRISTIAN	D
DEN DAAS	JAN–WILLEM	T
DENNING	PIERS	W
DENNIS	NEIL	0
DESBIENS	NATHALIE	
DETWILLER	DENNIS	
DETWILLER	HILARY	
DEVLIN	ALAN	J
DEWITTE	NATHALIE	K
DEXTER	DAVID	K
DICKINSON	SHELLEY	L
DICKMAN	JEROME	E
DICKMAN	SHARRON	
DIJK	HENDRIK	J
DIKKERS	DERRICK	
DING	CHUN	R.
DIPIETRO	PETER	
DOOLHOF	MANOUK	N
DOUCETTE	DESIRE	J
DRIVER	KELLY	
DROUIN	JOCELYNE	
DRUMMOND	MARY ANNE	
DUARTE	ROBERTO	D
DUNN	PATRICIA	A
DUNNE	MARCELA	O
EASDALE	REBECCA	L G
EAST	ROSEMARY	E
EDDINGTON	SCOTT	D
EDGERTON	SYLVIA	L
EDWARD	MIKUCKI	J
EDYE	ISABELLE	
EDYE	MICHAEL	
EGAN	TIFFANY	I
EGERER	CHRISIAN	P
EIDEL	OLIVER	

Last name	First name	Middle name/initials
ELDRIDGE	SHEILA	
ELY	BRODERICK	P
EMSERMANN	ISABEL	
ENGLER	COLIN	D
EPLATTENIER	NATHALIE	L
EPSTEIN	JOHANN	G
ESLAVA	PEDRO	J
EVAMY	ANDREW	D.
EVANS	MEGAN	
EWING	MEGAN	
FANG	PAMELA	J
FARMANFARMAIAN	CHARMINE	
FAST	LORETTA	J
FAUCETT	EBONY	
FAWCUS	DEBERA	A
FAY	LEE	
FELDMAN	SAMUEL	
FELDMAYER	MATTHIAS	
FENCHEL	SULYA	
FENNEFORE	MARIE	K
FERCHER	KURT	C
FERNANDEZ TORRES	ELIA	
FERRAGAMO	VITTORIA	
FERRO	ROBERTO	G
FIBIGER	HANS	C
FISCHER	HERBERT	
FISCHER	JOHANNES	M
FISCHER	SHIRLEY	S
FISCUS	JAMES	D
FISCUS	TROY	D
FITZPATRICK	ELEANOR	
FITZPATRICK	MARK	
FIVAZ	JULIETTE	
FLEHR	JUDITH	
FLIKKEMA	HARRY	JACK
FOKKEMA	MARGARET	J
FOLLOWS	JOSEPH	F
FOLOT	FRANCOIS	
FORNER	MALIA	C
FORWOOD	SAMANTHA	
FOWLER	MICHAEL	C
FOX	FREDERIC	
FRASA–ODOK	SELMA	
FREEDMAN	AYRIE	L
FREEDMAN	LEXIE	A
FREY	NICOLE	CECILIA
FREY	PERRY	
FRICKER	JOSEPH	A
FRIESEN	DONALD	K
FULLER	MIMI	G
FUNG	WING	SEE
FURTH	DIANA	A
FUTAMI	AKIKO	
GAA	JAMES	C
GAA	MARILYN	A
GALLOWAY	DIANE	
GALZA	LOIS	C
GAMBLE	JACQUELYN	D
GAMSGAARD	JANE	E
GANS	MICHAEL	J
GARCIA–BARRERO	GUILIERMO	A
GARDNER	KENNETH	R
GARRAND	LISA	A
GAUTHIER	MARION	P
GAUTHIER	THOMAS	P
GERARD	GERARD	M
GERATH	GUY	W
GERATH	THERESA	
GERRITY	SCOTT	
GIBBONS	JOHN	CALEB
GIBSON	ANNIKA	
GIBSON	YLVA	M
GIGUERE	LOUISE	
GILGEN	THOMAS	M

Last name	First name	Middle name/initials
GILLIAN	KATHERINE	M
GOEDEL	CLAUDINE	S
GOERGEN	STACY	K
GOETTSCH	STEFAN	
GOLDBLATT	DEBRA	
GOLDEN	BRIAN	R
GOLDMAN	MA'AYAN	
GOLDSTEIN	DANIEL	
GOLDSTEIN	JUDY	
GOLDSTEIN	RONALD	
GONZALES	GEORGE	C
GOOD	BRYAN	D
GOODE	EDWARD	R
GOOSSEN	PAMELA	
GORIS	ILSE	
GOTTLIEB	ZACHARY	
GOTTSCHALK	BRIAN GOTTSCHALK	
GOUDGE	CARLA	C
GOULD	PHILIP	H
GRAHAME	JUDITH	J
GRANHEIM	SARA	M
GRANT	MARY	
GREAVES	MATTHEW	A
GREEN	MICHAEL	C
GREENBERG	PAUL	
GREENE	MARGARETHE	L
GROSLAND	ROBERTA	JAYNE
GROSS	ALEXANDRA	
GRUZMAN	GEORGIANA	
GUINARD	CLAUDIA	IRENE ELFRIEDE
HAAC	VICTORIA	S
HACKER	JOSEPH	S
HAGEN	JAMES	W
HAKIM	RICHARD	
HALIPERIN	VEIT	N
HALL	EDWARD	R
HALL	JAMES	P
HAMAKAWA	KEIKO	
HAMMER	RICHARD	E
HAMMONS	SUSAN	E
HANSEN	DOAN	N
HANSEN	STEN	M
HARD	RONALD	THOMAS
HARMON	COLE	MICHAEL
HARRELL–BOND	DAVID	
HARRELSON	ERLENE	
HART	SARAH	L
HART NIBBRIG	MARIA	P
HARTNAGEL	TIMOTHY	
HARTSHORN	JUDITH	E
HASHIMOTO	RIKIYA	
HASSELGRAVE	AMY	
HAYMET	ANTHONY	D
HEDIGER	MARTIN	A
HEESE	MARLON	F
HEINE	OLIVIA	K
HEITMAN	MARTHA	
HELLIWELL	BENJAMIN	A
HENDERSON	KAREN	M
HENDERSON (ZELLER)	LINDA	
HERMAN	SARAH	L
HETHERINGTON	JOYCE	A
HEWSON	NATHANIAL	
HICKLI	ALISON	H
HILL	ROBERT	J
HILTI	NORMAN	A
HIPPS	RYAN	CHRISTOPHER
HOCHSTEINER	ANNETTE	B
HOERMANN	DANEILA	
HOFSTAETTER	THOMAS	
HOFSTEDE VOS	WALTER	WILLIAM ANDREW THEODORE
HOGAN	BARBARA	
HOLDEN	PERI	A
Holt	Karen	Lee

Last name	First name	Middle name/initials
HOOKER	LISA	D
HORSTER	SOPHIA	
HOSANG	ALAIN	F
HUGHES	EMILY	G
HUGHES	MITCHELL	
HUMPHREYS	REBECCA	
HUTTON	JOANNE	
HYNDMAN	MARC	G
ILIFF	JOHN	C
ILLI	JEAN–JACQUES	
ILYN	DAVID	A
IMBACH	FRANCESCA	N
INTRATOR	ELIZABETH	R
IP	FANNY	
J	REDRO	G
JACKSON	ANNA–MARIA	M
JACQUEMIN	ALIX	
JACQUEMIN	HUQUES	
JAGER	JUDITH	
JANSE	BERNARDUS	W
JANSSON	LEIF	G
JANZEN	MICHAEL	K
JARMAN	HEATHER	N
JASPER	DALLAS	M
JASPER	LOUISE	D
JEFFS	LYNN	M
JENSEN	JOHN	T
JENSEN	MARGARET	S
JOHNSON	JAMES	A
JOHNSON	KODY	
JOHNSON	TIMOTHY	
JOHNSTON	SUSAN	L
JOLIVET	CLAIRE	A.
JOLLY	AARON	F
JONES	JENNY	V
JONES	JONATHAN	CHARLES K
JONES	MAURICE	A
KADATZ	STEVEN	
KAEGI	MANUEL	
KAEGI	RAPHAEL	
KAI	YUTA	
KAMENETZKY	DAVID	A
KAMLANG–EK	PHRA	PRAPUTT
KAMMERZELL	SUSAN	E
KANDE	BETTINA	M
KANOFF	REBECCA	
KAUENHOFEN	AYLMER	
KAZUNARI	TOKURA	
KEAST	MELANIE	M
KEAST	MIRANDA	E
KEHOE	JOHN	
KEIJER	NINA	MARCHIEN
KEIJER	THOMAS	
KELLEY	KEVIN	L
KELT	MURDO	J
KEMP–LETTKAMP	HANS	CHRISTIAN
KENNY	DEIRDRE	M
KERR	BARBARA	
KILBANE	CAROLINE	
KILBANE	MICHAEL	G
KILLEN	CATHERINE	
KILPATRICK	SONYA	F
KIM	JENNIFER	Y
KIM	SUNG UP	
KIMEL	JOSEF	GAL
KING	MICHAEL	
KISH	BRIANA	
KLEIN	KULANADDA	H
KLINE	SALLI	J
KLINEFELTER	VICTOR	A
KNUDSEN	ELLINA	MONET
KOCHENDOERFER	ANDREA	S
KOEHL	STEFAN	L
KOENIG	IRENE	URSULA

Last name	First name	Middle name/initials
KOHNSTAMM	JUSTIN	M
KOLENDA	SARA	
KOMOROWSKI	ROMAN	J
KONST	CLARE	N
KORN–NESPOR	ANNE	R
KRAEGEL	JEFFREY	JOHN
KRAIZBERG	ORNA	
KRAPIVIN	YURY	
KRAPIVINA	VICTORIA	
KREMER	HERMAN	A
KRENGEL	SVEN	
KRONENBERG	DOMINIQUE	D.
KRONENTHAL	MELISSA	
KULKARNI	SHRUTI	N
KURKCUYAN	PETER	B
LACKNER	ANDREAS	
LADEBAT	LIONEL	J
LAEDERICH	LIOUBA	
LAEMMLI	CAROLINE	MAYA
LAKIN	ERIC	DANIEL
LAM	RICKY	KA–CHI
LAMBETH	DEAN	A
LAMONT	LINDA	
LAMOTHE	JONATHAN	
LANDON	LEAH	J
LANG	DAVID	JOHN
LANG	KEVIN	RICHARD
LANNOY	GUY	G
LAPIDUS	DIANE	C
LARSEN	TRINA	M
LASNET	CECILY	
LATRY	JEAN	P
LAUER	SONJA	
LAURIE	AVRUM	
LAVER	BRID	
LAVER	MICHAEL	
LAWSON	KATHERINE	
LAWTON	RON	D
LE GRAND DES CLOIZEAUX	FRANCOIS	MARIE
LE ROUX	SOPHIE	I
LEA	RYAN	
LEE	DAVID 2019	
LEE	RICHARD	M
LEE	SEAN	
LEE	TIMOTHY	A
LEE	YATING	
LEFEBVRE	ALEXANDRE	F
LEGER	MELANIE	J
LELKE	BIANCA	
LENG	MARIA	C
LEPLEY–GABRIEL	KRISTINA	
LEPRIEUR	NANCY	H
LESLIE	HUGH	S.
LETTS	CAREY	E
LEUNG	REBECCA	
LEVITT	IAN	M
LEVITT	JOSEPH	F
LEWIS	JEREMY	B
LEWIS	MARY JANE	J
LIANG	YVONNE	Q
LIBFELD	RACHEL	
LIBFELD	STEVEN	
LIGHTBURN	PATRICIA	
LIGTHART	INGRID	G
LIN	JERRY	
LIN	TA–CHUN	
LINK	KARL	R
LOCKHART	MARC	
LOO	JON	P
LOVETT	SHARON	
LOWRY	CHRISTINA	D
lu	angel	
LUBBOCK	JULIUS	A
LUDER	PANSCAL	MATTHIAS

Last name	First name	Middle name/initials
LUDER	PHILLIPP	R
LUX	ANDREW	C
LVOVSKY	ALEXANDER	I
LYALL	ANTHONY	
LYONS	HELEN	
MACAULAY	FANE	E
MACCARTHAIGH	HELENA	A
MACDERMOTT	KAREN	L
MACDONALD	COLIN	
MACDONALD	PATRICIA	LUCILE
MACDONALD	TODD	
MACEDO	GABRIELA	ALVES
MACFARLAND	HAROLD	C
MACGREGOR	KATHERINE	
MACISAAC	ANTHONY	MARSHALL
MACKAY–SMITH	ALEXANDER	
MAGGISANO	MELINDA	
MAGLIANA	INGEBORG	
MAGNAN	ANTOINE	
MAHAN	MARILYN	
MAHAN	THOMAS	F
MAKIN	CAMERON	
MANDELSON	SARAH	
MANKTELOW	LUCY	E
MARCEAU	JONI	
MARGARIA	ROBERTO	A
MARIAN	MICHAEL	W
MARINELLO	GIUSEPPINA	
MARKS DE CHABRIS	LIONEL	
MAROLF	CHRIS	
MARSICO	JOSEPH	F
MARTEL	PAOLO	ROBERTO M
MARTIN	KARIN	
MARTIN	MARIE–JOSEE	
MATTHEW	NICK	
MATTHEWS	ROBERT	B
MATTIE	JOHANNE	
MATTSON	DAVID	L
MATTSON	VIRGINIA	C
MAXRATH	LARS	
MCCARTHY	SIMONE	C
MCCARTHY	SIMONE	C
MCCARTHY	STEPHEN	E
MCDONALD	WENDY	C
MCEVILLY	SEAN	
MCKENNA	JOSEPH	T
MCKOY	MADISON	J
MCLAREN	WHITNEY	H
MEIER	NATHANAEL	E
MELLER	EMILY	
MELO	RAFAEL	
MELVIN	REINE	MARIE
MERCER	MARC	ARTHUR
MERCHEL	EWA	A
MERCURY	NANCY	P.
MERKERT	MONA	KRISTINA
MERRY	DOUGLAS	J
METAXES	VICTORIA	E
METELIK	IRENE	A
METHERELL	DONALD	S
MEYER	FELIX	
MEYER	ILLANA	S
MEYER	SEAN	Z
MEYERSEN	ANNETTE	
MEYN	THORE	
MICHAUD	MONIQUE	M
MILLAR	CHRISTOPHER	PATRICK
MILLER	JANET	
MILNE	EDWARD	L
MILNER	DAPHNE	
MINTO	RACHAEL	M
MIRANI	RAHUL	C
MIRO	ADRIAN	
MISLIN	JONAS	R

Last name	First name	Middle name/initials
MITCHELL	LISA	
MOATE	PETER	J
MOATE	THERESA	M
MOERITZ	FREDERICK	
MOHLER	STEVEN	M
MOLLER	SHAULA	
MOLTZ	KAREN	
MONEY	JOHN	STEPHEN
MOORE	DAVID	
MOORMAN	ROBIN	T
MORAWITZ	DELEAH	
MORENCY	MARY	E
MOREY	KEVIN	C.
MORIKAWA	EIZI	
MORLEY	SIMON	A
MORRIS	JASON	T
MORRISON	KATHRYN	C
MORSE	BRADFORD	W
MOSELEY	ANDREW	
MOSELEY	CHERYL	J
MOSHER	PAULINE	B
MOSKO	CHEYENNE	S
MOSS	MIRIAM	
MULVENNA	CHARLES	
MUNCH–HANSEN	KATRINE	
MUNN	FRANCES	
MUNRO	JAMES	L
NAKAYAMA	KAZUNORI	
NALLAMILLI	PPASANTI	
NANDIGAM	RAMAKRISHNA	M
NASH	JUSTIN	J
NASH	MARY	T
NASH	JANINE	DEPPER
NASSOS	ANNELISE	K
NEAVE	EDWIN	H.
NEDROW CARPENTER	MARCY	A
NEIDERBERGER	ANDREAS	P
NEIDHART	LUKAS	E
NEJATIAN	KASRA	
NEUBRAND	SALLIE	R
NEUMANN–SEILER	HERTA	MARIA
NEUMAYR	EMILY	J
NEWBATT	FRANCIS	P
NEWHOUSE	NANCY	
NGUYEN	TAN	N
NGUYEN–PHUONG	DIEU–ANH	
NGUYEN–PHUONG	LAM	
NICHOLAICHUK	IRIS	
NIEDERBURGER	MOLLY	A. ALLEN-
NIEDERMEYER	SUSANNE MARIA	FICKL
NIELSON	DAVID	J
NIEUWKERK	JAN	A.
NOCHIMSON	ROBERT	M
NOLAN	JESSICA	A. C.
NOMURA	YASUYO	
NORRIS	GRAHAM	C
OBERG	JEFFREY	E
OBYRNE	SHARON	
ODENTHAL	KARIN	
O'DONNELL	JACQUELINE	
OH	LYNETTE	
OJEISEKHOBA	MOSES	I
OLANDER	SUSANNE	
ONG	FREDERICK	E
ONO WIER	KATSUYO	
ORR	SIMON	KUEN FUNG
OSKARSDOTTIR	GUDRUN	
OTSUKA	SHINICHI	
Otten	Roderik	Paul
OYAMA	TOSHIHISA	
palazzo	albert	p
PALMER	JAMES	H
PARE	PATRICE	
PARRY	BRADLEY	K

Last name	First name	Middle name/initials
PARSA	FARIDEH	
PARVATHAM	VIJAYASAI	
PASCALE	FRANCIS	M
PASSINGHAM	JOHN	G.R.
PATEL	AKASH	M
PATEL	PRAVINBHAI	
PATTERSON	NIGEL	S
PAUL	JOSEPH	A
PEACE	BIANCA	JADE
PEACOCKE	CHRISTOPHER	JON
PENFORD	LYNNE	E
PEREZ–ROJAS	NATHALIA	
PERL	MICHEL	R
PETCH	CHRISTOPHER	J
PETCH	WILLIAM	M
PETER	DEANNE	RUTH
PETITCLERC	JOSEE	
PETITCLERC	NANCY	
PFEIFER	ISRAEL	
PHILLIPS	MARCIA	B
PIASECKI	WOJCIECH	
PICARD	LAUREEN	
PIECZONKA	ROSALIND	
PIERA	LEWIS	B
PIERRE	BORIS	J
PIMBLOTT	KERRY	L
PIROTTA	DANIE	
PITTS	MARY	LOUISA
PLANT	JANET	L
PLANTINGA	MARGARET	
POLLACK	SHOSHANA	
POLLEMAN	SARAH	E
POPESCU	DIANA	MIHAELA
POPOVIC	MATEJA	
PORTER	LISA	Y
POULSEN–JUDGE	CONILYN	
POWELL	LILLY	
PRITCHARD	CATHERINE	
PRZEDBORSKI	SERGE	
PU	JIMMY	
PURCELL	MYRLIA	NORA
RADEMACHER	DANIELA	SUZANNE
RAE	ANDREW	
RAFFEL	IAN	
RAINER	RICHARD	
RAO	SANJAY	C
RAPP	DONNA	E
RATHBONE	ERIN	NICOLE
REGAN	THOMAS	D
REGUEIRO	ALEXANDER	
REITZNER	SIBYLLA	G
RENZI	RENALDO	CIRO
RENZI	ROBERTO	SERAFINO
REUTHER	ANDREAS	FLORIAN
REYES	DANIELE	ROBERT
RIBBING	KRISTINA	I
RICHENS	SIMON	P
RICKER	JOHN	M
RINGWALD	BIANCA	
RITONJA	LURA	M
RIVIERE–BARBIER	ANAELLE	APRIL
ROBINSON	ALIDA	
ROBINSON	SIMONE	
ROBINSON	JANE	HIPPISLEY
ROBLES	IVAN	R
ROBLES	MICHELLE	A
ROEDER	SVEN	HANS
ROLLER	KRISTA	D
ROMASCHIN	VERONICA	
ROSE	WILLIAM	D
ROSENBERG	HEIDI	
Rosenberg	Michael	Geoffrey
ROSS	LOUIS	A
ROUX	JEAN–DENIS	

Last name	First name	Middle name/initials
ROWLAND	URSULA	
ROWLANDS	AARON	J
ROWLANDS	AARON	J
ROY	ANNE	M
ROY	JEREMY	
ROY	ROBERT	G
RUSSELL	TANIA	R
RUTGERS	AMANDA	
RUTGERS	TANNER	
RUTLAND	GRACE	CHARLOTTE
RYAN	PHOEBE	H
SAADIEH	OSKAR	WALID
SAADIEH	VIKTOR	WALID
SABEAN	SHELLY	R
SADEGHI	HASSAN	R
SADEGHI	CHRISTINE	DIANE LEA
SAKAKIBARA	MASARU	
SAKAKIBARA	SACHIKO	
SALETU	ALEXANDER	B
SALETU	MICHAEL	T
SALL	CONNIE	
SAMPAIO	JULIANA	SECCHIM
SANG	ROSE	H. FREY
SASAKI	YUJI	
SASANUMA	TOICHI	
SASSE	ROLF	P
SASSOON	VICTOR	
SBROCCHI	STEPHANIE	
SCHAERER	ALAN	C
SCHENCK	LINDA	E
SCHENCK	ROBERT	G
SCHILLEREFF	H	SCOTT
SCHLOSSER	CHRISTOPHER	R
SCHMELING	MIRIAM	
SCHMID	EDITH	M
SCHMIDT	ANNETTE	
SCHMIDT	COLIN	
SCHNAPPER	NOACH	L
SCHNEIBDER	TIM	C
SCHNEIDER	MADELEINE	
SCHNEIDER	MAXIMILIAN	K
SCHULTZ	VICTORIA	T
SCHWALBACH	SABASTIAN	
SCOTT	KIMBERLY	A
SEGGERMAN	NATALIA	CARRIE ATHA
SETTLES	MARCUS	R
SEVENSTER	MERLIJN	
SHAFFER	MILO	S
SHALAM	EMANUEL	B
SHARPE	WILLIAM	
SHAW	DAVID	
SHELLITO	MICHAEL	J
SIEGELE	JESSICA	M
SILBERMAN	MICHAEL	BOLEK
SIMAN–TOV	EITAN	
SIMONNARD	ALEXIA	
SINCLAIR–LAPPI	KRISTA	STEPHANIE
SING MING	HUTT	
SIROTNIK	GARETH	S
SITTIG	DALE	
SMITH	CHRISTOPHER	
SMITH	JENNIFER	M
SMITH	JULIA	YVONNE ANGELA CAMPBELL
SMITH	LEON	T
SMITH	LISA	M
SMITH	STEFAN	A
SMITH	WILLIAM	S
SMITHERS	AMELIA	O
SOCASH	RYAN	A
SORENSEN	JOHN	A
SPARKS	DERRICK	
SPIES	ANNA	
SPINELLI	ULRICA	
SPOTORNO	ALESSANDRO	

Last name	First name	Middle name/initials
SPRAY	CHRISTOPHER	J
STANFORD	ROYDEN	J
STEELE	GREGORY	R
STEGMANN	CHRISTIAN	
STEIN	DAVID	H
STEINBACK	MICHAEL	
STEINBERG	FREDRIC	M
STEPAK	RAQUEL	
STEWART	LILIAN	T
STOTT	SARAH	
SUDMANT	SANDRA	R
SULLIVAN	JUNE	E
SUN	CHUANMING	
SUTTER	BRENT	
SWIATEK	CLAUDIA	L
SWIATEK	MICHELLE	L
SWIFT	BJORN	P
SYLVAN	LILO	D
SZABO	STEVEN	M
TAKASHIMA	HIDETOSHI	
TAKASHIMA	KAZUMI	
TANNER	BARBARA	S
TANNER	STEPHAN	C
TAUZER	SASHA	TOMCZUK
TAYLOR–HELL	CATHERINE	
TAYSI	A	Y
TEHEE	RYAN	PATRICK
TEJADA	ANALEE	
TEN–WOLDE	BEVERLY	A
TERRYN	NICHOLAS	A
TESSIER	ALEXANDRE	JOSEPH
THEALL	MARGARET	
THION	STEPHANE	F
THOMAS	ALLISON	
THOMPSON	JOHN	
THOMPSON	KATHERINE	A
THOMPSON	WILLIAM	J
THOMSON	ALLAN	
THOMSON	IAN	A.
TIMMERMANS	MARJA	C
TIMMS	RYAN	JOHN
TIN	LANCELOT	
TO	CHING	WAI
TOKURA	NAOMI	
TORRANCE	IAIN	R
TOSI	PAOLA	MARIA
TRACY JR	GALEN	L
TRAMBLE	RASHUNDA	
TRGOVAC	KATHERINE	
TRUIJENS	EELKO	
TURNER	ALICIA	
TURNER	TARA	J
UNGER	KAZUYO	
VALEZ	MICHEAL	S
VAN DEN BOS	RONALD	L
VAN DEN BRANDE	CARL	A
VAN DER HULST	TJEERD	
VAN DER LINDEN	WILLEM	J
VAN DOMSELAAR	BASTIAAN	M
VAN KEULEN	CATHARINA	C
VANDEPUTTE	MARC	C
VANTHIELEN	BARBARA	LILY
VARTIAN	MICHELE	
VENTURINI	MONICA	
VERVER	MATTHYS	LEO
VIERLING	VIRGINIA	W
VINCENT	JORDAN	B
VINCENT	MARIE–CHRISTIN	
VINSON	DONNA	
VLIEG	HEDWICH	C
VLIET	RAVARA	VAN
VON DRASEK	SARAH	
VON SCHULTHESS RECHBE	CRAIG	P
VONBARLOEWEN	DANIEL	W

Last name	First name	Middle name/initials
VOUTE	SEBASTIANN	J
WAGNER	KELLY	A
WALKER	KATHERINE	L
WALKER	VANESSA	EILEEN
WALLNER	LYDIA	
WANG	JEFFREY	
WARRIMER	INEZ	L
WASKOENIG	JANINE	
WATCHERS	EUGENIA	
WAXER	MICHELLE	
WAXER	SUSAN	
WEBB	CECIL	P
WEBER	CAROLYN	
WEBER	JASMINE	N
WEEKS	GRAHAM	N
WEIBEL	LYNN	
WELLER	SHARON	R
WELLINGS	SHAUNA	
WELLMAN	DIANE	E
WELLS	OLIVIA	V
WENTZEL	RICHARD	
WEST	RACHEL	SARA
WHEATLEY	DR LOUISE	RUSSELL
WHITEHEAD	CYNTHIA	
WHITMONT	THEODOE	P
WHITTINGTON	MEGAN	
WICHMANN	FABIENNE	C
WIENS	ORAN	
WILCOX	RICHARD	J
WILHELM	CHRISTIAN	
WILLARD	GILLIAN	
WILLCOX	EMMA	GRACE
WILLCOX	JAMES	CHRISTOPHER
WILLIAMS	BRUCE	A
WILLIAMS	GRACE	
WILLIAMS	LINNEA	MARIE
WILLIAMS	MICHAEL	
WILLIAMS	ZOE	H T.
WILMOT	E GAYLE	
WILMOTT	PATRICIA	M
WILSON	CHARLES	C
WILSON	DEBORAH	
WIMMERS	SARA	E
WINCKLER	MICHELE	
WINSTON	JERONE	A
WIRTZ	KATHRYN	
WIRZ	PATRICK	THOMAS
WITZEL	FRANK	O
WOOD	THOMAS	B
WOOD	TIM	J
WOODMAN HOOPER	MARY	S
WRIGHT	JOHN	A
WRIGHT	MARY–HELEN	
WRIGHT	SUSAN	L
WU	LIANG	
XIE	LEXING	
YAMADA	KYOKO	
YANG	MICHAEL	C
YANG	SUMIN	
YEN	MICHAEL	
YOKOMORI	MAMORU	
YOOM	ALEXANDER	
YOOM	DANIEL	
YOON	JACLYN	
YOT	PATRICK	
YOUNG	WINNIE	
YOUNGER	STUART	G
ZALAPSKI	ZEN	
ZEISE	KRISTEN	M
ZEVEN	CAROL	L
ZGUSTA	RICHARD	
ZHANG	NING	
ZHAO	HUI	
ZIENKIEWICZ	ANDREW	P

Last name	First name	Middle name/initials
ZUBER	JENNIFER	A
ZUCK	AUDREY	A

Dated: November 8, 2021.

Alicia Lambreton Calhoun,

Acting Manager Team 1940, CSDC—Compliance Support, Development & Communications, LB&I:WEIIC:IIC:T4.

[FR Doc. 2021–24726 Filed 11–12–21; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–0764]

Agency Information Collection Activity Under OMB Review: Survey of Healthcare Experiences of Patients (SHEP)—Dental Care Patient Satisfaction Survey

AGENCY: Veterans Health Administration, Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) of 1995, this notice announces that the Veterans Health Administration, Department of Veterans Affairs, will submit the collection of information abstracted below to the Office of Management and Budget (OMB) for review and comment. The PRA submission describes the nature of the information collection and its expected cost and burden and it includes the actual data collection instrument.

DATES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function. Refer to ''OMB Control No. 2900–0764.''

FOR FURTHER INFORMATION CONTACT: Maribel Aponte, Office of Enterprise and Integration, Data Governance Analytics (008), 1717 H Street NW, Washington, DC 20006, (202) 266–4688 or email *maribel.aponte@va.gov.* Please refer to ''OMB Control No. 2900–0764'' in any correspondence.

SUPPLEMENTARY INFORMATION:

Authority: 44 U.S.C. 3501–3521.

Title: Survey of Healthcare Experiences of Patients (SHEP)—Dental Care Patient Satisfaction Survey, VA Form 10–10070.

OMB Control Number: 2900–0764.

Type of Review: Reinstatement of a previously approved collection.

Abstract: The mission of the Veterans Health Administration (VHA) is to provide high quality medical and dental care to eligible veterans. Executive Order 12862, dated September 11, 1993, calls for the establishment and implementation of customer service standards, and for agencies to ''survey customers to determine the kind and quality of services they want and their level of satisfaction with current services.''

The overall purpose of the Dental Care Patient Satisfaction Survey is to systematically obtain information from patients, which can be used to identify problems or complaints that need attention and to improve the quality of dental health care services. Information obtained from this dental survey will be made readily available to VA Central Office (VACO), Veterans Integrated Service Network (VISN), VHA field staff, and stakeholders as part of the Network Performance Report and via the VA Intranet. This data will be used to demonstrate that VA is providing timely, high quality health care services to patients.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The **Federal Register** Notice with a 60-day comment period soliciting comments on this collection of information was published at 86 FR 169 on September 3, 2021, pages 49599 and 49600.

Affected Public: Individuals or Households.

Estimated Annual Burden: 12,600 hours.

Estimated Average Burden per Respondent: 15 minutes.

Frequency of Response: Once annually.

Estimated Number of Respondents: 50,400.

By direction of the Secretary.

Maribel Aponte,

VA PRA Clearance Officer, Office of Enterprise and Integration, Data Governance Analytics, Department of Veterans Affairs.

[FR Doc. 2021–24865 Filed 11–12–21; 8:45 am]

BILLING CODE 8320–01–P

DEPARTMENT OF VETERANS AFFAIRS

Announcement for Public Meeting Regarding Health Care Access Standards for Veteran Community Care Program

AGENCY: Department of Veterans Affairs.

ACTION: Announcement of public meeting.

SUMMARY: The Department of Veterans Affairs (VA) is holding a public meeting to seek information from pertinent entities to inform VA's review of access standards for furnishing hospital care, medical services, and extended care services to covered veterans for purposes of the Veterans Community Care Program. Specifically, VA requests information, including but not limited to the following: Information regarding health plans on the use of access standards for the design of health plan provider networks; referrals from network providers to out-of-network providers; the appeals process for exemptions from benefit limits to out-of-network providers; and the measurement of performance against Federal or state regulatory standards. Further, VA is requesting input on veterans' experience with the access standards established in 2019.

DATES: VA will hold the public meeting virtually on December 1, 2021. The meeting will start at 8:30 a.m. Eastern Time (ET) and conclude at or before 4:30 p.m. ET.

ADDRESSES: The meeting will be held virtually and recorded on the Adobe Connect platform. Attendance will be limited to 750 individuals. Advanced registration for a maximum capacity of 30 individuals and groups who wish to offer oral comments, testimonies, and/or technical remarks is required (see registration instructions below). For listening purposes only (lines will be muted), the meeting will be available and can be accessed at the following web link: *https://vacctraining.adobeconnect.com/public-meeting-for-va-health-care-access-standards/.*

VA also published a request for information (RFI) regarding health care access standards on November 4, 2021. Per the RFI, please submit all written comments no later than December 6, 2021. Written comments may be submitted through *http://www.regulations.gov.* Comments should

indicate that they are submitted in response to ''Notice of Request for Information Regarding Health Care Access Standards.'' During the comment period, comments may be viewed online through the Federal Docket Management System at *www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Natalie Frey, Management Analyst, Office of the Assistant Under Secretary for Health for Community Care, Veterans Health Administration, Department of Veterans Affairs, 810 Vermont Avenue NW, Washington, DC 20420; telephone: 720–429–9171 (this is not a toll-free number).

SUPPLEMENTARY INFORMATION: The John S. McCain III, Daniel K. Akaka, and Samuel R. Johnson VA Maintaining Internal Systems and Strengthening Integrated Outside Networks Act of 2018 (MISSION Act), Public Law 115–182, (the VA MISSION Act) added section 1703B to title 38, United States Code (U.S.C.), which required VA to establish access standards for furnishing hospital care, medical services, or extended care services to covered veterans under the Veterans Community Care Program. VA established these access standards through rulemaking on June 6, 2019, at 38 CFR 17.4040. Section 1703B(c) specifically requires VA to consult with all pertinent Federal, private sector, and other nongovernmental entities in establishing access standards. Section 1703B(e) requires VA, not later than 3 years after the date on which VA establishes access standards, and not less frequently than once every 3 years thereafter, to conduct a review of the established access standards and submit to the appropriate committees of Congress a report on the findings and any modification to the access standards. In reviewing these access standards, VA is choosing to consult with pertinent Federal, private sector, and non-governmental entities. This public meeting serves as one of the means for VA to consult with these entities. As noted above, VA has published an RFI in the **Federal Register** to provide these entities another opportunity to provide additional information. This RFI can be found at *www.regulations.gov* under the title ''Notice of Request for Information Regarding Health Care Access Standards.'' VA will use the statements and testimonials presented at the public meeting to help review the access standards established in June 2019. VA will then submit a report, in June 2022, as required by section 1703B(e)(2).

Registration: Overall attendance in this meeting is limited to 750 individuals and overall capacity for those providing oral comments, testimonies, and/or technical remarks will be limited to 30 individuals. Individuals wanting to offer oral comments, testimonies, and/or technical remarks must request registration by emailing Natalie Frey at *Natalie.Frey@va.gov* by November 22, 2021. A message confirming that the request has been received will be sent within 2 business days, and individuals will be notified via email by November 26, 2021, confirming their registration and attendance. VA has the right to refuse registration for providing oral comments, testimonies, and/or technical remarks once the maximum capacity of 30 individuals has been reached.

Individual Registration: VA encourages individual registrations for those not affiliated with or representing a group, association, or organization.

Group Registration: Identification of the name of the group, association, or organization should be indicated in your registration request. Due to the meeting's maximum capacity for those providing oral comments, testimonies, and/or technical remarks at 30 individuals, VA may limit the number of registrants from a single group to two individuals representing the same group to allow receipt of comments, testimonies, and/or technical remarks from a broader, more diverse group of stakeholders. Efforts will be made to accommodate all registrants who wish to attend. However, VA will give priority to pertinent Federal, private sector, and non-governmental entities who request registration before November 22, 2021, 4:00 p.m. ET. Please provide the names of people your organization would like to attend, and VA will accommodate as capacity allows; organizations should list names in the order of importance of their attendance to ensure that VA allows admission for the preferred representatives. The length of time allotted for attendees to provide oral comments, testimonies, and/or technical remarks during the meeting may be subject to the number of attendees and to ensure ample time is allotted to those registered attendees. There will be no opportunity for audio-visual presentations during the meeting. Written comments will be accepted by those registered (see above instructions for submitting written comments).

Audio (for listening purposes only): Attending the live audio of the meeting is limited to the first 750 participants on a first-come, first-served basis. Advance registration is not required. Audio attendees will not be allowed to offer oral comments, testimonies, and/or technical remarks, as the audio line will be muted. Written comments will be accepted from those participating via audio (see above instructions for submitting written comments). Please note this meeting will be recorded.

Note: VA will conduct the public meeting informally, and technical rules of evidence will not apply. VA will arrange for written minutes of the meeting to be posted in the docket of the RFI. Should it be necessary to cancel the meeting due to an emergency, VA will take available measures to notify registered participants.

Agenda

08:30–12:00 Morning Public Meeting Session
12:00–13:00 Lunch Break
13:00–16:30 Afternoon Public Meeting Session
16:30 Adjourn

Public Meeting Topics

VA requests information that will assist in reviewing the access standards as required by section 1703B. This includes information regarding access standards, including but not limited to the following: Information with regard to health plans on the use of access standards for the design of health plan provider networks; referrals from network providers to out-of-network providers; the appeals process for exemptions from benefit limits to out-of-network providers; and the measurement of performance against Federal or state regulatory standards. Regarding health systems, VA requests information from the public including, but not limited to the following: The existence of standards for appointment wait times; the use of travel distance for establishing service areas; the development or use of guidelines to refer patients to out-of-system providers; the utilization of virtual health services; and the measurement of performance against Federal or state regulatory standards. VA's specific requests for information are as follows:

1. Do health plans use internal access standards for the design of provider networks and the application of in-network/out-of-network benefits that are more stringent than regulatory standards (*e.g.,* time or distance of travel, appointment wait times, provider/member ratios)? If so, what are these internal standards? Has the Coronavirus Disease 2019 (COVID–19) pandemic affected established access standards? How does the health plan measure performance against regulatory and internal access standards? How does the health plan respond to findings when access standards are not being met? Are current regulatory access standards cost

effective while maintaining quality standards? Do health plans have a process to handle routine requests from members or to refer providers for exemptions to benefit limits when members seek out of network care or a lower tier provider?

2. Do health plans allow for appeals by providers or members to request exemptions from benefit limits related to out of network care or care by a lower tier provider? Is external review allowed for such appeals?

3. What are health plan practices regarding internal, regulatory, and/or accreditation standards for appointment wait times, including variance by specialty or type of service? How does the health plan use travel distance or time and/or provider-to-population ratios in deciding which geographic areas to consider as primary or secondary service areas? How do health plans use financial modeling/impact to inform established access standards?

4. What virtual health services (*e.g.,* telehealth and telephonic) do health systems provide? Are virtual health services used to ensure compliance with established access standards?

5. Are clinicians within the health system given guidelines or rules on when to refer patients to out-of-system providers? For example, are clinicians encouraged to refer out of system if in-system wait times are longer than standard, travel time or distance to an in-system provider is too long, the patient's ability to travel is compromised, or the frequency of treatment makes travel to an in-network provider difficult?

6. What are veterans' experiences with and feedback on the VA access standards established in 2019?

Signing Authority

Denis McDonough, Secretary of Veterans Affairs, approved this document on October 29, 2021, and authorized the undersigned to sign and submit the document to the Office of the Federal Register for publication electronically as an official document of the Department of Veterans Affairs.

Consuela Benjamin,

Regulations Development Coordinator, Office of Regulation Policy & Management, Office of General Counsel, Department of Veterans Affairs.

[FR Doc. 2021–24571 Filed 11–12–21; 8:45 am]

BILLING CODE 8320–01–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–0674]

Agency Information Collection Activity: Notice of Disagreement: Appeal to the Board of Veterans' Appeals

AGENCY: Board of Veterans' Appeals, Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: The Board of Veterans' Appeals (BVA), Department of Veterans Affairs (VA), is announcing an opportunity for public comment on the proposed collection of certain information by the agency. Under the Paperwork Reduction Act (PRA) of 1995, Federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension of a currently approved collection, and allow 60 days for public comment in response to the notice. Written comments and recommendations on the proposed collection of information should be received on or before January 14, 2022.

ADDRESSES: Submit written comments on the collection of information through Federal Docket Management System (FDMS) at *www.Regulations.gov* or to *Sue Hamlin,* BVA (01C2), Department of Veterans Affairs, 810 Vermont Avenue NW, Washington, DC 20420 or email to *Sue.Hamlin@va.gov.* Please refer to ''OMB Control No. 2900–0674'' in any correspondence. During the comment period, comments may be viewed online through FDMS.

FOR FURTHER INFORMATION CONTACT: Maribel Aponte, Office of Enterprise and Integration, Data Governance Analytics (008), 1717 H Street NW, Washington, DC 20006, (202) 266–4688 or email *maribel.aponte@va.gov.* Please refer to ''OMB Control No. 2900–0674'' in any correspondence.

SUPPLEMENTARY INFORMATION: Under the PRA of 1995, Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. This request for comment is being made pursuant to Section 3506(c)(2)(A) of the PRA.

With respect to the following collection of information, BVA invites comments on: (1) Whether the proposed collection of information is necessary for the proper performance of BVA's functions, including whether the information will have practical utility; (2) the accuracy of BVA's estimate of the burden of the proposed collection of information; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or the use of other forms of information technology.

Authority: Public Law 115–55; 38 U.S.C. 5104B, 5108, 5701, 5901, 7103, 7104, 7105, 7107.

Title: Notice of Disagreement (NOD)/ Appeal to the Board of Veterans' Appeals, VA Form 10182 and VA Form 9.

OMB Control Number: 2900–0674.

Type of Review: Revision of a currently approved collection.

Abstract: Appellate review of the denial of VA benefits may only be initiated by the filing of a Notice of Disagreement with the Board. 38 U.S.C. 7105(a). *VA Form 10182 Decision Review Request: Board Appeal (Notice of Disagreement)* is required to initiate Board review of an appeal in the modernized review system as implemented by the Veterans Appeals Improvement and Modernization Act of 2017 (AMA). The *VA Form 9 Appeal to Board of Veterans' Appeals* may be used to complete a legacy appeal to the Board. The completed form becomes the ''substantive appeal'' (or ''formal appeal''), which is required by the pre-AMA version of 38 U.S.C. 7105(a) and (d)(3) to complete an appeal to the Board. Additionally, the proposed information collections allow for withdrawal of services by a representative, requests for changes in hearing dates and methods under 38 U.S.C. 7107, and motions for reconsideration pursuant to 38 U.S.C. 7103(a).

The Board is requesting to revise the currently approved OMB Control No. 2900–0674 to include an updated VA Form 10182 Notice of Disagreement. Proposed revisions to the VA Form 10182 Notice of Disagreement include: (1) Removal of the requirement to provide a social security number; (2) inclusion of checkboxes to indicate a preferred method of hearing; (3) inclusion of a checkbox to indicate whether the decision for which appeal is being sought was issued by the Veterans Health Administration (VHA); (4) inclusion of a checkbox to request an extension of the deadline to file a Notice of Disagreement; (5) removal of the checkbox used to indicate whether the Notice of Disagreement has been filed in response to a Statement of the Case or Supplemental Statement of the Case issued under the legacy appeals process; (6) replacement of the checkbox for

indicating the claimant ''is homeless'' to indicate whether the claimant is ''experiencing homelessness''; (7) a clarified description of the window of time within which to submit evidence on the Evidence Submission docket; and (8) adding a subpart to Part III for issues the appellant wishes to include in the VA Form 10182 that need to be listed on additional sheets. Proposed revisions also include updated instructions for completing the Notice of Disagreement.

There is a decrease in the respondent burden because the associated control number originally included the nonstandard legacy Notice of Disagreement. Consistent with the wind-down of legacy appeals following implementation of the AMA, the Board is not seeking renewal of the nonstandard legacy Notice of Disagreement under this control number.

Affected Public: Individuals and households.

Estimated Annual Burden: 64,805 hours.

Estimated Average Burden per Respondent: 37 minutes.

Frequency of Response: Once.

Estimated Number of Respondents: 126,000.

By direction of the Secretary.

Maribel Aponte,

VA PRA Clearance Officer, Office of Enterprise and Integration/Data Governance Analytics, Department of Veterans Affairs.

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Environmental Protection Agency

40 CFR Part 60

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

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2021–0317; FRL–8510–02–OAR]

RIN 2060–AV16

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This document comprises three distinct groups of actions under the Clean Air Act (CAA) which are collectively intended to significantly reduce emissions of greenhouse gases (GHGs) and other harmful air pollutants from the Crude Oil and Natural Gas source category. First, the EPA proposes to revise the new source performance standards (NSPS) for GHGs and volatile organic compounds (VOCs) for the Crude Oil and Natural Gas source category under the CAA to reflect the Agency's most recent review of the feasibility and cost of reducing emissions from these sources. Second, the EPA proposes emissions guidelines (EG) under the CAA, for states to follow in developing, submitting, and implementing state plans to establish performance standards to limit GHGs from existing sources (designated facilities) in the Crude Oil and Natural Gas source category. Third, the EPA is taking several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021 under the Congressional Review Act (CRA), disapproving the EPA's final rule titled, ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,'' Sept. 14, 2020 (''2020 Policy Rule''). This proposal responds to the President's January 20, 2021, Executive order (E.O.) titled ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,'' which directed the EPA to consider taking the actions proposed here.

DATES:

Comments. Comments must be received on or before January 14, 2022. 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 December 15, 2021.

Public hearing: The EPA will hold a virtual public hearing on November 30, 2021 and December 1, 2021. See **SUPPLEMENTARY INFORMATION** for information on the hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2021–0317 by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov/* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2021–0317 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2021–0317.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2021–0317, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov/,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the ''Public Participation'' heading of the **SUPPLEMENTARY INFORMATION** section of this document. Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are closed to the public, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. We encourage the public to submit comments via *https://www.regulations.gov/* or email, as there may be a delay in processing mail and faxes. Hand deliveries and couriers may be received by scheduled appointment only. For further information on EPA Docket Center services and the current status, please visit us online at *https://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Karen Marsh, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–1065; fax number: (919) 541–0516; and email address: *marsh.karen@epa.gov* or 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.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. Please note that the EPA is deviating from its typical approach for public hearings, because the President has declared a national emergency. Due to the current Centers for Disease Control and Prevention (CDC) recommendations, as well as state and local orders for social distancing to limit the spread of COVID–19, the EPA cannot hold in-person public meetings at this time.

The public hearing will be held via virtual platform on November 30, 2021, and December 1, 2021, and will convene at 11:00 a.m. Eastern Time (ET) and conclude at 9:00 p.m. ET each day. On each hearing day, the EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.* If the EPA receives a high volume of registrations for the public hearing, we may continue the public hearing on December 2, 2021. The EPA does not intend to publish a document in the **Federal Register** announcing the potential addition of a third day for the public hearing or any other updates to the information on the hearing described in this document. Please monitor *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry* for any updates to the information described in this document, including information about the public hearing. For information or questions about the public hearing, please contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.*

The EPA will begin pre-registering speakers for the hearing upon publication of this document in the **Federal Register**. The EPA will accept registrations on an individual basis. To register to speak at the virtual hearing, follow the directions at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry* or contact the public hearing team at (888) 372–

8699 or by email at *SPPDpublichearing@epa.gov.* The last day to pre-register to speak at the hearing will be November 24, 2021. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.*

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

Each commenter will have 5 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email) by emailing it to *marsh.karen@epa.gov* and *hambrick.amy@epa.gov.* The EPA also recommends submitting the text of your oral testimony as written comments to the rulemaking docket.

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

If you require the services of an interpreter or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by November 22, 2021. The EPA may not be able to arrange accommodations without advanced notice.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2021–0317. All documents in the docket are listed in *https://www.regulations.gov/.* Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. With the exception of such material, publicly available docket materials are available electronically in *https://www.regulations.gov/.*

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2021–0317. 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 *https://www.regulations.gov/,* including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *https://www.regulations.gov/* or email. This type of information should be submitted by mail as discussed below.

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

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

The EPA is temporarily suspending its Docket Center and Reading Room for public visitors, with limited exceptions, to reduce the risk of transmitting COVID–19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. We encourage the public to submit comments via *https://www.regulations.gov/* as there may be a delay in processing mail and faxes. Hand deliveries or couriers will be received by scheduled appointment only. For further information and updates on EPA Docket Center services, please visit us online at *https://www.epa.gov/dockets.*

The EPA continues to carefully and continuously monitor information from the CDC, local area health departments, and our Federal partners so that we can respond rapidly as conditions change regarding COVID–19.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov/* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, mark the outside of the digital storage media as CBI and then identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* above. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2021–0317. Note that written comments containing CBI submitted by mail may be delayed and no hand deliveries will be accepted.

Preamble acronyms and abbreviations. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACE Affordable Clean Energy rule
AEO Annual Energy Outlook
AMEL alternate means of emissions limitation
ANGA American Natural Gas Alliance
ANSI American National Standards Institute
APCD air pollution control devices
API American Petroleum Institute
ARPA–E Advanced Research Projects Agency-Energy
ASME American Society of Mechanical Engineers

ASTM American Society for Testing and Materials
AVO audio, visual, olfactory
BACT best achievable control technology
BOEM Bureau of Ocean Energy Management
BLM Bureau of Land Management
BMP best management practices
boe barrels of oil equivalents
BSER best system of emission reduction
BTEX benzene, toluene, ethylbenzene, and xylenes
CAA Clean Air Act
CBI Confidential Business Information
CDC Center for Disease Control
CDX EPA's Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CH_4 methane
cm centimeter
CPI consumer price index
CPI–U consumer price index urban
CO carbon monoxide
COPD chronic obstructive pulmonary disease
CO_2 carbon dioxide
CO_2 Eq. carbon dioxide equivalent
COA condition of approval
COS carbonyl sulfide
CRA Congressional Review Act
CS_2 carbon disulfide
CVS closed vent systems
DC direct current
DOE Department of Energy
DOI Department of the Interior
DOT Department of Transportation
EAV equivalent annualized value
EDF Environmental Defense Fund
EG emission guidelines
ECOS Environmental Council of the States
EGU electricity generating units
EIA U.S. Energy Information Administration
EJ environmental justice
EO Executive Order
EPA Environmental Protection Agency
ERT Electronic Reporting Tool
FERC The U.S. Federal Energy Regulatory Commission
fpm feet per minute
GC gas chromatograph
GHGs greenhouse gases
GHGI Inventory of U.S. Greenhouse Gas Emissions and Sinks
GHGRP Greenhouse Gas Reporting Program
GRI Gas Research Institute
GWP global warning potential
HAP hazardous air pollutant(s)
HC hydrocarbons
HFC hydrofluorocarbons
H_2S hydrogen sulfide
ICR Information Collection Request
IOGCC Interstate Oil and Gas Compact Commission
IPCC Intergovernmental Panel on Climate Change
IR infrared
IRFA initial regulatory flexibility analysis
kt kilotons
kg kilograms
low-e low emission
LDAR leak detection and repair
Mcf thousand cubic feet
MMT million metric tons
MRR monitoring, recordkeeping, and reporting
MW megawatt
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NCA4 2017–2018 Fourth National Climate Assessment
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NGL natural gas liquid
NGO non-governmental organization
NOAA National Oceanic and Atmospheric Administration
NO_X nitrogen oxides
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OCSLA The Outer Continental Shelf Lands Act
OAQPS Office of Air Quality Planning and Standards
OIG Office of the Inspector General
OGI optical gas imaging
OMB Office of Management and Budget
PE professional engineer
PFCs perfluorocarbons
PHMSA Pipeline and Hazardous Materials Safety Administration
PM particulate matter
$PM_{2.5}$ PM with a diameter of 2.5 micrometers or less
ppb parts per billion
ppm parts per million
PRA Paperwork Reduction Act
PRD pressure release device
PRV pressure release valve
PSD Prevention of Significant Deterioration
psig pounds per square inch gauge
PTE potential to emit
PV present value
REC reduced emissions completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RTC response to comments
SBAR Small Business Advocacy Review
SC-CH_4 social cost of methane
SCF significant contribution finding
scf standard cubic feet
scfh standard cubic feet per hour
scfm standard cubic feet per minute
SF_6 sulfur hexafluoride
SIP State Implementation Plan
SO_2 sulfur dioxide
SO_X sulfur oxides
tpy tons per year
D.C. Circuit U.S. Court of Appeals for the District of Columbia Circuit
TAR Tribal Authority Rule
TIP Tribal Implementation Plan
TSD technical support document
TTN Technology Transfer Network
UAS unmanned aircraft systems
UIC underground injection control
UMRA Unfunded Mandates Reform Act
U.S. United States
USGCRP U.S. Global Change Research Program
USGS U.S. Geologic Survey
VCS Voluntary Consensus Standards
VOC volatile organic compounds
VRD vapor recovery device
VRU vapor recovery unit

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I. Executive Summary

A. Purpose of the Regulatory Action

This proposed rulemaking takes a significant step forward in mitigating climate-destabilizing pollution and protecting human health by reducing GHG and VOC emissions from the Oil and Natural Gas Industry,[1] specifically the Crude Oil and Natural Gas source category.[2] The Oil and Natural Gas Industry is the United States' largest industrial emitter of methane, a highly potent GHG. Human activity-related emissions of methane are responsible for about one third of the warming due to well-mixed GHGs and constitute the second most important warming agent arising from human activity after carbon dioxide (a well-mixed gas is one with an atmospheric lifetime longer than a year or two, which allows the gas to be mixed around the world, meaning that the location of emission of the gas has little importance in terms of its impacts). According to the Intergovernmental Panel on Climate Change (IPCC), strong, rapid, and sustained methane reductions are critical to reducing near-term disruption of the climate system and are a vital complement to reductions in other GHGs that are needed to limit the long-term extent of climate change and its destructive impacts. The Oil and Natural Gas Industry also emits other harmful pollutants in varying concentrations and amounts, including carbon dioxide (CO_2), VOC, sulfur dioxide (SO_2), nitrogen oxide (NO_X), hydrogen sulfide (H_2S), carbon disulfide (CS_2), and carbonyl sulfide (COS), as well as benzene, toluene, ethylbenzene, and xylenes (this group is commonly referred to as ''BTEX''), and n-hexane.

Under the authority of CAA section 111, this rulemaking proposes comprehensive standards of performance for GHG emissions (in the form of methane limitations) and VOC emissions for new, modified, and reconstructed sources in the Crude Oil and Natural Gas source category, including the production, processing, transmission and storage segments. For designated facilities,[3] this rulemaking proposes EG containing presumptive standards for GHG in the form of methane limitations. When finalized, States shall utilize these EG to submit to the EPA plans that establish standards of performance for designated facilities and provide for implementation and enforcement of such standards. The EPA will provide support for States in developing their plans to reduce methane emissions from designated facilities within the Crude Oil and Natural Gas source category.

The EPA is proposing these actions in accordance with its legal obligations and authorities following a review directed by E.O. 13990, ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,'' issued on January 20, 2021. The EPA intends for these proposed actions to address the far-reaching harmful consequences and real economic costs of climate change. According to the IPCC AR6 assessment, ''It is unequivocal that human influence has warmed the atmosphere, ocean and land. Widespread and rapid changes in the atmosphere, ocean, cryosphere and biosphere have occurred.'' The IPCC AR6 assessment states these changes have led to increases in heat waves and wildfire weather, reductions in air quality, more intense hurricanes and

[1] The EPA characterizes the Oil and Natural Gas Industry operations as being generally composed of four segments: (1) Extraction and production of crude oil and natural gas (''oil and natural gas production''), (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution.

[2] The EPA defines the Crude Oil and Natural Gas source category to mean (1) crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station. For purposes of this proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate''.

[3] The term ''designated facility'' means ''any existing facility which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility.'' See 40 CFR 60.21a(b).

rainfall events, and rising sea level. These changes, along with future projected changes, endanger the physical survival, health, economic well-being, and quality of life of people living in the United States (U.S.), especially those in the most vulnerable communities.

Methane is both the main component of natural gas and a potent GHG. One ton of methane in the atmosphere has 80 times the warming impact of a ton of CO_2, and contributes to the creation of ground-level ozone which is another greenhouse gas. Because methane has a shorter lifetime than CO_2, it has a smaller relative impact—although still significantly greater than CO_2—when considering longer time periods. One standard metric is the 100-year global warming potential (GWP), which is a measure of the climate impact of emissions of one ton a greenhouse gas over 100 years relative to the impact of the emissions of one ton of CO_2. Even over this long timeframe, methane has a 100-year GWP of almost 30. The IPCC AR6 assessment found that ''Over time scales of 10 to 20 years, the global temperature response to a year's worth of current emissions of SLCFs (short lived climate forcer) is at least as large as that due to a year's worth of CO_2 emissions.'' [4] The IPCC estimated that, depending on the reference scenario, collective reductions in these SLCFs (methane, ozone precursors, and HFCs) could reduce warming by 0.2 degrees Celsius (°C) (more than one-third of a degree Fahrenheit (°F) in 2040 and 0.8 °C (almost 1.5 °F) by the end of the century, which is important in the context of keeping warming to well below 2 °C (3.6 °F). As methane is the most important SLCF, this makes methane mitigation one of the best opportunities for reducing near term warming. Emissions from human activities have already more than doubled atmospheric methane concentrations since 1750, and that concentration has been growing larger at record rates in recent years.[5] In the absence of additional reduction policies, methane emissions are projected to continue rising through at least 2040.

Methane's radiative efficiency means that immediate reductions in methane emissions, including from sources in the Crude Oil and Natural Gas source category, can help reduce near-term warming. As natural gas is comprised primarily of methane, every natural gas leak, or intentional release of natural gas through venting or other processes, constitutes a release of methane. Reducing human-caused methane emissions, such as controlling natural gas leaks and releases as proposed in these actions, would contribute substantially to global efforts to limit temperature rise, aiding efforts to remain well below 2 °C above pre-industrial levels. See preamble section III for further discussion on the Crude Oil and Natural Gas Emissions and Climate Change, including discussion of the GHGs, VOCs, and SO_2 Emissions on Public Health and Welfare.

Methane and VOC emissions from the Crude Oil and Natural Gas source category result from a variety of industry operations across the supply chain. As natural gas moves through the necessarily interconnected system of exploration, production, storage, processing, and transmission that brings it from wellhead to commerce, emissions primarily result from intentional venting, unintentional gas carry-through (*e.g.,* vortexing from separator drain, improper liquid level settings, liquid level control valve on an upstream separator or scrubber does not seat properly at the end of an automated liquid dumping event, inefficient separation of gas and liquid phases occurs upstream of tanks allowing some gas carry-through), routine maintenance, unintentional fugitive emissions, flaring, malfunctions, abnormal process conditions, and system upsets. These emissions are associated with a range of specific equipment and practices, including leaking valves, connectors, and other components at well sites and compressor stations; leaks and vented emissions from storage vessels; releases from natural gas-driven pneumatic pumps and controllers; liquids unloading at well sites; and venting or under-performing flaring of associated gas from oil wells. But technical innovations have produced a range of technologies and best practices to monitor, eliminate or minimize these emissions, which in many cases have the benefit of reducing multiple pollutants at once and recovering saleable product. These technologies and best practices have been deployed by individual oil and natural gas companies, required by State regulations, or reflected in regulations issued by the EPA and other Federal agencies.

In this action, the EPA has taken a comprehensive analysis of the available data from emission sources in the Crude Oil and Natural Gas source category and the latest available information on control measures and techniques to identify achievable, cost-effective measures to significantly reduce emissions, consistent with the requirements of section 111 of the CAA. If finalized and implemented, the actions proposed in this rulemaking would lead to significant and cost-effective reductions in climate and health-harming pollution and encourage development and deployment of innovative technologies to further reduce this pollution in the Crude Oil and Natural Gas source category. The actions proposed in this rulemaking would:

- Update, strengthen, and expand current requirements under CAA section 111(b) for methane and VOC emissions from new, modified, and reconstructed facilities,
- establish new limits for methane, and VOC emissions from new, modified, and reconstructed facilities that are not currently regulated under CAA section 111(b),
- establish the first nationwide EG for States to limit methane pollution from existing designated facilities in the source category under CAA section 111(d), and
- take comment on additional sources of pollution that, with understanding gained from more information, may offer opportunities for emission reductions, which the EPA would present in a supplemental rulemaking proposal under both CAA section 111(b) and (d).

In developing this proposal, the EPA drew on its own prior experience in regulating sources in the Crude Oil and Natural Gas source category under section 111 and other CAA programs; applied lessons learned from States' regulatory efforts, the emission reduction efforts of leading companies, and the EPA's long-standing voluntary emission reduction programs; and reviewed the latest available information about new and developing technologies, as well as, peer-reviewed research from emission measurement campaigns across the U.S. Further, the EPA undertook extensive pre-proposal outreach to the public and to stakeholders, including three full days

[4] However, the IPCC AR6 assessment cautioned that ''The effects of the SLCFs decay rapidly over the first few decades after pulse emission. Consequently, on time scales longer than about 30 years, the net long-term temperature effects of sectors and regions are dominated by CO_2.''

[5] Naik, V., S. Szopa, B. Adhikary, P. Artaxo, T. Berntsen, W.D. Collins, S. Fuzzi, L. Gallardo, A. Kiendler 41 Scharr, Z. Klimont, H. Liao, N. Unger, P. Zanis, 2021, Short-Lived Climate Forcers. In: Climate Change 42 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the 43 Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. 44 Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. 45 Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu and B. Zhou (eds.)]. Cambridge University 46 Press. In Press.

of public listening sessions, roundtables with State energy and environmental regulators, a two-day workshop on innovative methane detection technologies, and a nonregulatory docket established in May 2021 to receive written comments. Through this outreach, the EPA heard from diverse voices and perspectives including State and local governments, Tribal nations, communities affected by oil and gas pollution, environmental and public health organizations, and representatives of the oil and natural gas industry, all of which provided ideas and information that helped shape and inform this proposal.

The EPA also considered community and environmental justice implications in the development of this proposal and sought to ensure equitable treatment and meaningful involvement of all people regardless of race, color, national origin, or income in the process. The EPA engaged and consulted representatives of frontline communities that are directly affected by and particularly vulnerable to the climate and health impacts of pollution from this source category through interactions such as webinars, listening sessions and meetings. These opportunities allowed the EPA to hear directly from the public, especially overburdened and underserved communities, on the development of the proposed rule and to factor these concerns into this proposal. For example, in addition to establishing EG that extend fugitive emission requirements to existing oil and natural gas facilities, the EPA is proposing to expand leak detection programs already in effect for new sources to include known sources of large emission events and proposing to require more frequent monitoring at sites with more emissions. The EPA is also taking comment on innovative mechanisms to ensure compliance and minimize emissions, including the possibility of providing a pathway for communities to detect and report large emitting events that may require follow-up and mitigation by owners and operators. The extensive pollution reduction measures in this proposal, if finalized, would collectively reduce a suite of harmful pollutants and their associated health impacts in communities adjacent to these emission sources. Further, to help ensure that the needs and perspectives of communities with environmental justice concerns are considered as States develop plans to establish and implement standards of performance for existing sources, the EPA is proposing to require that States demonstrate they have undertaken meaningful outreach and engagement with overburdened and underserved communities as part of their State plan submissions under the EPA. A full discussion of the Environmental Justice Considerations, Implications, and Stakeholder Outreach can be found in section VI of the preamble. A full discussion of Other Stakeholder Outreach is found in section VII of the preamble.

As described in more detail below, the EPA recognizes that several States and other Federal agencies currently regulate the Oil and Natural Gas Industry. The EPA also recognizes that these State and other Federal agency regulatory programs have matured since the EPA began implementing the current NSPS requirements in 2012 and 2016. The EPA further acknowledges the technical innovations that the Oil and Natural Gas Industry has made during the past decade; this industry operates at a fast pace and changes constantly as technology evolves. The EPA commends these efforts and recognizes States for their innovative standards, alternative compliance options, and implementation strategies, and intends these proposed actions to build upon progress made by certain States and Federal agencies in reducing GHG and VOC emissions. See preamble section V for fuller discussion of Related State Actions and Other Federal Actions Regulating Oil and Natural Gas Sources and Industry and Voluntary Actions to Address Climate Change.

The EPA believes that a broad ensemble of mutually leveraging efforts across all States and all Federal agencies is essential to meaningfully address climate change effectively. As the Federal agency with primary responsibility to protect human health and the environment, the EPA has the unique responsibility and authority to regulate harmful air pollutants emitted by the Crude Oil and Natural Gas source category. The EPA recognizes that States and other Federal agencies regulate in accordance with their respective legal authorities and within their respective jurisdictions but collectively do not fully and consistently address the range of sources and emission reduction measures contained in this proposal. Direct Federal regulation of methane from new, reconstructed, and modified sources in this category, combined with approved State plans that are consistent with the EPA's presumptive standards for designated facilities (existing sources), will help reduce both climate- and other health-harming pollution from a large number of sources that are either unregulated or from which additional, cost-effective reductions are available, level the regulatory playing field, and help promote technological innovation.

Throughout this action, unless noted otherwise, the EPA is requesting comments on all aspects of the proposal to enable the EPA to develop a final rule that, consistent with our responsibilities under section 111 of the CAA, achieves the greatest possible reductions in methane and VOC emissions while remaining achievable, cost effective, and conducive to technological innovation. As a further step in the rulemaking process and to solicit additional public input, the EPA plans to issue a supplemental proposal and supplemental RIA for the supplemental proposal to provide regulatory text for the proposed NSPS OOOOb and EG OOOOc. In light of certain innovative elements of this proposed rule and the EPA's request for information that would support the regulation of additional sources in the Crude Oil and Natural Gas source category as part of this rulemaking, the EPA is considering including additional provisions in this supplemental proposal and RIA based on information and comment collected in response to this document.

As noted later in this preamble, the supplemental proposal may address, among other issues: (1) Ways to mitigate methane from abandoned wells, (2) measures to reduce emissions from pipeline pigging operations and other pipeline blowdowns, (3) ways to minimize emissions from tank truck loading operations, and (4) ways to strengthen requirements to ensure proper operation and optimal performance of control devices. In addition, and as noted in the solicitations of comment in this document, the supplemental proposal may revisit and refine certain provisions of this proposal in response to information provided by the public. For instance, the EPA is seeking input on multiple aspects of the proposed approach for fugitive emissions monitoring at well sites, including the baseline emission threshold and other criteria (such as the presence of specific types of malfunction-prone equipment) that should be used to determine whether a well site is required to undertake ongoing fugitive emissions monitoring; the methodology for calculating baseline methane emissions and whether it should account for malfunctions or improper operation of controls at storage vessels; and ways to ensure that emissions from wells owned by small businesses are addressed while still recognizing the greater challenges that small businesses with less dedicated staff and resources for

environmental compliance may have. The EPA is also seeking input on ways to ensure that captured associated gas is collected for a useful purpose rather than flared, and the feasibility of requiring broader use of zero-emitting technology for pneumatic pumps.

Finally, the EPA is seeking comment and information on alternative measurement technologies, which we are proposing to allow in the rule. We have heard strong interest from various stakeholders on employing new tools for methane identification and quantification, particularly for large emission sources (commonly known as ''super-emitters''). Information provided in response to this proposal may be used to evaluate whether a change in BSER from the proposed quarterly OGI monitoring to a monitoring program using alternative measurement technologies is appropriate. Separate from the role of these alternative measurement technologies in a regulatory monitoring program, we are also soliciting comment on ways to structure a pathway for communities to identify large emission events which owners or operators would then be required to investigate, and mechanisms for the collection and public dissemination of this information, for possible further development as part of a supplemental proposal.

This preamble includes comment solicitations/requests on several topics and issues. We have prepared a separate memorandum that presents these comment requests by section and topic as a guide to assist commenters in preparing comments. This memorandum can be obtained from the Docket for this action (see Docket ID No. EPA–HQ–OAR–2021–0317). The title of the memorandum is ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review—Proposed Rule Summary of Comment Solicitations.''

B. Summary of the Major Provisions of This Regulatory Action

This proposed rulemaking includes three distinct groups of actions under the CAA that are each severable from the other. First, pursuant to CAA 111(b)(1)(B), the EPA has reviewed, and is proposing revisions to, the standards of performance for the Crude Oil and Natural Gas source category published in 2016 and amended in 2020, codified at 40 CFR part 60, subpart OOOOa—*Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015* (2016 NSPS OOOOa). Specifically, the EPA is proposing to update, strengthen, and expand the current requirements under CAA section 111(b) for methane and VOC emissions from sources that commenced construction, modification, or reconstruction after November 15, 2021. These proposed standards of performance will be in a new subpart, 40 CFR part 60, subpart OOOOb (NSPS OOOOb), and include standards for emission sources previously not regulated under the 2016 NSPS OOOOa.

Second, pursuant to CAA 111(d), the EPA is proposing the first nationwide EG for States to limit methane pollution from designated facilities in the Crude Oil and Natural Gas source category. The EG being proposed in this rulemaking will be in a new subpart, 40 CFR part 60, subpart OOOOc (EG OOOOc). The EG are designed to inform States in the development, submittal, and implementation of State plans that are required to establish standards of performance for GHGs from their designated facilities in the Crude Oil and Natural Gas source category.

Third, the EPA is taking several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021 under the CRA, disapproving the EPA's final rule titled, ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,'' 85 FR 57018 (Sept. 14, 2020) (''2020 Policy Rule''). As explained in Section X of this action (Summary of Proposed Action for NSPS OOOOa), the EPA is proposing amendments to the 2016 NSPS OOOOa to address (1) certain inconsistencies between the VOC and methane standards resulting from the disapproval of the 2020 Policy Rule, and (2) certain determinations made in the final rule titled ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration,'' 85 FR 57398 (September 15, 2020) (2020 Technical Rule), specifically with respect to fugitive emissions monitoring at low production well sites and gathering and boosting stations. With respect to the latter, as described below, the EPA is proposing to rescind provisions of the 2020 Technical Rule that were not supported by the record for that rule, or by our subsequent information and analysis. The regulatory text for these proposed amendments is included in the docket for this rulemaking at Docket ID EPA–HQ–OAR–2021–0317.

In addition, in the final rule for this action, the EPA will update the NSPS OOOO and NSPS OOOOa provisions in the Code of Federal Regulations (CFR) to reflect the Congressional Review Act (CRA) resolution's disapproval of the final 2020 Policy Rule, specifically, the reinstatement of the NSPS OOOO and NSPS OOOOa requirements that the 2020 Policy Rule repealed but that came back into effect immediately upon enactment of the CRA resolution. It should be noted that these requirements have come back into effect already even though the EPA has not yet updated the CFR text to reflect them.[6] These updates to the CFR text are also included in the docket for this rulemaking at Docket ID EPA–HQ–OAR–2021–0317 for public awareness, but the EPA is not soliciting comment on them as they merely reflect current law. Under 5 U.S.C. 553(b)(3)(B), notice and comment is not required ''when the agency for good cause finds . . . that notice and public procedure thereon are . . . unnecessary . . . ,''[7] and, as just noted, notice and comment is not necessary for these updates. The EPA is waiting to make these updates to the CFR text until the final rule simply because it would be more efficient and clearer to amend the CFR once at the end of this rulemaking process to account for all changes to the 2012 NSPS OOOO (77 FR 49490, August 16, 2012) and 2016 NSPS OOOOa at the same time.

As CAA section 111(a)(1) requires, the standards of performance being proposed in this action reflect ''the degree of emission limitation achievable through the application of the best system of emission reduction [BSER] which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' This action further proposes EG for designated facilities, under which States must submit plans which establish standards of performance that reflect the degree of emission limitation achievable through application of the BSER, as identified in the final EG. In this proposed rulemaking, we evaluated potential control measures available for the affected facilities, the emission reductions achievable through these measures, and employed multiple approaches to evaluate the reasonableness of control costs associated with the options under

[6] See Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule Questions and Answers (June 30, 2021) available at *https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.*

[7] 5 U.S.C. 553(b)(3)(B) is applicable to rules promulgated under CAA section 111(b), under CAA section 307(d)(1) (flush language at end).

consideration. For example, in evaluating controls for reducing VOC and methane emissions from new sources, we considered a control measure's cost-effectiveness under both a ''single pollutant cost-effectiveness'' approach and a ''multipollutant cost-effectiveness'' approach, to appropriately consider that the systems of emission reduction considered in this rule typically achieve reductions in multiple pollutants at once and secure a multiplicity of climate and public health benefits. For a detailed discussion of the EPA's consideration of this and other BSER statutory elements, please see sections IV and IX of this preamble.

TABLE 1—APPLICABILITY DATES FOR PROPOSED SUBPARTS ADDRESSED IN THIS PROPOSED ACTION

Subpart	Source type	Applicable dates
40 CFR part 60, subpart OOOO	New, modified, or reconstructed sources	After August 23, 2011 and on or before September 18, 2015.
40 CFR part 60, subpart OOOOa	New, modified, or reconstructed sources	After September 18, 2015 and on or before November 15, 2021.
40 CFR part 60, subpart OOOOb	New, modified, or reconstructed sources	After November 15, 2021.
40 CFR part 60, subpart OOOOc	Existing sources	On or before November 15, 2021.

1. Proposed Standards for New, Modified and Reconstructed Sources After November 15, 2021 (Proposed NSPS OOOOb)

As described in sections XI and XII of this preamble, under the authority of CAA section 111(b)(1)(B) the EPA has reviewed the VOC, GHG (in the form of limitations on methane), and SO_2 standards in the 2016 NSPS OOOOa (as amended in 2020 by the Technical Rule). Based on its review, the EPA is proposing revisions to the standards for certain emissions sources to reflect the updated BSER for those affected sources. Where our analyses show that the BSER for an affected source remains the same, the EPA is proposing to retain the current standard for that affected source. In addition, the EPA is proposing methane and VOC standards for several new sources that are currently unregulated. The proposed NSPS described above would apply to new, modified, and reconstructed emission sources across the Crude Oil and Natural Gas source category, including the production, processing, transmission, and storage segments, for which construction, reconstruction, or modification commenced after November 15, 2021, which is the date of publication of the proposed revisions to the NSPS. In particular, this action proposes to retain the 2016 NSPS OOOOa SO_2 performance standard for sweetening units and the 2016 OOOOa VOC and methane performance standards for well completions and centrifugal compressors; proposes revisions to strengthen the 2016 NSPS OOOOa VOC and methane standards addressing fugitive emissions from well sites and compressor stations, storage vessels, pneumatic controllers, reciprocating compressors, pneumatic pumps, and equipment leaks at natural gas processing plants; and proposes new VOC and methane standards for well liquids unloading operations and intermittent vent pneumatic controllers, and oil wells with associated gas previously not regulated in the 2016 NSPS OOOOa. A summary of the proposed BSER determination and proposed NSPS for new, modified, and reconstructed sources (NSPS OOOOb) is presented in Table 2. See sections XI and XII of this preamble for a complete discussion of BSER determination and proposed NSPS requirements.

This proposal also solicits certain information relevant to the potential identification of additional emissions sources as affected facilities. Specifically, the EPA is evaluating the potential for establishing standards for abandoned and unplugged wells, blowdown emissions associated with pipeline pig launchers and receivers, and tank truck loading operations. While the EPA has assessed these sources based on currently available information, we have determined that we need additional information to evaluate BSER and to propose NSPS for these emissions sources. A full discussion of the solicitation for comment regarding these additional emission sources is found in section XIII of the preamble.

2. Proposed EG for Sources Constructed Prior to November 15, 2021 (Proposed EG OOOOc)

As described in sections XI and XII of this preamble, under the authority of CAA section 111(d), the EPA is proposing the first nationwide EG for GHG (in the form of methane limitations) for the Crude Oil and Natural Gas source category, including the production, processing, transmission, and storage segments (EG OOOOc). When the EPA establishes NSPS for a source category, the EPA is required to issue EG to reduce emissions of certain pollutants from existing sources in that same source category. In such circumstances, under CAA section 111(d), the EPA must issue regulations to establish procedures under which States submit plans to establish, implement, and enforce standards of performance for existing sources for certain air pollutants to which a Federal NSPS would apply if such existing source were a new source. Thus, the issuance of CAA section 111(d) final EG does not impose binding requirements directly on sources but instead provides requirements for states in developing their plans. Although State plans bear the obligation to establish standards of performance, under CAA sections 111(a)(1) and 111(d), those standards of performance must reflect the degree of emission limitation achievable through the application of the BSER as determined by the Administrator. As provided in section 111(d), a State may choose to take into account remaining useful life and other factors in applying a standard of performance to a particular source, consistent with the CAA, the EPA's implementing regulations, and the final EG.

In this action, the EPA is proposing BSER determinations and the degree of limitation achievable through application of the BSER for certain existing equipment, processes, and activities across the Crude Oil and Natural Gas source category. Section XIV of this preamble discusses the components of EG, including the steps, requirements, and considerations associated with the development, submittal, and implementation of State, Tribal, and Federal plans, as appropriate. For the EG, the EPA is proposing to translate the degree of emission limitation achievable through application of the BSER (*i.e.,* level of stringency) into presumptive standards that States may use in the development of State plans for specific designated facilities. By doing this, the EPA has formatted the proposed EG such that if a State chooses to adopt these

presumptive standards, once finalized, as the standards of performance in a State plan, the EPA could approve such a plan as meeting the requirements of CAA section 111(d) and the finalized EG, if the plan meets all other applicable requirements. In this way, the presumptive standards included in the EG serve a function similar to that of a model rule,[8] because they are intended to assist States in developing their plan submissions by providing States with a starting point for standards that are based on general industry parameters and assumptions. The EPA believes that providing these presumptive standards will create a streamlined approach for States in developing plans and the EPA in evaluating State plans. However, the EPA's action on each State plan submission is carried out via rulemaking, which includes public notice and comment. Inclusion of presumptive standards in the EG does not seek to pre-determine the outcomes of any future rulemaking.

Designated facilities located in Indian country would not be encompassed within a State's CAA section 111(d) plan. Instead, an eligible Tribe that has one or more designated facilities located in its area of Indian country would have the opportunity, but not the obligation, to seek authority and submit a plan that establishes standards of performance for those facilities on its Tribal lands. If a Tribe does not submit a plan, or if the EPA does not approve a Tribe's plan, then the EPA has the authority to establish a Federal plan for that Tribe. A summary of the proposed EG for existing sources (EG OOOOc) for the oil and natural gas sector is presented in Table 3. See sections XI and XII of this preamble for a complete discussion of the proposed EG requirements.

As discussed above for the proposed NSPS OOOOb, the EPA is considering including additional sources as affected facilities in a potential future supplemental rulemaking proposal[9] under CAA section 111(b). The EPA is also considering including these additional sources as designated facilities under the EG in OOOOc in a potential future supplemental rulemaking proposal under CAA section 111(d). As with the proposed NSPS OOOOb, the EPA is evaluating the potential for establishing EG applicable to abandoned and unplugged wells, blowdown emissions associated with pipeline pig launchers and receivers, and tank truck loading operations (assuming the EPA establishes NSPS for these emissions points). As described in section XIII of this preamble, the EPA is soliciting information to assist in this effort.

3. Proposed Amendments to 2016 NSPS OOOOa, and CRA-Related CFR Updates

The EPA is also proposing certain modifications to the 2016 NSPS OOOOa to address certain amendments to the VOC standards for sources in the production and processing segments finalized in the 2020 Technical Rule. Because the methane standards for the production and processing segments and all standards for the transmission and storage segment were removed from the 2016 NSPS OOOOa via the 2020 Policy Rule prior to the finalization of the 2020 Technical Rule, the latter amendments apply only to the 2016 NSPS OOOOa VOC standards for the production and processing segments. In this proposed rulemaking, the EPA also is proposing to apply some of the 2020 Technical Rule amendments to the methane standards for all industry segments and to VOC standards for the transmission and storage segment in the 2016 NSPS OOOOa. These amendments are associated with the requirements for well completions, pneumatic pumps, closed vent systems, fugitive emissions, alternative means of emission limitation (AMELs), onshore natural gas processing plants, as well as other technical clarifications and corrections. The EPA also is proposing to repeal the amendments in the 2020 Technical Rule that (1) exempted low production well sites from monitoring fugitive emissions and (2) changed monitoring of VOC emissions at gathering and boosting compressor stations from quarterly to semiannual, which currently apply only to VOC standards (not methane standards) from the production and processing segments. A summary of the proposed amendments to the 2016 OOOOa NSPS is presented in section X of this preamble.

Lastly, in the final rule for this action, the EPA will update the NSPS OOOO and OOOOa provisions in the CFR to reflect the CRA resolution's disapproval of the final 2020 Policy Rule, specifically, the reinstatement of the OOOO and OOOOa requirements that the 2020 Policy Rule repealed but that came back into effect immediately upon enactment of the CRA resolution. The EPA is waiting to make the updates to the CFR text until the final rule simply because it would be more efficient and clearer to amend the CFR once at the end of this rulemaking process to account for all changes to the 2012 NSPS OOOO and 2016 NSPS OOOOa at the same time. In accordance with 5 U.S.C. 553(b)(3)(B), the EPA is not soliciting comment on these updates.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGS AND VOC

[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
Fugitive Emissions: Well Sites with Baseline Emissions >0 to <3 tpy[1] Methane.	Demonstrate actual site emissions are reflected in calculation.	Perform survey to verify that actual site emissions are reflected in calculation.
Fugitive Emissions: Well Sites ≥3 tpy Methane.	Monitoring and repair based on quarterly monitoring using OGI[2].	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
(Co-proposal) Fugitive Emissions: Well Sites with Baseline Emissions ≥3 to <8 tpy Methane.	Monitoring and repair based on semiannual monitoring using OGI.	Semiannual OGI monitoring following appendix K. (Optional semiannual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.

[8] The presumptive standards are not the same as a Federal plan under CAA section 111(d)(2). The EPA has an obligation to promulgate a Federal plan if a state fails to submit a satisfactory plan. In such circumstances, the final EG and presumptive standards would serve as a guide to the development of a Federal plan. See section XIV.F. for information on Federal plans.

[9] A supplemental proposal would include an updated RIA.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGS AND VOC—Continued

[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
(Co-proposal) Fugitive Emissions: Well Sites with Baseline Emissions ≥8 tpy Methane.	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm[3] defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Compressor Stations	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations on Alaska North Slope.	Monitoring and repair based on annual monitoring using OGI.	Annual OGI monitoring following appendix K. (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Screening, monitoring, and repair based on bimonthly screening using an advanced measurement technology and annual monitoring using OGI.	(Optional) Alternative bimonthly screening with advanced measurement technology with annual OGI monitoring following appendix K.
Storage Vessels: A Single Storage Vessel or Tank Battery with PTE[4] of 6 tpy or More of VOC.	Capture and route to a control device	95 percent reduction of VOC and methane.
Pneumatic Controllers: Natural Gas Driven that Vent to the Atmosphere.	Use of zero-emissions controllers	VOC and methane emission rate of zero.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas driven).	Installation of low-bleed pneumatic controllers.	Natural gas bleed rate no greater than 6 scfh.[5]
Pneumatic Controllers: Alaska (at sites where onsite power is not available—intermittent natural gas driven).	Monitor and repair through fugitive emissions program.	OGI monitoring and repair of emissions from controller malfunctions.
Well Liquids Unloading	Perform liquids unloading with zero methane or VOC emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting.	Each affected well that unloads liquids employ techniques or technology(ies) that eliminate or minimize venting of emissions during liquids unloading events to the maximum extent. Co Proposal Options: *Option One*—Affected facility would be defined as every well that undergoes liquids unloading. —If the method is one that does not result in any venting to the atmosphere, maintain records specifying the technology or technique and record instances where an unloading event results in emissions. —For unloading technologies or techniques that result in venting to the atmosphere, implement BMPs[6] to ensure that venting is minimized. —Maintain BMPs as records, and record instances when they were not followed. *Option Two*—Affected facility would be defined as every well that undergoes liquids unloading using a method that is not designed to eliminate venting. —Wells that utilize non-venting methods would not be affected facilities that are subject to the NSPS OOOOb. Therefore, they would not have requirements other than to maintain records to document that they used non-venting liquids unloading methods. —The requirements for wells that use methods that vent would be the same as described above under Option 1.
Wet Seal Centrifugal Compressors (except for those located at single well sites).	Capture and route emissions from the wet seal fluid degassing system to a control device or to a process.	Reduce emissions by 95 percent.
Reciprocating Compressors (except for those located at single well sites).	Replace the reciprocating compressor rod packing based on annual monitoring (when measured leak rate exceeds 2 scfm[7]) or route emissions to a process.	Replace the reciprocating compressor rod packing when measured leak rate exceeds 2 scfm based on the results of annual monitoring or collect and route emissions from the rod packing to a process through a closed vent system under negative pressure.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGS AND VOC—Continued

[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
Pneumatic Pumps: Natural Gas Processing Plants.	A natural gas emission rate of zero	A natural gas emission rate of zero from diaphragm and piston pneumatic pumps.
Pneumatic Pumps: Production Segment	Route diaphragm and piston pneumatic pumps to an existing control device or process.	95 percent control of diaphragm and piston pneumatic pumps 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.
Pneumatic Pumps: Transmission and Storage Segment.	Route diaphragm pneumatic pumps to an existing control device or process.	95 percent control of diaphragm pneumatic pumps 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.
Well Completions: Subcategory 1 (non-wildcat and non-delineation wells).	Combination of REC[8] and the use of a completion combustion device.	Applies to each well completion operation with hydraulic fracturing. 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, reinject 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 (and use) 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	Applies to each well completion operation with hydraulic fracturing. 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.
Equipment Leaks at Natural Gas Processing Plants.	LDAR[9] with bimonthly OGI	LDAR with OGI following procedures in appendix K.
Oil Wells with Associated Gas	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.
Sweetening Units	Achieve SO_2 emission reduction efficiency.	Achieve required minimum SO_2 emission reduction efficiency.

[1] tpy (tons per year).

[2] OGI (optical gas imaging).
[3] ppm (parts per million).
[4] PTE (potential to emit).
[5] scfh (standard cubic feet per hour).
[6] BMP (best management practices).
[7] scfm (standard cubic feet per minute).
[8] REC (reduced emissions completion).
[9] LDAR (leak detection and repair).

TABLE 3—SUMMARY OF PROPOSED BSER AND PROPOSED PRESUMPTIVE STANDARDS FOR GHGS FROM DESIGNATED FACILITIES

[EG OOOOc]

Designated facility	Proposed BSER	Proposed presumptive standards for GHGs
Fugitive Emissions: Well Sites >0 to <3 tpy Methane.	Demonstrate actual site emissions are reflected in calculation.	Perform survey to verify that actual site emissions are reflected in calculation.
Fugitive Emissions: Well Sites ≥3 tpy Methane.	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
(Co-proposal) Fugitive Emissions: Well Sites ≥3 to <8 tpy Methane.	Monitoring and repair based on semiannual monitoring using OGI.	Semiannual OGI monitoring following appendix K. (Optional semiannual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
(Co-proposal) Fugitive Emissions: Well Sites ≥8 tpy Methane.	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Compressor Stations	Monitoring and repair based on quarterly monitoring using OGI.	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations on Alaska North Slope.	Monitoring and repair based on annual monitoring using OGI.	Annual OGI monitoring following appendix K. (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Screening, monitoring, and repair based on bimonthly screening using an advanced measurement technology and annual monitoring using OGI.	(Optional) Alternative bimonthly screening with advanced measurement technology with annual OGI monitoring following appendix K.
Storage Vessels: Tank Battery with PTE of 20 tpy or More of Methane.	Capture and route to a control device	95 percent reduction of methane.
Pneumatic Controllers: Natural Gas Driven that Vent to the Atmosphere.	Use of zero-emissions controllers	VOC and methane emission rate of zero.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas driven).	Installation of low-bleed pneumatic controllers.	Natural gas bleed rate no greater than 6 scfh.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—intermittent natural gas driven).	Monitor and repair through fugitive emissions program.	OGI monitoring and repair of emissions from controller malfunctions.
Wet Seal Centrifugal Compressors (except for those located at single well sites).	Capture and route emissions from the wet seal fluid degassing system to a control device or to a process.	Reduce emissions by 95 percent.
Reciprocating Compressors (except for those located at single well sites).	Replace the reciprocating compressor rod packing based on annual monitoring (when measured leak rate exceeds 2 scfm) or route emissions to a process.	Replace the reciprocating compressor rod packing when measured leak rate exceeds 2 scfm based on the results of annual monitoring, or collect and route emissions from the rod packing to a process through a closed vent system under negative pressure.
Pneumatic Pumps: Natural Gas Processing Plants.	A natural gas emission rate of zero	Zero natural gas emissions from diaphragm and piston pneumatic pumps.
Pneumatic Pumps: Locations Other Than Natural Gas Processing Plants.	Route diaphragm pumps to an existing control device or process.	95 percent control of diaphragm pneumatic pumps 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.
Equipment Leaks at Natural Gas Processing Plants.	LDAR with bimonthly OGI	LDAR with OGI following procedures in appendix K.

TABLE 3—SUMMARY OF PROPOSED BSER AND PROPOSED PRESUMPTIVE STANDARDS FOR GHGS FROM DESIGNATED FACILITIES—Continued

[EG OOOOc]

Designated facility	Proposed BSER	Proposed presumptive standards for GHGs
Oil Wells with Associated Gas	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.

C. Costs and Benefits

To satisfy requirements of E.O. 12866, the EPA projected the emissions reductions, costs, and benefits that may result from this proposed action. These results are presented in detail in the regulatory impact analysis (RIA) accompanying this proposal developed in response to E.O. 12866. The RIA focuses on the elements of the proposed rule that are likely to result in quantifiable cost or emissions changes compared to a baseline without the proposal that incorporates changes to regulatory requirements induced by the CRA resolution. We estimated the cost, emissions, and benefit impacts for the 2023 to 2035 period. We present the present value (PV) and equivalent annual value (EAV) of costs, benefits, and net benefits of this action in 2019 dollars.

The initial analysis year in the RIA is 2023 as we assume the proposed rule will be finalized towards the end of 2022. The NSPS will take effect immediately and impact sources constructed after publication of the proposed rule. The EG will take longer to go into effect as States will need to develop implementation plans in response to the rule and have them approved by the EPA. We assume in the RIA that this process will take three years, and so EG impacts will begin in 2026. The final analysis year is 2035, which allows us to provide ten years of projected impacts after the EG is assumed to take effect.

The cost analysis presented in the RIA reflects a nationwide engineering analysis of compliance cost and emissions reductions, of which there are two main components. The first component is a set of representative or model plants for each regulated facility, segment, and control option. The characteristics of the model plant include typical equipment, operating characteristics, and representative factors including baseline emissions and the costs, emissions reductions, and product recovery resulting from each control option. The second component is a set of projections of activity data for affected facilities, distinguished by vintage, year, and other necessary attributes (*e.g.,* oil versus natural gas wells). Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a particular regulatory regime, multiplying activity data by model plant cost and emissions estimates, differencing from the baseline scenario, and then summing to the desired level of aggregation. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted in production or sold. Where applicable, we present projected compliance costs with and without the projected revenues from product recovery.

The EPA expects climate and health benefits due to the emissions reductions projected under this proposed rule. The EPA estimated the global social benefits of CH_4 emission reductions expected from this proposed rule using the SC-CH_4 estimates presented in the ''Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990 (IWG 2021)''. These SC-CH_4 estimates are interim values developed under E.O. 13990 for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available science and economics.

Under the proposed rule, the EPA expects that VOC emission reductions will improve air quality and are likely to improve health and welfare associated with exposure to ozone, $PM_{2.5}$, and HAP. Calculating ozone impacts from VOC emissions changes requires information about the spatial patterns in those emissions changes. In addition, the ozone health effects from the proposed rule will depend on the relative proximity of expected VOC and ozone changes to population. In this analysis, we have not characterized VOC emissions changes at a finer spatial resolution than the national total. In light of these uncertainties, we present an illustrative screening analysis in Appendix B of the RIA based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017 and do not include the results of this analysis in the estimate of benefits and net benefits projected from this proposal.

The projected national-level emissions reductions over the 2023 to 2035 period anticipated under the proposed requirements are presented in Table 4. Table 5 presents the PV and EAV of the projected benefits, costs, and net benefits over the 2023 to 2035 period under the proposed requirements using discount rates of 3 and 7 percent.

TABLE 4—PROJECTED EMISSIONS REDUCTIONS UNDER THE PROPOSED RULE, 2023–2035 TOTAL

Pollutant	Emissions reductions (2023–2035 total)
Methane (million short tons) [a]	41
VOC (million short tons)	12
Hazardous Air Pollutant (million short tons)	0.48

TABLE 4—PROJECTED EMISSIONS REDUCTIONS UNDER THE PROPOSED RULE, 2023–2035 TOTAL—Continued

Pollutant	Emissions reductions (2023–2035 total)
Methane (million metric tons CO_2 Eq.) [b]	920

[a] To convert from short tons to metric tons, multiply the short tons by 0.907. Alternatively, to convert metric tons to short tons, multiply metric tons by 1.102.
[b] CO_2 Eq. calculated using a global warming potential of 25.

TABLE 5—BENEFITS, COSTS, NET BENEFITS, AND EMISSIONS REDUCTIONS OF THE PROPOSED RULE, 2023 THROUGH 2035

[Dollar Estimates in Millions of 2019 Dollars] [a]

	3 percent discount rate		7 percent discount rate	
	Present value	Equivalent annual value	Present value	Equivalent annual value
Climate Benefits [b]	$55,000	$5,200	.....	.....
Net Compliance Costs	7,200	680	6,300	760
Compliance Costs	13,000	1,200	10,000	1,200
Product Recovery	5,500	520	3,900	470
Net Benefits	48,000	4,500	49,000	4,500
Non-Monetized Benefits	Climate and ozone health benefits from reducing 41 million short tons of methane from 2023 to 2035. $PM_{2.5}$ and ozone health benefits from reducing 12 million short tons of VOC from 2023 to 2035 [c]. HAP benefits from reducing 480 thousand short tons of HAP from 2023 to 2035. Visibility benefits. Reduced vegetation effects.			

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.
[b] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the social cost of methane (SC-CH_4) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from $22 billion to $150 billion ($2.4 billion to $14 billion) over 2023 to 2035 for the proposed option. Please see Table 3–5 and Table 3–7 of the RIA for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. All net benefits are calculated using climate benefits discounted at 3 percent.
[c] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix B of the RIA, which is included in the docket.

II. General Information

A. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 6—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211120	Crude Petroleum Extraction.
	211130	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal Government	.....	Not affected.
State/local/Tribal government	.....	Not affected.

[1] North American Industry Classification System (NAICS).

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in the table could also be affected by this action. To determine whether your entity is affected by this action, you should carefully examine the applicability criteria found in 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).

B. How do I obtain a copy of this document, background information, and other related information?

In addition to being available in the docket, an electronic copy of the proposed action is available on the internet. Following signature by the Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website. A redline version of the regulatory language that incorporates the proposed changes described in section X for NSPS OOOO and NSPS OOOOa is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2021–0317). The EPA plans to propose the regulatory language for NSPS OOOOb and EG OOOOc through a supplemental action.

III. Air Emissions From the Crude Oil and Natural Gas Sector and Public Health and Welfare

A. Impacts of GHGs, VOCs and SO_2 Emissions on Public Health and Welfare

As noted previously, the Oil and Natural Gas Industry emits a wide range of pollutants, including GHGs (such as methane and CO_2), VOCs, SO_2, NO_X, H_2S, CS_2, and COS. See 49 FR 2636, 2637 (January 20, 1984). As noted below, to this point, the EPA has focused its regulatory efforts on GHGs, VOC, and SO_2.[10]

1. Climate Change Impacts From GHGs Emissions

Elevated concentrations of GHGs are and have been warming the planet, leading to changes in the Earth's climate including changes in the frequency and intensity of heat waves, precipitation, and extreme weather events; rising seas; and retreating snow and ice. The changes taking place in the atmosphere as a result of the well-documented buildup of GHGs due to human activities are changing the climate at a pace and in a way that threatens human health, society, and the natural environment. Human induced GHGs, largely derived from our reliance on fossil fuels, are causing serious and life-threatening environmental and health impacts.

Extensive additional information on climate change is available in the scientific assessments and the EPA documents that are briefly described in this section, as well as in the technical and scientific information supporting them. One of those documents is the EPA's 2009 *Endangerment and Cause or Contribute Findings for GHGs Under Section 202(a)* of the CAA (74 FR 66496, December 15, 2009).[11] In the 2009 Endangerment Findings, the Administrator found under section 202(a) of the CAA that elevated atmospheric concentrations of six key well-mixed GHGs—CO_2, CH_4, N_2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—''may reasonably be anticipated to endanger the public health and welfare of current and future generations'' (74 FR 66523, December 15, 2009), and the science and observed changes have confirmed and strengthened the understanding and concerns regarding the climate risks considered in the Finding. The 2009 Endangerment Findings, together with the extensive scientific and technical evidence in the supporting record, documented that climate change caused by human emissions of GHGs threatens the public health of the U.S. population. It explained that by raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses (74 FR 66497, December 15, 2009). While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. (74 FR 66525, December 15, 2009). The 2009 Endangerment Findings further explained that compared to a future without climate change, climate change is expected to increase tropospheric ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst tropospheric ozone problems, and thereby increase the risk of adverse effects on public health (74 FR 66525, December 15, 2009). Climate change is also expected to cause more intense hurricanes and more frequent and intense storms of other types and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders (74 FR 66525, December 15, 2009). Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects (74 FR 66498, December 15, 2009).

The 2009 Endangerment Findings also documented, together with the extensive scientific and technical evidence in the supporting record, that climate change touches nearly every aspect of public welfare[12] in the U.S. with resulting economic costs, including: Changes in water supply and quality due to increased frequency of drought and extreme rainfall events; increased risk of storm surge and flooding in coastal areas and land loss due to inundation; increases in peak electricity demand and risks to electricity infrastructure; and the potential for significant agricultural disruptions and crop failures (though offset to some extent by carbon fertilization). These impacts are also global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S. (74 FR 66530, December 15, 2009).

In 2016, the Administrator similarly issued Endangerment and Cause or Contribute Findings for GHG emissions from aircraft under section 231(a)(2)(A) of the CAA (81 FR 54422, August 15, 2016).[13] In the 2016 Endangerment Findings, the Administrator found that the body of scientific evidence amassed in the record for the 2009 Endangerment Findings compellingly supported a similar endangerment finding under CAA section 231(a)(2)(A), and also found that the science assessments released between the 2009 and the 2016 Findings, ''strengthen and further support the judgment that GHGs in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future generations.'' (81 FR 54424, August 15, 2016).

Since the 2016 Endangerment Findings, the climate has continued to change, with new records being set for several climate indicators such as global average surface temperatures, GHG concentrations, and sea level rise. Moreover, heavy precipitation events

[10] We note that the EPA's focus on GHGs (in particular methane), VOC, and SO_2 in these analyses, does not in any way limit the EPA's authority to promulgate standards that would apply to other pollutants emitted from the Crude Oil and Natural Gas source category, if the EPA determines in the future that such action is appropriate.

[11] In describing these 2009 Findings in this proposal, the EPA is neither reopening nor revisiting them.

[12] The CAA states in section 302(h) that ''[a]ll language referring to effects on welfare includes, but is not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other air pollutants.'' 42 U.S.C. 7602(h).

[13] In describing these 2016 Findings in this proposal, the EPA is neither reopening nor revisiting them.

have increased in the eastern U.S. while agricultural and ecological drought has increased in the western U.S. along with more intense and larger wildfires.[14] These and other trends are examples of the risks discussed the 2009 and 2016 Endangerment Findings that have already been experienced. Additionally, major scientific assessments continue to demonstrate advances in our understanding of the climate system and the impacts that GHGs have on public health and welfare both for current and future generations. These updated observations and projections document the rapid rate of current and future climate change both globally and in the U.S. These assessments include:

- U.S. Global Change Research Program's (USGCRP) 2016 Climate and Health Assessment [15] and 2017–2018 Fourth National Climate Assessment (NCA4). [16] [17]
- IPCC's 2018 Global Warming of 1.5 °C,[18] 2019 Climate Change and Land,[19] and the 2019 Ocean and Cryosphere in a Changing Climate [20] assessments, as well as the 2021 IPCC Sixth Assessment Report (AR6).[21]
- The NAS 2016 Attribution of Extreme Weather Events in the Context of Climate Change,[22] 2017 Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide,[23] and 2019 Climate Change and Ecosystems [24] assessments.
- National Oceanic and Atmospheric Administration's (NOAA) annual State of the Climate reports published by the Bulletin of the American Meteorological Society,[25] most recently in August of 2020.
- EPA Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts (2021).[26]

The most recent information demonstrates that the climate is continuing to change in response to the human-induced buildup of GHGs in the atmosphere. These recent assessments show that atmospheric concentrations of GHGs have risen to a level that has no precedent in human history and that they continue to climb, primarily as a result of both historic and current anthropogenic emissions, and that these elevated concentrations endanger our health by affecting our food and water sources, the air we breathe, the weather we experience, and our interactions with the natural and built environments. For example, atmospheric concentrations of one of these GHGs, CO_2, measured at Mauna Loa in Hawaii and at other sites around the world reached 414 ppm in 2020 (nearly 50 percent higher than pre-industrial levels),[27] and has continued to rise at a rapid rate. Global average temperature has increased by about 1.1 degrees Celsius (°C) (2.0 degrees Fahrenheit (°F)) in the 2011–2020 decade relative to 1850–1900.[28] The years 2014–2020 were the warmest seven years in the 1880–2020 record, contributing to the warmest decade on record with a decadal temperature of 0.82 °C (1.48 °F) above the 20th century.[29] [30] The IPCC determined (with medium confidence) that this past decade was warmer than any multi-century period in at least the past 100,000 years.[31] Global average sea level has risen by about 8 inches (about 21 centimeters (cm)) from 1901 to 2018, with the rate from 2006 to 2018 (0.15 inches/year or 3.7 millimeters (mm)/year) almost twice the rate over the 1971 to 2006 period, and three times the rate of the 1901 to 2018 period.[32] The rate of sea level rise over the 20th century was higher than in any other century in at least the last 2,800 years.[33] Higher CO_2 concentrations have led to acidification of the surface ocean in recent decades to an extent unusual in the past 2 million years, with negative impacts on marine organisms that use calcium carbonate to build shells or skeletons.[34] Arctic sea ice extent continues to decline in all months of the year; the most rapid reductions occur in September (very likely almost a 13 percent decrease per decade between 1979 and 2018) and are unprecedented in at least 1,000 years.[35] Human-induced climate change has led to heatwaves and heavy precipitation becoming more frequent and more intense, along with increases in

[14] See later in this section for specific examples. An additional resource for indicators can be found at *https://www.epa.gov/climate-indicators.*

[15] USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp.

[16] USGCRP, 2017: *Climate Science Special Report: Fourth National Climate Assessment,* Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp, doi: 10.7930/J0J964J6.

[17] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[18] IPCC, 2018: *Global Warming of 1.5 °C.* An IPCC Special Report on the impacts of global warming of 1.5 °C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)].

[19] IPCC, 2019: *Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems* [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.-O. Pörtner, D.C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, (eds.)].

[20] IPCC, 2019: *IPCC Special Report on the Ocean and Cryosphere in a Changing Climate* [H.-O. Pörtner, D.C. Roberts, V. Masson-Delmotte, P. Zhai, M. Tignor, E. Poloczanska, K. Mintenbeck, A. Alegría, M. Nicolai, A. Okem, J. Petzold, B. Rama, N.M. Weyer (eds.)].

[21] IPCC, 2021: *Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu and B. Zhou (eds.)]. Cambridge University Press. In Press.

[22] National Academies of Sciences, Engineering, and Medicine. 2016. *Attribution of Extreme Weather Events in the Context of Climate Change.* Washington, DC: The National Academies Press. *https://dio.org/10.17226/21852.*

[23] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/24651.*

[24] National Academies of Sciences, Engineering, and Medicine. 2019. *Climate Change and Ecosystems.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/25504.*

[25] Blunden, J., and D.S. Arndt, Eds., 2020: State of the Climate in 2019. Bull. Amer. Meteor. Soc, S1–S429, *https://doi.org/10.1175/2020BAMSStateofthe Climate.1.*

[26] EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430–R–21–003.

[27] *https://climate.nasa.gov/vital-signs/carbon-dioxide/.*

[28] IPCC, 2021.

[29] NOAA National Centers for Environmental Information, State of the Climate: Global Climate Report for Annual 2020, published online January 2021, retrieved on February 10, 2021 from *https://www.ncdc.noaa.gov/sotc/global/202013.*

[30] Blunden, J., and D.S. Arndt, Eds., 2020: State of the Climate in 2019. Bull. Amer. Meteor. Soc, S1–S429, *https://doi.org/10.1175/2020BAMSStateofthe Climate.1.*

[31] IPCC, 2021.

[32] IPCC, 2021.

[33] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[34] IPCC, 2021.

[35] IPCC, 2021.

agricultural and ecological droughts [36] in many regions.[37]

The assessment literature demonstrates that modest additional amounts of warming may lead to a climate different from anything humans have ever experienced. The present-day CO_2 concentration of 414 ppm is already higher than at any time in the last 2 million years.[38] If concentrations exceed 450 ppm, they would likely be higher than any time in the past 23 million years:[39] at the current rate of increase of more than 2 ppm a year, this would occur in about 15 years. While GHGs are not the only factor that controls climate, it is illustrative that 3 million years ago (the last time CO_2 concentrations were this high) Greenland was not yet completely covered by ice and still supported forests, while 23 million years ago (the last time concentrations were above 450 ppm) the West Antarctic ice sheet was not yet developed, indicating the possibility that high GHGs concentrations could lead to a world that looks very different from today and from the conditions in which human civilization has developed. If the Greenland and Antarctic ice sheets were to melt substantially, sea levels would rise dramatically—the IPCC estimated that over the next 2,000 years, sea level will rise by 7 to 10 feet even if warming is limited to 1.5 °C (2.7 °F), from 7 to 20 feet if limited to 2 °C (3.6 °F), and by 60 to 70 feet if warming is allowed to reach 5 °C (9 °F) above preindustrial levels.[40] For context, almost all of the city of Miami is less than 25 feet above sea level, and the NCA4 stated that 13 million Americans would be at risk of migration due to 6 feet of sea level rise. Moreover, the CO_2 being absorbed by the ocean has resulted in changes in ocean chemistry due to acidification of a magnitude not seen in 65 million years,[41] putting many marine species—particularly calcifying species—at risk.

The NCA4 found that it is very likely (greater than 90 percent likelihood) that by mid-century, the Arctic Ocean will be almost entirely free of sea ice by late summer for the first time in about 2 million years.[42] Coral reefs will be at risk for almost complete (99 percent) losses with 1 °C (1.8 °F) of additional warming from today (2 °C or 3.6 °F since preindustrial). At this temperature, between 8 and 18 percent of animal, plant, and insect species could lose over half of the geographic area with suitable climate for their survival, and 7 to 10 percent of rangeland livestock would be projected to be lost.[43]

Every additional increment of temperature comes with consequences. For example, the half degree of warming from 1.5 to 2 °C (0.9 °F of warming from 2.7 °F to 3.6 °F) above preindustrial temperatures is projected on a global scale to expose 420 million more people to frequent extreme heatwaves, and 62 million more people to frequent exceptional heatwaves (where heatwaves are defined based on a heat wave magnitude index which takes into account duration and intensity—using this index, the 2003 French heat wave that led to almost 15,000 deaths would be classified as an ''extreme heatwave'' and the 2010 Russian heatwave which led to thousands of deaths and extensive wildfires would be classified as ''exceptional''). It would increase the frequency of sea-ice-free Arctic summers from once in a hundred years to once in a decade. It could lead to 4 inches of additional sea level rise by the end of the century, exposing an additional 10 million people to risks of inundation, as well as increasing the probability of triggering instabilities in either the Greenland or Antarctic ice sheets. Between half a million and a million additional square miles of permafrost would thaw over several centuries. Risks to food security would increase from medium to high for several lower income regions in the Sahel, southern Africa, the Mediterranean, central Europe, and the Amazon. In addition to food security issues, this temperature increase would have implications for human health in terms of increasing ozone concentrations, heatwaves, and vector-borne diseases (for example, expanding the range of the mosquitoes which carry dengue fever, chikungunya, yellow fever, and the Zika virus, or the ticks which carry Lyme. babesiosis, or Rocky Mountain Spotted Fever).[44] Moreover, every additional increment in warming leads to larger changes in extremes, including the potential for events unprecedented in the observational record. Every additional degree will intensify extreme precipitation events by about 7 percent. The peak winds of the most intense tropical cyclones (hurricanes) are projected to increase with warming. In addition to a higher intensity, the IPCC found that precipitation and frequency of rapid intensification of these storms has already increased, while the movement speed has decreased, and elevated sea levels have increased coastal flooding, all of which make these tropical cyclones more damaging.[45]

The NCA4 also evaluated a number of impacts specific to the U.S. Severe drought and outbreaks of insects like the mountain pine beetle have killed hundreds of millions of trees in the western U.S. Wildfires have burned more than 3.7 million acres in 14 of the 17 years between 2000 and 2016, and Federal wildfire suppression costs were about a billion dollars annually.[46] The National Interagency Fire Center has documented U.S. wildfires since 1983, and the ten years with the largest acreage burned have all occurred since 2004.[47] Wildfire smoke degrades air quality increasing health risks, and more frequent and severe wildfires due to climate change would further diminish air quality, increase incidences of respiratory illness, impair visibility, and disrupt outdoor activities, sometimes thousands of miles from the location of the fire. Meanwhile, sea level rise has amplified coastal flooding and erosion impacts, requiring the installation of costly pump stations, flooding streets, and increasing storm surge damages. Tens of billions of dollars of U.S. real estate could be below sea level by 2050 under some scenarios. Increased frequency and duration of drought will reduce agricultural productivity in some regions, accelerate depletion of water supplies for irrigation, and expand the distribution and incidence of pests and diseases for crops and livestock. The NCA4 also recognized that climate change can increase risks to national security, both through direct impacts on military infrastructure, but also by affecting factors such as food and water availability that can exacerbate conflict outside U.S. borders. Droughts, floods, storm surges, wildfires, and other extreme events stress nations and people through loss of life, displacement of populations, and impacts on livelihoods.[48]

Some GHGs also have impacts beyond those mediated through climate change. For example, elevated concentrations of carbon dioxide stimulate plant growth (which can be positive in the case of beneficial species, but negative in terms of weeds and invasive species, and can also lead to a reduction in plant

[36] These are drought measures based on soil moisture.

[37] IPCC, 2021.

[38] IPCC, 2021.

[39] IPCC, 2013.

[40] IPCC, 2021.

[41] IPCC, 2018.

[42] USGCRP, 2018.

[43] IPCC, 2018.

[44] IPCC, 2018.

[45] IPCC, 2021.

[46] USGCRP, 2018

[47] NIFC (National Interagency Fire Center). 2021. Total wildland fires and acres (1983–2020). Accessed August 2021. *www.nifc.gov/fireInfo/fireInfo_stats_totalFires.html.*

[48] USGCRP, 2018.

micronutrients)[49] and cause ocean acidification. Nitrous oxide depletes the levels of protective stratospheric ozone.[50]

As methane is the primary GHG addressed in this proposal, it is relevant to highlight some specific trends and impacts specific to methane. Concentrations of methane reached 1879 parts per billion (ppb) in 2020, more than two and a half times the preindustrial concentration of 722 ppb.[51] Moreover, the 2020 concentration was an increase of almost 13 ppb over 2019—the largest annual increase in methane concentrations of the period since the early 1990s, continuing a trend of rapid rise since a temporary pause ended in 2007.[52] Methane has a high radiative efficiency—almost 30 times that of carbon dioxide per ppb (and therefore, 80 times as much per unit mass).[53] In addition, methane contributes to climate change through chemical reactions in the atmosphere that produce tropospheric ozone and stratospheric water vapor. Human emissions of methane are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide.[54] Because of the substantial emissions of methane, and its radiative efficiency, methane mitigation is one of the best opportunities for reducing near term warming.

The tropospheric ozone produced by the reaction of methane in the atmosphere has harmful effects for human health and plant growth in addition to its climate effects.[55] In remote areas, methane is an important precursor to tropospheric ozone formation.[56] Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane.[57] Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future.[58] 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 long atmospheric lifetime when compared to these other ozone precursors.[59] Reducing methane emissions, therefore, will contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects.[60] The benefits of such reductions are global and occur in both urban and rural areas.

These scientific assessments and documented observed changes in the climate of the planet and of the U.S. present clear support regarding the current and future dangers of climate change and the importance of GHG mitigation.

2. VOC

Many VOC can be classified as HAP (*e.g.,* benzene),[61] 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 the ozone precursors VOC and NO_X. Recent observational and modeling studies have found that VOC emissions from oil and natural gas operations can impact ozone levels.[62] [63] [64] [65] 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 U.S., 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.[66]

In the EPA's 2020 Integrated Science Assessment (ISA) for Ozone and Related Photochemical Oxidants,[67] the EPA estimates the incidence of air pollution effects for those health endpoints above where the ISA classified as either causal or likely-to-be-causal. In brief, the ISA for ozone found short-term (less than one month) exposures to ozone to be

[49] Ziska, L., A. Crimmins, A. Auclair, S. DeGrasse, J.F. Garofalo, A.S. Khan, I. Loladze, A.A. Pérez de León, A.Showler, J. Thurston, and I. Walls, 2016: Ch. 7: *Food Safety, Nutrition, and Distribution. The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* U.S. Global Change Research Program, Washington, DC, 189–216. *http://dx.doi.org/10.7930/J0ZP4417*

[50] WMO (World Meteorological Organization), *Scientific Assessment of Ozone Depletion: 2018, Global Ozone Research and Monitoring Project*—Report No. 58, 588 pp., Geneva, Switzerland, 2018.

[51] Blunden et al., 2020.

[52] NOAA, *https://gml.noaa.gov/webdata/ccgg/trends/ch4/ch4_annmean_gl.txt,* accessed August 19th, 2021.

[53] IPCC, 2021.

[54] IPCC, 2021.

[55] Nolte, C.G., P.D. Dolwick, N. Fann, L.W. Horowitz, V. Naik, R.W. Pinder, T.L. Spero, D.A. Winner, and L.H. Ziska, 2018: *Air Quality. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment,* Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 512–538. doi: 10.7930/NCA4. 2018. CH13

[56] 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/.*

[57] 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.

[58] *Ibid.*

[59] *Ibid.*

[60] USGCRP, 2018.

[61] Benzene Integrated Risk Information System (IRIS) Assessment: *https://cfpub.epa.gov/ncea/iris2/chemicalLanding.cfm?substance_nmbr=276.*

[62] Benedict, K. B., Zhou, Y., Sive, B. C., Prenni, A. J., Gebhart, K. A., Fischer, E. V., . . . & Collett Jr, J. L. 2019. Volatile organic compounds and ozone in Rocky Mountain National Park during FRAPPE. *Atmospheric Chemistry and Physics, 19*(1), 499–521.

[63] Lindaas, J., Farmer, D. K., Pollack, I. B., Abeleira, A., Flocke, F., & Fischer, E. V. 2019. Acyl peroxy nitrates link oil and natural gas emissions to high ozone abundances in the Colorado Front Range during summer 2015. *Journal of Geophysical Research: Atmospheres, 124*(4), 2336–2350.

[64] McDuffie, E. E., Edwards, P. M., Gilman, J. B., Lerner, B. M., Dubé, W. P., Trainer, M., . . . & Brown, S. S. 2016. Influence of oil and gas emissions on summertime ozone in the Colorado Northern Front Range. *Journal of Geophysical Research: Atmospheres, 121*(14), 8712–8729.

[65] Tzompa-Sosa, Z. A., & Fischer, E. V. 2021. Impacts of emissions of C2-C5 alkanes from the US oil and gas sector on ozone and other secondary species. *Journal of Geophysical Research: Atmospheres, 126*(1), e2019JD031935.

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

[67] Integrated Science Assessment (ISA) for Ozone and Related Photochemical Oxidants (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–20/012, 2020.

causally related to respiratory effects, a ''likely to be causal'' relationship with metabolic effects and a ''suggestive of, but not sufficient to infer, a causal relationship'' for central nervous system effects, cardiovascular effects, and total mortality. The ISA reported that long-term exposures (one month or longer) to ozone are ''likely to be causal'' for respiratory effects including respiratory mortality, and a ''suggestive of, but not sufficient to infer, a causal relationship'' for cardiovascular effects, reproductive effects, central nervous system effects, metabolic effects, and total mortality. An example of quantified incidence of ozone health effects can be found in the Regulatory Impact Analysis for the Final Revised Cross-State Air Pollution Rule (CSAPR) Update.

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.[68]

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

B. Oil and Natural Gas Industry and Its Emissions

This section generally describes the structure of the Oil and Natural Gas Industry, the interconnected production, processing, transmission and storage, and distribution segments that move product from well to market, and types of emissions sources in each segment and the industry's emissions.

1. Oil and Natural Gas Industry—Structure

The EPA characterizes the oil and natural gas industry's operations as being generally composed of four segments: (1) Extraction and production of crude oil and natural gas (''oil and natural gas production''), (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution.[69] [70] The EPA regulates oil refineries as a separate source category; accordingly, as with the previous oil and gas NSPS rulemakings, for purposes of this proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate.'' [71]

a. Production Segment

The oil and natural gas production segment includes the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treatment of oil and/or natural gas (including condensate). Although many wells produce a combination of oil and natural gas, wells can generally be grouped into two categories, oil wells and natural gas wells. Oil wells comprise two types, oil wells that produce crude oil only and oil wells that produce both crude oil and natural gas (commonly referred to as ''associated'' gas). Production equipment and components located on the well pad may include, but are not limited to, wells and related casing heads; tubing heads; ''Christmas tree'' piping, pumps, compressors; heater treaters; separators; storage vessels; pneumatic devices; and dehydrators. Production operations include well drilling, completion, and recompletion processes, including all the portable non-self-propelled apparatuses associated with those operations.

Other sites that are part of the production segment include ''centralized tank batteries,'' stand-alone sites where oil, condensate, produced water, and natural gas from several wells may be separated, stored, or treated. The production segment also includes gathering pipelines, gathering and boosting compressor stations, and related components that collect and transport the oil, natural gas, and other materials and wastes from the wells to the refineries or natural gas processing plants.

Of these products, crude oil and natural gas undergo successive, separate processing. Crude oil is separated from water and other impurities and transported to a refinery via truck, railcar, or pipeline. As noted above, the EPA treats oil refineries as a separate source category, accordingly, for present purposes, the oil component of the production segment ends at the point of custody transfer at the refinery.[72]

The separated, unprocessed natural gas is commonly referred to as field gas and is composed of methane, natural gas liquids (NGL), and other impurities, such as water vapor, H_2S, CO_2, helium, and nitrogen. Ethane, propane, butane, isobutane, and pentane are all considered NGL and often are sold separately for a variety of different uses. Natural gas with high methane content is referred to as ''dry gas,'' while natural gas with significant amounts of ethane, propane, or butane is referred to as ''wet gas.'' Natural gas typically is sent to gas processing plants in order to separate NGLs for use as feedstock for petrochemical plants, burned for space heating and cooking, or blended into vehicle fuel.

b. Processing Segment

The natural gas processing segment consists of separating certain hydrocarbons (HC) and fluids from the natural gas to produce ''pipeline quality'' dry natural gas. The degree and

[69] The EPA previously described an overview of the sector in section 2.0 of the 2011 Background Technical Support Document to 40 CFR part 60, subpart OOOO, located at Docket ID Item No. EPA–HQ–OAR–2010–0505–0045, and section 2.0 of the 2016 Background Technical Support Document to 40 CFR part 60, subpart OOOOa, located at Docket ID Item No. EPA–HQ–OAR–2010–0505–7631.

[70] While generally oil and natural gas production includes both onshore and offshore operations, 40 CFR part 60, subpart OOOOa addresses onshore operations.

[71] For regulatory purposes, the EPA defines the Crude Oil and Natural Gas source category to mean (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station. The distribution segment is not part of the defined source category.

[72] See 40 CFR part 60, subparts J and Ja, and 40 CFR part 63, subparts CC and UUU.

location of processing is dependent on factors such as the type of natural gas (*e.g.,* wet or dry gas), market conditions, and company contract specifications. Typically, processing of natural gas begins in the field and continues as the gas is moved from the field through gathering and boosting compressor stations to natural gas processing plants, where the complete processing of natural gas takes place. Natural gas processing operations separate and recover NGL or other non-methane gases and liquids from field gas through one or more of the following processes: oil and condensate separation, water removal, separation of NGL, sulfur and CO_2 removal, fractionation of NGL, and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

c. Transmission and Storage Segment

Once natural gas processing is complete, the resulting natural gas exits the natural gas process plant and enters the transmission and storage segment where it is transmitted to storage and/or distribution to the end user.

Pipelines in the natural gas transmission and storage segment can be interstate pipelines, which carry natural gas across state boundaries, or intrastate pipelines, which transport the gas within a single state. Basic components of the two types of pipelines are the same, though interstate pipelines may be of a larger diameter and operated at a higher pressure. To ensure that the natural gas continues to flow through the pipeline, the natural gas must periodically be compressed, thereby increasing its pressure. Compressor stations perform this function and are usually placed at 40- to 100-mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

Another part of the transmission and storage segment are aboveground and underground natural gas storage facilities. Storage facilities hold natural gas for use during peak seasons. The main difference between underground and aboveground storage sites is that storage takes place in storage vessels constructed of non-earthen materials in aboveground storage. Underground storage of natural gas typically occurs in depleted natural gas or oil reservoirs and salt dome caverns. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, typically other processes occur, including compression, dehydration, and flow measurement.

d. Distribution Segment

The distribution segment provides the final step in delivering natural gas to customers.[73] The natural gas enters the distribution segment from delivery points located along interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission and storage segment and enters the distribution segment is a local distribution company's custody transfer station, commonly referred to as the ''city-gate.'' Natural gas distribution systems consist of over 2 million miles of piping, including mains and service pipelines to the customers. If the distribution network is large, compressor stations may be necessary to maintain flow; however, these stations are typically smaller than transmission compressor stations. Distribution systems include metering stations and regulating stations, which allow distribution companies to monitor the natural gas as it flows through the system.

2. Oil and Natural Gas Industry—Emissions

The oil and natural gas industry sector is the largest source of industrial methane emissions in the U.S.[74] Natural gas is comprised primarily of methane; every natural gas leak or intentional release through venting or other industrial processes constitutes a release of methane. Methane is a potent greenhouse gas; over a 100-year timeframe, it is nearly 30 times more powerful at trapping climate warming heat than CO_2, and over a 20-year timeframe, it is 83 times more powerful.[75] Because methane is a powerful greenhouse gas and is emitted in large quantities, reductions in methane emissions provide a significant benefit in reducing near-term warming. Indeed, one third of the warming due to GHGs that we are experiencing today is due to human emissions of methane. Additionally, the Crude Oil and Natural Gas sector emits, in varying concentrations and amounts, a wide range of other health-harming pollutants, including VOCs, SO_2, NO_X, H_2S, CS_2, and COS. The year 2016 modeling platform produced by U.S. EPA estimated about 3 million tons of VOC are emitted by oil and gas-related sources.[76]

Emissions of methane and these co-pollutants occur in every segment of the Crude Oil and Natural Gas source category. Many of the processes and equipment types that contribute to these emissions are found in every segment of the source category and are highly similar across segments. Emissions from the crude oil portion of the regulated source category result primarily from field production operations, such as venting of associated gas from oil wells, oil storage vessels, and production-related equipment such as gas dehydrators, pig traps, and pneumatic devices. Emissions from the natural gas portion of the industry can occur in all segments. As natural gas moves through the system, emissions primarily result from intentional venting through normal operations, routine maintenance, unintentional fugitive emissions, flaring, malfunctions, and system upsets. Venting can occur through equipment design or operational practices, such as the continuous and intermittent bleed of gas from pneumatic controllers (devices that control gas flows, levels, temperatures, and pressures in the equipment). In addition to vented emissions, emissions can occur from leaking equipment (also referred to as fugitive emissions) in all parts of the infrastructure, including major production and processing equipment (*e.g.,* separators or storage vessels) and individual components (*e.g.,* valves or connectors). Flares are commonly used throughout each segment in the Oil and Natural Gas Industry as a control device to provide pressure relief to prevent risk of explosions and to destroy methane, which has a high global warming potential, and convert it to CO_2 which has a lower global warming potential, and to also control other air pollutants such as VOC.

''Super-emitting'' events, sites, or equipment, where a small proportion of sources account for a large proportion of overall emissions, can occur throughout the Oil and Natural Gas Industry and have been observed to occur in the equipment types and activities covered by this proposed action. There are a number of definitions for the term ''super-emitter.'' A 2018 National Academies of Sciences, Engineering, and Medicine report [77] on methane discussed three categories of ''high-emitting'' sources:

[73] The distribution segment is not included in the definition of the Crude Oil and Natural Gas source category that is currently regulated under 40 CFR part 60, subpart OOOOa.

[74] H.R. Rep. No. 117–64, 4 (2021) (Report by the House Committee on Energy and Commerce concerning H.J. Res. 34, to disapprove the 2020 Policy Rule) (House Report).

[75] IPCC, 2021.

[76] *https://www.epa.gov/sites/default/files/2020-11/documents/2016v1_emismod_tsd_508.pdf.*

[77] *https://www.nap.edu/download/24987#.*

• Routine or ''chronic'' high-emitting sources, which regularly emit at higher rates relative to ''peers'' in a sample. Examples include large facilities, or large emissions at smaller facilities caused by poor design or operational practices.

• Episodic high-emitting sources, which are typically large in nature and are generally intentional releases from known maintenance events at a facility. Examples include gas well liquids unloading, well workovers and maintenance activities, and compressor station or pipeline blowdowns.

• Malfunctioning high-emitting sources, which can be either intermittent or prolonged in nature and result from malfunctions and poor work practices. Examples include malfunctioning intermittent pneumatic controllers and stuck open dump valves. Another example is well blowout events. For example, a 2018 well blowout in Ohio was estimated to have emitted over 60,000 tons of methane.[78]

Super-emitters have been observed at many different scales, from site-level to component-level, across many research studies.[79] Studies will often develop a study-specific definition such as a top percentile of emissions in a study population (*e.g.,* top 10 percent), emissions exceeding a certain threshold (*e.g.,* 26 kg/day), emissions over a certain detection threshold (*e.g.,* 1–3 g/s) or as facilities with the highest proportional emission rate.[80] For certain equipment types and activities, the EPA's GHG emission estimates include the full range of conditions, including ''super-emitters.'' For other situations, where data are available, emissions estimates for abnormal events are calculated separately and included in the Inventory of U.S. Greenhouse Gas Emissions and Sinks (''GHGI'') (*e.g.,* Aliso Canyon leak event).[81] Given the variability of practices and technologies across oil and gas systems and the occurrence of episodic events, it is possible that the EPA's estimates do not include all methane emissions from abnormal events. The EPA continues to work through its stakeholder process to review new data from the EPA's Greenhouse Gas Reporting Program (''GHGRP'') petroleum and natural gas systems source category (40 CFR part 98, subpart W, also referred to as ''GHGRP subpart W'') and research studies to assess how emissions estimates can be improved. Because lost gas, whether through fugitive emissions, unintentional gas carry through, or intentional releases, represents lost earning potential, the industry benefits from capturing and selling emissions of natural gas (and methane). Limiting super-emitters through actions included in this rule such as reducing fugitive emissions, using lower emitting equipment where feasible, and employing best management practices will not only reduce emissions but reduce the loss of revenue from this valuable commodity.

Below we provide estimated emissions of methane, VOC, and SO_2 from Oil and Natural Gas Industry operation sources.

Methane emissions in the U.S. and from the Oil and Natural Gas industry. Official U.S. estimates of national level GHG emissions and sinks are developed by the EPA for the GHGI in fulfillment of commitments under the United Nations Framework Convention on Climate Change. The GHGI, which includes recent trends, is organized by industrial sector. The oil and natural gas production, natural gas processing, and natural gas transmission and storage sectors emit 28 percent of U.S. anthropogenic methane. Table 7 below presents total U.S. anthropogenic methane emissions for the years 1990, 2010, and 2019.

In accordance with the practice of the EPA GHGI, the EPA GHGRP, and international reporting standards under the UN Framework Convention on Climate Change, the 2007 IPCC Fourth Assessment Report value of the methane 100-year GWP is used for weighting emissions in the following tables. The 100-year GWP value of 25 for methane indicates that one ton of methane has approximately as much climate impact over a 100-year period as 25 tons of carbon dioxide. The most recent IPCC AR6 assessment has estimated a slightly larger 100-year GWP of methane of almost 30 (specifically, either 27.2 or 29.8 depending on whether the value includes the carbon dioxide produced by the oxidation of methane in the atmosphere). As mentioned earlier, because methane has a shorter lifetime than carbon dioxide, the emissions of a ton of methane will have more impact earlier in the 100-year timespan and less impact later in the 100-year timespan relative to the emissions of a 100-year GWP-equivalent quantity of carbon dioxide: When using the AR6 20-year GWP of 81, which only looks at impacts over the next 20 years, the total US emissions of methane in 2019 would be equivalent to about 2140 MMT CO_2.

TABLE 7—U.S. METHANE EMISSIONS BY SECTOR

[Million metric tons carbon dioxide equivalent (MMT CO_2 EQ.)]

Sector	1990	2010	2019
Oil and Natural Gas Production, and Natural Gas Processing and Transmission and Storage	189	176	182
Landfills	177	124	114
Enteric Fermentation	165	172	179

[78] Pandey et al. (2019). Satellite observations reveal extreme methane leakage from a natural gas well blowout. PNAS December 26, 2019 116 (52) 26376–26381.

[79] See for example, Brandt, A., Heath, G., Cooley, D. (2016) *Methane leaks from natural gas systems follow extreme distributions.* Environ. Sci. Technol., DOI: 10.1021/acs.est.6b04303; 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; Mitchell, A., et al. (2015), *Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results.* Environmental Science & Technology, 49(5), 3219–3227; Allen, D., et al. (2014), *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers.* Environmental Science & Technology.

[80] Caulton et al. (2019). *Importance of Super-emitter Natural Gas Well Pads in the Marcellus Shale.* Environ. Sci. Technol. 2019, 53, 4747–4754; Zavala-Araiza, D., Alvarez, R., Lyon, D, et al. (2016). *Super-emitters in natural gas infrastructure are caused by abnormal process conditions.* Nat Commun 8, 14012 (2017). *https://www.nature.com/articles/ncomms14012;* Lyon, et al. (2016). *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites.* Environ. Sci. Technol. 2016, 50, 4877–4886. *https://pubs.acs.org/doi/10.1021/acs.est.6b00705;* and Zavala-Araiza D, et al. (2015). *Toward a functional definition of methane superemitters: Application to natural gas production sites.* 49 ENVTL. SCI. & TECH. 8167, 8168 (2015). *https://pubs.acs.org/doi/10.1021/acs.est.5b00133.*

[81] The EPA's emission estimates in the GHGI are developed with the best data available at the time of their development, including data from the Greenhouse Gas Reporting Program (GHGRP) in 40 CFR part 98, subpart W, and from recent research studies. GHGRP subpart W emissions data used in the GHGI are quantified by reporters using direct measurements, engineering calculations, or emission factors, as specified by the regulation. The EPA has a multi-step data verification process for GHGRP subpart W data, including automatic checks during data-entry, statistical analyses on completed reports, and staff review of the reported data. Based on the results of the verification process, the EPA follows up with facilities to resolve mistakes that may have occurred.

TABLE 7—U.S. METHANE EMISSIONS BY SECTOR—Continued

[Million metric tons carbon dioxide equivalent (MMT CO_2 EQ.)]

Sector	1990	2010	2019
Coal Mining	96	82	47
Manure Management	37	55	62
Other Oil and Gas Sources	46	17	15
Wastewater Treatment	20	19	18
Other Methane Sources [82]	46	47	42
Total Methane Emissions	777	692	660

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2019 (published April 14, 2021), calculated using GWP of 25. **Note:** Totals may not sum due to rounding.

Table 8 below presents total methane emissions from natural gas production through transmission and storage and petroleum production, for years 1990, 2010, and 2019, in MMT CO_2 Eq. (or million metric tons CO_2 Eq.) of methane.

TABLE 8—U.S. METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[MMT CO_2 EQ.]

Sector	1990	2010	2019
Natural Gas Production	63	97	94
Natural Gas Processing	21	10	12
Natural Gas Transmission and Storage	57	30	37
Petroleum Production	48	39	38

Emissions from the Inventory of United States Greenhouse Gas Emissions and Sinks: 1990–2019 (published April 14, 2021), calculated using GWP of 25. **Note:** Totals may not sum due to rounding.

Global GHG Emissions. For additional background information and context, we used 2018 World Resources Institute Climate Watch data to make comparisons between U.S. oil and natural gas production and natural gas processing and transmission and storage emissions and the emissions inventories of entire countries and regions.[83] The U.S. methane emissions from oil and natural gas production and natural gas processing and transmission and storage constitute 0.4 percent of total global emissions of all GHGs (48,601 MMT CO2 Eq.) from all sources.[84] Ranking U.S. emissions of methane from oil and natural gas production and natural gas processing and transmission and storage against total GHG emissions for entire countries (using 2018 Climate Watch data), shows that these emissions are comparatively large as they exceed the national-level emissions totals for all GHGs and all anthropogenic sources for Colombia, the Czech Republic, Chile, Belgium, and over 160 other countries. What that means is that the U.S. emits more of a single GHG—methane—from a single sector—the oil and gas sector—than the total combined GHGs emitted by 164 out of 194 total countries. Furthermore, U.S. emissions of methane from oil and natural gas production and natural gas processing and transmission and storage are greater than the sum of total emissions of 64 of the lowest-emitting countries and territories, using the 2018 Climate Watch data set.

As illustrated by the domestic and global GHGs comparison data summarized above, the collective GHG emissions from the Crude Oil and Natural Gas source category are significant, whether the comparison is domestic (where this sector is the largest source of methane emissions, accounting for 28 percent of U.S. methane and 3 percent of total U.S. emissions of all GHGs), global (where this sector, accounting for 0.4 percent of all global GHG emissions, emits more than the total national emissions of over 160 countries, and combined emissions of over 60 countries), or when both the domestic and global GHG emissions comparisons are viewed in combination. Consideration of the global context is important. GHG emissions from U.S. Oil and Natural Gas production and natural gas processing and transmission and storage will become globally well-mixed in the atmosphere, and thus will have an effect on the U.S. regional climate, as well as the global climate as a whole for years and indeed many decades to come. No single GHG source category dominates on the global scale. While the Crude Oil and Natural Gas source category, like many (if not all) individual GHG source categories, could appear small in comparison to total emissions, in fact, it is a very important contributor in terms of both absolute emissions, and in comparison to other source categories globally or within the U.S.

The IPCC AR6 assessment determined that ''From a physical science perspective, limiting human-induced global warming to a specific level requires limiting cumulative CO_2 emissions, reaching at least net zero CO_2 emissions, along with strong reductions in other GHG emissions.'' The report also singled out the importance of ''strong and sustained CH_4 emission reductions'' in part due to the short lifetime of methane leading to the near-term cooling from reductions in methane emissions, which can offset the warming that will result due to reductions in emissions of cooling aerosols such as SO_2. Therefore, reducing methane emissions globally is an important facet in any strategy to limit warming. In the oil and gas sector,

[82] Other sources include rice cultivation, forest land, stationary combustion, abandoned oil and natural gas wells, abandoned coal mines, mobile combustion, composting, and several sources emitting less than 1 MMT CO_2 Eq. in 2019.

[83] The Climate Watch figures presented here come from the PIK PRIMAP-hist dataset included on Climate Watch. The PIK PRIMAP-hist dataset combines the United Nations Framework Convention on Climate Change (UNFCCC) reported data where available and fills gaps with other sources. It does not include land use change and forestry but covers all other sectors. *https://www.climatewatchdata.org/ghg-emissions?end_year=2018&source=PIK&start_year=1990.*

methane reductions are highly achievable and cost-effective using existing and well-known solutions and technologies that actually result in recovery of saleable product.

VOC and SO_2 emissions in the U.S. and from the oil and natural gas industry. Official U.S. estimates of national level VOC and SO_2 emissions are developed by the EPA for the National Emissions Inventory (NEI), for which States are required to submit information under 40 CFR part 51, subpart A. Data in the NEI may be organized by various data points, including sector, NAICS code, and Source Classification Code. Tables 9 and 10 below present total U.S. VOC and SO_2 emissions by sector, respectively, for the year 2017, in kilotons (kt) (or thousand metric tons). The oil and natural gas sector represents the top anthropogenic U.S. sector for VOC emissions after removing the biogenics and wildfire sectors in Table 9 (about 20% of the total VOC emitting by anthropogenic sources). About 2.5 percent of the total U.S. anthropogenic SO_2 comes from the oil and natural gas sector.

TABLE 9—U.S. VOC EMISSIONS BY SECTOR

[kt]

Sector	2017
Biogenics—Vegetation and Soil	25,823
Fires—Wildfires	4,578
Oil and Natural Gas Production, and Natural Gas Processing and Transmission	2,504
Fires—Prescribed Fires	2,042
Solvent—Consumer and Commercial Solvent Use	1,610
Mobile—On-Road non-Diesel Light Duty Vehicles	1,507
Mobile—Non-Road Equipment—Gasoline	1,009
Other VOC Sources [85]	4,045
Total VOC Emissions	43,118

Emissions from the 2017 NEI (released April 2020). **Note:** Totals may not sum due to rounding.

TABLE 10—U.S. SO_2 EMISSIONS BY SECTOR

[kt]

Sector	2017
Fuel Combustion—Electric Generation—Coal	1,319
Fuel Combustion—Industrial Boilers, Internal Combustion Engines—Coal	212
Mobile—Commercial Marine Vessels	183
Industrial Processes—Not Elsewhere Classified	138
Fires—Wildfires	135
Industrial Processes—Chemical Manufacturing	123
Oil and Natural Gas Production and Natural Gas Processing and Transmission	65
Other SO_2 Sources [86]	551
Total SO_2 Emissions	2,726

Emissions from the 2017 NEI (released April 2020). **Note:** Totals may not sum due to rounding.

Table 11 below presents total VOC and SO_2 emissions from oil and natural gas production through transmission and storage, for the year 2017, in kt. The contribution to the total anthropogenic VOC emissions budget from the oil and gas sector has been increasing in recent NEI cycles. In the 2017 NEI, the oil and gas sector makes up about 25 percent of the total VOC emissions from anthropogenic sources. The SO_2 emissions have been declining in just about every anthropogenic sector, but the oil and gas sector is an exception where SO_2 emissions have been slightly increasing or remaining steady in some cases in recent years.

TABLE 11—U.S. VOC AND SO_2 EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[kt]

Sector	VOC	SO_2
Oil and Natural Gas Production	2,478	41
Natural Gas Processing	12	23
Natural Gas Transmission and Storage	14	1

Emissions from the 2017 NEI, (published April 2020), in kt (or thousand metric tons). **Note:** Totals may not sum due to rounding.

[85] Other sources include remaining sources emitting less than 1,000 kt VOC in 2017.

[86] Other sources include remaining sources emitting less than 100 kt SO_2 in 2017.

IV. Statutory Background and Regulatory History

A. Statutory Background of CAA Sections 111(b), 111(d) and General Implementing Regulations

The EPA's authority for this rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. This section requires the EPA to list source categories to be regulated, establish standards of performance for air pollutants emitted by new sources in that source category, and establish EG for States to establish standards of performance for certain pollutants emitted by existing sources in that source category.

Specifically, CAA section 111(b)(1)(A) requires that a source category be included on the list for regulation 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. 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 requirements) the Administrator determines has been adequately demonstrated.'' As long recognized by the D.C. Circuit, ''[b]ecause Congress did not assign the specific weight the Administrator should accord each of these factors, the Administrator is free to exercise his discretion in this area.'' *New York* v. *Reilly,* 969 F.2d 1147, 1150 (D.C. Cir. 1992). *See also Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (''*Lignite Energy Council*'') (''Because section 111 does not set forth the weight that be [sic] should assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them'').

In determining whether a given system of emission reduction qualifies as ''the best system of emission reduction . . . adequately demonstrated,'' or ''BSER,'' CAA section 111(a)(1) requires that the EPA take into account, among other factors, ''the cost of achieving such reduction.'' As described in the proposal [87] for the 2016 Rule (85 FR 35824, June 3, 2016), the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) has stated that in light of this provision, the EPA may not adopt a standard the cost of which would be ''exorbitant,'' [88] ''greater than the industry could bear and survive,'' [89] ''excessive,'' [90] or ''unreasonable.'' [91] These formulations appear to be synonymous, and for convenience, in this rulemaking, as in previous rulemakings, we will use reasonableness as the standard, so that a control technology may be considered the ''best system of emission reduction . . . adequately demonstrated'' if its costs are reasonable, but cannot be considered the BSER if its costs are unreasonable. See 80 FR 64662, 64720–21 (October 23, 2015).

CAA section 111(a) does not provide specific direction regarding what metric or metrics to use in considering costs, affording the EPA considerable discretion in choosing a means of cost consideration.[92] In this rulemaking, we evaluated whether a control cost is reasonable under a number of approaches that we find appropriate for assessing the types of controls at issue. For example, in evaluating controls for reducing VOC and methane emissions from new sources, we considered a control's cost effectiveness under both a ''single pollutant cost-effectiveness'' approach and a ''multipollutant cost-effectiveness'' approach, in order to appropriately take into account that the systems of emission reduction considered in this rule typically achieve reductions in multiple pollutants at once and secure a multiplicity of climate and public health benefits.[93] We also evaluated costs at a sector level by assessing the projected new capital expenditures required under the proposal (compared to overall new capital expenditures by the sector) and the projected compliance costs (compared to overall annual revenue for the sector) if the rule were to require such controls. For a detailed discussion of these cost approaches, please see section IX of the proposal preamble.

As defined in CAA section 111(a), the ''standard of performance'' that the EPA develops, based on the BSER, is expressed as a performance level (typically, a rate-based standard). CAA section 111(b)(5) precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard.

CAA section 111(h)(1) authorizes the Administrator to promulgate ''a design, equipment, work practice, or operational standard, or combination thereof'' if in his or her judgment, ''it is not feasible to prescribe or enforce a standard of performance.'' CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is ''not feasible,'' such as, when the pollutant cannot be emitted through a conveyance designed to emit or capture the pollutant, or when there is no practicable measurement methodology for the particular class of sources.[94] CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards unless the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard.

As mentioned above, once the EPA lists a source category under CAA section 111(b)(1)(A), CAA section 111(b)(1)(B) provides the EPA discretion to determine the pollutants and sources to be regulated. In addition, concurrent with the 8-year review (and though not a mandatory part of the 8-year review), the EPA may examine whether to add standards for pollutants or emission

[87] 80 FR 56593, 56616 (September 18, 2015).

[88] *Lignite Energy Council,* 198 F.3d at 933.

[89] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

[90] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[91] *Id.*

[92] See, *e.g., Husqvarna AB* v. *EPA,* 254 F.3d 195, 200 (D.C. Cir. 2001) (where CAA section 213 does not mandate a specific method of cost analysis, the EPA may make a reasoned choice as to how to analyze costs).

[93] We believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. The EPA has considered similar approaches in the past when considering multiple pollutants that are controlled by a given control option. See *e.g.,* 80 FR 56616–56617; 73 FR 64079–64083 and EPA Document ID Nos. EPA–HQ–OAR–2004–0022–0622, EPA–HQ–OAR–2004–0022–0447, EPA–HQ–OAR–2004–0022–0448.

[94] The EPA notes that design, equipment, work practice or operational standards established under CAA section 111(h) (commonly referred to as ''work practice standards'') reflect the ''best technological system of continuous emission reduction'' and that this phrasing differs from the ''best system of emission reduction'' phrase in the definition of ''standard of performance'' in CAA section 111(a)(1). Although the differences in these phrases may be meaningful in other contexts, for purposes of evaluating the sources and systems of emission reduction at issue in this rulemaking, the EPA has applied these concepts in an essentially comparable manner.

sources not currently regulated for that source category.

Once the EPA establishes NSPS in a particular source category, the EPA is required in certain circumstances to issue EG to reduce emissions from existing sources in that same source category. Specifically, CAA section 111(d) requires that the EPA prescribe regulations to establish procedures under which States submit plans to establish, implement, and enforce standards of performance for existing sources for certain air pollutants to which a Federal NSPS would apply if such existing source were a new source. The EPA addresses this CAA requirement both through its promulgation of general implementing regulations for section 111(d) as well as specific EG. The EPA first published general implementing regulations in 1975, 40 FR 53340 (November 17, 1975) (codified at 40 CFR part 60, subpart B), and has revised its section 111(d) implementing regulations several times, most recently on July 8, 2019, 84 FR 32520 (codified at 40 CFR part 60, subpart Ba).[95] In accordance with CAA section 111(d), States are required to submit plans pursuant to these regulations to establish standards of performance for existing sources for any air pollutant: (1) The emission of which is subject to a Federal NSPS; and (2) which is neither a pollutant regulated under CAA section 108(a) (*i.e.,* criteria pollutants such as ground-level ozone and particulate matter, and their precursors, like VOC) [96] or a HAP regulated under CAA section 112. See also definition of ''designated pollutant'' in 40 CFR 60.21a(a). The EPA's general implementing regulations use the term ''designated facility'' to identify those existing sources that may be subject to regulation under this provision of CAA section 111(d). See 40 CFR 60.21a(b).

While States are authorized to establish standards of performance for designated facilities, there is a fundamental obligation under CAA section 111(d) that such standards of performance reflect the degree of emission limitation achievable through the application of the BSER, as determined by the Administrator. This obligation derives from the definition of ''standard of performance'' under CAA section 111(a)(1), which makes no distinction between new-source and existing-source standards. The EPA identifies the degree of emission limitation achievable through application of the BSER as part of its EG. See 40 CFR 60.22a(b)(5). While standards of performance must generally reflect the degree of emission limitation achievable through application of the BSER, CAA section 111(d)(1) also requires that the EPA regulations permit the States, in applying a standard of performance to a particular source, to take into account the source's remaining useful life and other factors.

After the EPA issues final EG per the requirements under CAA section 111(d) and 40 CFR part 60, subpart Ba, States are required to submit plans that establish standards of performance for the designated facilities as defined in the EPA's guidelines and that contain other measures to implement and enforce those standards. The EPA's final EG issued under CAA section 111(d) do not impose binding requirements directly on sources, but instead provide requirements for States in developing their plans and criteria for assisting the EPA when judging the adequacy of such plans. Under CAA section 111(d), and the EPA's implementing regulations, a State must submit its plan to the EPA for approval, the EPA will evaluate the plan for completeness in accordance with enumerated criteria, and then will act on that plan via a rulemaking process to either approve or disapprove the plan in whole or in part. If a State does not submit a plan, or if the EPA does not approve a State's plan because it is not ''satisfactory,'' then the EPA must establish a Federal plan for that State.[97] If EPA approves a State's plan, the provisions in the state plan become federally enforceable against the designated facility responsible for compliance in the same manner as the provisions of an approved State implementation plan under CAA section 110. If no designated facility is located within a State, the State must submit to the EPA a letter certifying to that effect in lieu of submitting a State plan. See 40 CFR 60.23a(b).

Designated facilities located in Indian country would not be addressed by a State's CAA section 111(d) plan. Instead, an eligible Tribe that has one or more designated facilities located in its area of Indian country [98] would have the opportunity, but not the obligation, to seek authority and submit a plan that establishes standards of performance for those facilities on its Tribal lands.[99] If a Tribe does not submit a plan, or if the EPA does not approve a Tribe's plan, then the EPA has the authority to establish a Federal plan for that Tribe.[100]

B. What is the regulatory history and litigation background of NSPS and EG for the oil and natural gas industry?

1. 1979 Listing of Source Category

Subsequent to the enactment of the CAA of 1970, the EPA took action to develop standards of performance for new stationary sources as directed by Congress in CAA section 111. By 1977, the EPA had promulgated NSPS for a total of 27 source categories, while NSPS for an additional 25 source categories were then under development.[101] However, in amending the CAA that year, Congress expressed dissatisfaction that the EPA's pace was too slow. Accordingly, the 1977 CAA Amendments included a new subsection (f) in section 111, which specified a schedule for the EPA to list additional source categories under CAA section 111(b)(1)(A) and prioritize them for regulation under CAA section 111(b)(1)(B).

In 1979, as required by CAA section 111(f), the EPA published a list of source categories, which included ''*Crude Oil and Natural Gas Production,*'' for which the EPA would promulgate standards of performance under CAA section 111(b). See *Priority List and Additions to the List of Categories of Stationary Sources,* 44 FR 49222 (August 21, 1979) (''1979 Priority List''). That list included, in the order of priority for promulgating standards, source categories that the EPA Administrator had determined, pursuant to CAA section 111(b)(1)(A), contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. See 44 FR 49223 (August 21, 1979); see also 49 FR 2636–37 (January 20, 1984).

[95] Subpart Ba provides for the applicability of its provisions upon final publication of an EG if such EG is published after July 8, 2019. § 60.20a(a). The EPA acknowledges that the D.C. Circuit has vacated certain timing provisions within subpart Ba. *Am. Lung Assoc.* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021), *petition for cert. pending,* No. 20–1778 (filed June 23, 2001) (*Am. Lung Assoc.*). However, the court did not vacate the applicability provision, therefore subpart Ba applies to any EG finalized from this proposal. The Agency plans to undertake rulemaking to address the provisions vacated under the court's decision in the near future.

[96] VOC are not listed as CAA section 108(a) pollutants, but they are regulated precursors to photochemical oxidants (*e.g.,* ozone) and particulate matter (PM), both of which are listed CAA section 108(a) pollutants, and VOC therefore fall within the CAA 108(a) exclusion. Accordingly, promulgation of NSPS for VOC does not trigger the application of CAA section 111(d).

[97] CAA section 111(d)(2)(A).

[98] The EPA is aware of many oil and natural gas operations located in Indian Country.

[99] See 40 CFR part 49, subpart A.

[100] CAA section 111(d)(2)(A).

[101] See 44 FR 49222 (August 21, 1979).

2. 1985 NSPS for VOC and SO_2 Emissions From Natural Gas Processing Units

On June 24, 1985 (50 FR 26122), the EPA promulgated NSPS for the Crude Oil and Natural Gas source category that addressed VOC emissions from equipment leaks at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), the EPA promulgated additional NSPS for the source category to regulate SO_2 emissions from onshore natural gas processing plants (40 CFR part 60, subpart LLL).

3. 2012 NSPS OOOO Rule and Related Amendments

In 2012, pursuant to its duty under CAA section 111(b)(1)(B) to review and, if appropriate, revise the 1985 NSPS, the EPA published the final rule, ''Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution,'' 77 FR 49490 (August 16, 2012) (40 CFR part 60, subpart OOOO) (''2012 NSPS OOOO''). The 2012 rule updated the SO_2 standards for sweetening units and the VOC standards for equipment leaks at onshore natural gas processing plants. In addition, it established VOC standards for several oil and natural gas-related operations emission sources not covered by 40 CFR part 60, subparts KKK and LLL, including natural gas well completions, centrifugal and reciprocating compressors, certain natural gas operated pneumatic controllers in the production and processing segments of the industry, and storage vessels in the production, processing, and transmission and storage segments.

In 2013, 2014, and 2015 the EPA amended the 2012 NSPS OOOO rule in order to address implementation of the standards. ''Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards,'' 78 FR 58416 (September 23, 2013) (''2013 NSPS OOOO'') (concerning storage vessel implementation); ''Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards,'' 79 FR 79018 (December 31, 2014) (''2014 NSPS OOOO'') (concerning well completion); ''Oil and Natural Gas Sector: Definitions of Low Pressure Gas Well and Storage Vessel,'' 80 FR 48262 (August 12, 2015) (''2015 NSPS OOOO'') (concerning low pressure gas wells and storage vessels).

The EPA received petitions for both judicial review and administrative reconsiderations for the 2012, 2013, and 2014 NSPS OOOO rules. The EPA denied reconsideration for some issues, see ''Reconsideration of the Oil and Natural Gas Sector: New Source Performance Standards; Final Action,'' 81 FR 52778 (August 10, 2016), and, as noted below, granted reconsideration for other issues. As explained below, all litigation related to NSPS OOOO is currently in abeyance.

4. 2016 NSPS OOOOa Rule and Related Amendments

Regulatory action. 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,'' at 81 FR 35824 (40 CFR part 60, subpart OOOOa) (''2016 Rule'' or ''2016 NSPS OOOOa'').[102] [103] The 2016 NSPS OOOOa rule established NSPS for sources of GHGs and VOC emissions for certain equipment, processes, and operations across the Oil and Natural Gas Industry, including in the transmission and storage segment. 81 FR at 35832. The EPA explained that the 1979 listing identified the source category broadly enough to include that segment and, in the alternative, if the listing had limited the source category to the production and processing segments, the EPA affirmatively expanded the source category to include the transmission and storage segment on grounds that operations in those segments are a sequence of functions that are interrelated and necessary for getting the recovered gas ready for distribution. 81 FR at 35832. In addition, because this rule was the first time that the EPA had promulgated NSPS for GHG emissions from the Crude Oil and Natural Gas source category, the EPA predicated those NSPS on a determination that it had a rational basis to regulate GHG emissions from the source category. 81 FR at 35843. In response to comments, the EPA explained that it was not required to make an additional pollutant-specific finding that GHG emissions from the source category contribute significantly to dangerous air pollution, but in the alternative, the EPA did make such a finding, relying on the same information that it relied on when determining that it had a rational basis to promulgate a GHGs NSPS. 81 FR at 35843.

Specifically, the 2016 NSPS OOOOa addresses the following emission sources:

- Sources that were unregulated under the 2012 NSPS OOOO (hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations);
- Sources that were regulated under the 2012 NSPS OOOO for VOC emissions, but not for GHG emissions (hydraulically fractured gas well completions and equipment leaks at natural gas processing plants); and
- Certain equipment that is used across the source category, of which the 2012 NSPS OOOO regulated emissions of VOC from only a subset (pneumatic controllers, centrifugal compressors, and reciprocating compressors, with the exception of those compressors located at well sites).

On March 12, 2018 (83 FR 10628), the EPA finalized amendments to certain aspects of the 2016 NSPS OOOOa requirements for the collection of fugitive emission components at well sites and compressor stations, specifically (1) the requirement that components on a delay of repair must conduct repairs during unscheduled or emergency vent blowdowns, and (2) the monitoring survey requirements for well sites located on the Alaska North Slope.

Petitions for judicial review and to reconsider. Following promulgation of the 2016 NSPS OOOOa rule, several states and industry associations challenged the rule in the D.C. Circuit. The Administrator also received five petitions for reconsideration of several provisions of the final rule. Copies of the petitions are posted in Docket ID No. EPA–HQ–OAR–2010–0505.[104] As noted below, the EPA granted reconsideration as to several issues raised with respect to the 2016 NSPS OOOOa rule and finalized certain modifications discussed in the next section. As explained below, all litigation challenging the 2016 NSPS OOOOa rule is currently stayed.

5. 2020 Policy and Technical Rules

Regulatory action. In September 2020, the EPA published two final rules to amend 2012 NSPS OOOO and 2016 NSPS OOOOa. The first is titled, ''Oil

[102] The June 3, 2016, rulemaking also included certain final amendments to 40 CFR part 60, subpart OOOO, to address issues on which the EPA had granted reconsideration.

[103] The EPA review which resulted in the 2016 NSPS OOOOa rule was instigated by a series of directives from then-President Obama targeted at reducing GHGs, including methane: The President's *Climate Action Plan* (June 2013); the President's *Climate Action Plan: Strategy to Reduce Methane Emissions* (''Methane Strategy'') (March 2014); and the President's goal to address, propose and set standards for methane and ozone-forming emissions from new and modified sources in the sector (January 2015, *https://obamawhitehouse.archives.gov/the-press-office/2015/01/14/fact-sheet-Administration-takes-steps-forward-climate-action-plan-anno-1*).

[104] See Docket ID Item Nos.: EPA–HQ–OAR–2010–0505–7682, EPA–HQ–OAR–2010–0505–7683, EPA–HQ–OAR–2010–0505–7684, EPA–HQ–OAR–2010–0505–7685, EPA–HQ–OAR–2010–0505–7686.

and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review.'' 85 FR 57018 (September 14, 2020). Commonly referred to as the 2020 Policy Rule, it first rescinded the regulations applicable to the transmission and storage segment on the basis that the 1979 listing limited the source category to the production and processing segments and that the transmission and storage segment is not ''sufficiently related'' to the production and processing segments, and therefore cannot be part of the same source category. 85 FR at 57027, 57029. In addition, the 2020 Policy Rule rescinded methane requirements for the industry's production and processing segments on two separate bases. The first was that such standards are redundant to VOC standards for these segments. 85 FR at 57030. The second was that the rule interpreted section 111 to require, or at least authorize the Administrator to require, a pollutant-specific ''significant contribution finding'' (SCF) as a prerequisite to a NSPS for a pollutant, and to require that such finding be supported by some identified standard or established set of criteria for determining which contributions are ''significant.'' 85 FR at 57034. The rule went on to conclude that the alternative significant-contribution finding that the EPA made in the 2016 Rule for GHG emissions was flawed because it accounted for emissions from the transmission and storage segment and because it was not supported by criteria or a threshold. 85 FR at 57038.[105]

Published on September 15, 2020, the second of the two rules is titled, ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration.'' Commonly referred to as the 2020 Technical Rule, this second rule made further amendments to the 2016 NSPS OOOOa following the 2020 Policy Rule to eliminate or reduce certain monitoring obligations and to address a range of issues in response to administrative petitions for reconsideration and other technical and implementation issues brought to the EPA's attention since the 2016 NSPS OOOOa rulemaking. Specifically, the 2020 Technical Rule exempted low-production well sites from fugitives monitoring (previously required semiannually), required semiannual monitoring at gathering and boosting compressor stations (previously quarterly), streamlined recordkeeping and reporting requirements, allowed compliance with certain equivalent State requirements as an alternative to NSPS fugitive requirements, streamlined the application process to request the use of new technologies to monitor for fugitive emissions, addressed storage tank batteries for applicability determination purposes and finalized several technical corrections. Because the 2020 Technical Rule was issued the day after the EPA's rescission of methane regulations in the 2020 Policy Rule, the amendments made in the 2020 Technical Rule applied only to the requirements to regulate VOC emissions from this source category. The 2020 Policy Rule amended 40 CFR part 60, subparts OOOO and OOOOa, as finalized in 2016. The 2020 Technical Rule amended the 40 CFR part 60, subpart OOOOa, as amended by the 2020 Policy Rule.

Petitions to reconsider. The EPA received three petitions for reconsideration of the 2020 rulemakings. Two of the petitions sought reconsideration of the 2020 Policy Rule. As discussed below, on June 30, 2021, the President signed into law S.J. Res. 14, a joint resolution under the CRA disapproving the 2020 Policy Rule, and as a result, the petitions for reconsideration on the 2020 Policy Rule are now moot. All three petitions sought reconsideration of certain elements of the 2020 Technical Rule.

Litigation. Several States and non-governmental organizations challenged the 2020 Policy Rule as well as the 2020 Technical Rule. All petitions for review regarding the 2020 Policy Rule were consolidated into one case in the D.C. Circuit. *State of California, et al.* v. *EPA,* No. 20–1357. On August 25, 2021, after the enactment of the joint resolution of Congress disapproving the 2020 Policy Rule (explained in section VIII below), the court granted petitioners motion to voluntarily dismiss their cases. *Id.* ECF Dkt #1911437. All petitions for review regarding the 2020 Technical Rule were consolidated into a different case in the D.C. Circuit. *Environmental Defense Fund, et al.* v. *EPA,* No. 20–1360 (D.C. Cir.). On February 19, 2021, the court issued an order granting a motion by the EPA to hold in abeyance the consolidated litigation over the 2020 Technical Rule pending EPA's rulemaking actions in response to E.O. 13990 and pending the conclusion of EPA's potential reconsideration of the 2020 Technical Rule. *Id.* ECF Dkt #1886335.

As mentioned above, the EPA received petitions for judicial review regarding the 2012, 2013, and 2014 NSPS OOOO rules as well as the 2016 NSPS OOOOa rule. The challenges to the 2012 NSPS OOOO rule (as amended by the 2013 NSPS OOOO and 2014 NSPS OOOO rules) were consolidated. *American Petroleum Institute* v. *EPA,* No. 13–1108 (D.C. Cir.). The majority of those cases were further consolidated with the consolidated challenges to the 2016 NSPS OOOOa rule. *West Virginia* v. *EPA,* No. 16–1264 (D.C. Cir.), see specifically ECF Dkt #1654072. As such, *West Virginia* v. *EPA* includes challenges to the 2012 NSPS OOOO rule (as amended by the 2013 NSPS OOOO and 2014 NSPS OOOO rules) as well as challenges to the 2016 NSPS OOOOa rule.[106] On December 10, 2020, the court granted a joint motion of the parties in *West Virginia* v. *EPA* to hold that case in abeyance until after the mandate has issued in the case regarding challenges to the 2020 Technical Rule. *West Virginia* v. *EPA,* ECF Dkt #1875192.

C. Congressional Review Act (CRA) Joint Resolution of Disapproval

On June 30, 2021, the President signed into law a joint resolution of Congress, S.J. Res. 14, adopted under the CRA,[107] disapproving the 2020 Policy Rule.[108] By the terms of the CRA, the signing into law of the CRA joint resolution of disapproval means that the 2020 Policy Rule is ''treated as though [it] had never taken effect.'' 5 U.S.C. 801(f). As a result, the VOC and methane standards for the transmission and storage segment, as well as the methane standards for the production and processing segments—all of which had been rescinded in the 2020 Policy Rule—remain in effect. In addition, the EPA's authority and obligation to require the States to regulate existing sources of methane in the Crude Oil and

[105] Following the promulgation of the 2020 Policy Rule, the EPA promulgated a final rule that identified a standard or criteria for determining which contributions are ''significant,'' which the D.C. Circuit vacated. ''Pollutant-Specific Significant Contribution Finding for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories.'' 86 FR 2542 (Jan. 13, 2021), vacated by *California* v. *EPA,* No. 21–1035 (D.C. Cir.) (Order, April 5, 2021, Doc. #1893155).

[106] When the EPA issued the 2016 NSPS OOOOa rule, a challenge to the 2012 NSPS OOOO rule for failing to regulate methane was severed and assigned to a separate case, *NRDC* v. *EPA,* No. 16–1425 (D.C. Cir.), pending judicial review of the 2016 NSPS OOOOa in *American Petroleum Institute* v. *EPA,* No. 13–1108 (D.C. Cir.).

[107] The Congressional Review Act was adopted in Subtitle E of the Small Business Regulatory Enforcement Fairness Act of 1996.

[108] ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,'' 85 FR 57018 (Sept. 14, 2020) (''2020 Policy Rule'').

Natural Gas source category under section 111(d) of the CAA also remains in effect.

The CRA resolution did not address the 2020 Technical Rule; therefore, those amendments remain in effect with respect to the VOC standards for the production and processing segments in effect at the time of its enactment. As part of this rulemaking, in sections VIII and X the EPA discusses the impact of the CRA resolution, and identifies and proposes appropriate changes to reinstate the regulatory text that had been rescinded by the 2020 Policy Rule and to resolve any discrepancies in the regulatory text between the 2016 NSPS OOOOa Rule and 2020 Technical Rule.

V. Related Emissions Reduction Efforts

This section summarizes related State actions and other Federal actions regulating oil and natural gas emissions sources and summarizes industry and voluntary efforts to reduce climate change. The proposed NSPS OOOOb and EG OOOOc include specific measures that build on the experience and knowledge the Agency and industry have gained through voluntary programs, as well as the leadership of the States in pioneering new regulatory programs. The proposed NSPS OOOOb and EG OOOOc consists of reasonable, proven, cost-effective technologies and practices that reflect the evolutionary nature of the Oil and Natural Gas Industry and proactive regulatory and voluntary efforts. The EPA intends that the requirements proposed in this document will spur all industry stakeholders in all parts of the country to apply these readily available and cost-effective measures.

A. Related State Actions and Other Federal Actions Regulating Oil and Natural Gas Sources

The EPA recognizes that several States and other Federal agencies currently regulate the Oil and Natural Gas Industry. The EPA also recognizes that these State and other Federal agency regulatory programs have matured since the EPA began implementing its 2012 NSPS and subsequent 2016 NSPS. The EPA further acknowledges the technical innovations that the Oil and Natural Gas Industry has made during the past decade; this industry is fast-paced and constantly changing based on the latest technology. The EPA commends these efforts and recognizes States for their innovative standards, alternative compliance options, and implementation strategies. The EPA recognizes that any one effort will not be enough to address the increasingly dangerous impacts of climate change on public health and welfare and believes that consistent Federal regulation of the Crude Oil and Natural Gas source category plays an important role. To have a meaningful impact on climate change and its impact to human health and the environment, a multifaceted approach needs to be taken to ensure methane reductions will be realized. The EPA also recognizes that States and other Federal agencies regulate in accordance with their own authorities and within their own respective jurisdictions, and collectively do not fully address the range of sources and emission reduction measures contained in this proposal. Direct Federal regulation of methane from new sources combined with the approved State plans that are consistent with the EPA's EG for existing sources will bring national consistency to level the regulatory playing field, help promote technological innovation, and reduce both climate- and other health-harming pollution from a large number of sources that are either currently unregulated or where additional cost-effective reductions can be obtained. The EPA is committed to working within its authority to provide opportunities to align its programs with other existing State and Federal programs to reduce unnecessary regulatory redundancy where appropriate.

Among assessing various studies and emissions data, the EPA reviewed many current and proposed State regulatory programs to identify potential regulatory options that could be considered for BSER.[109] For example, the EPA reviewed California, Colorado, and Canadian regulations, as well as a pending proposed rule in New Mexico, that require non-emitting pneumatic devices at certain facilities and in certain circumstances. The EPA also examined California, Colorado, New Mexico (proposed), Pennsylvania, Wyoming, and the Bureau of Land Management (BLM) standards for liquids unloading events. Some of these States have led the way in regulating emissions sources that were not yet subject to requirements under the NSPS OOOOa. For example, Colorado requires the use of best management practices to minimize hydrocarbon emissions and the need for well venting associated with downhole well maintenance and liquids unloading, unless venting is necessary for safety. Other States, such as New Mexico, are evaluating similar requirements. Other States have requirements for emission sources currently regulated under NSPS OOOOa that are more stringent. For example, California and Colorado require continuous bleed natural gas-driven pneumatic controllers be non-emitting, with specified exceptions. We recognize that, in some cases, the EPA's proposed NSPS and/or EG may be more stringent than existing programs and, in other cases, may be less stringent than existing programs. After careful review and consideration of State regulatory programs in place and proposed State regulations, we are proposing NSPS and EG that, when implemented, will reduce emissions of harmful air pollutants, promote gas capture and beneficial use, and provide opportunity for flexibility and expanded transparency in order to yield a consistent and accountable national program that provides a clear path for States and other Federal agencies to further partner to ensure their programs work in conjunction with each other.

As an example of how the EPA strives to work with sources in States that have overlapping regulations for the Oil and Natural Gas Industry, the 2020 Technical Rule included approval of certain State programs as alternatives to certain requirements in the Federal NSPS. Subject to certain caveats, the EPA deemed certain fugitive emissions standards for well sites and compressor stations located in specific States equivalent to the NSPS in an effort to reduce any regulatory burden imposed by duplicative State and Federal regulations. See 40 CFR 60.5399a. The EPA worked extensively with States and reviewed many details of many State programs in this effort. Further, the 2020 Technical Rule amended 40 CFR part 60, subpart OOOOa, to incorporate a process that allows other States not already listed in 40 CFR 60.5399a to request approval of their fugitive monitoring program as an alternative to the NSPS. The EPA is proposing to include a similar request and approval process in NSPS OOOOb. Further, the EPA plans to work closely with States as they develop their State plans pursuant to the EG to look for opportunities to reduce unnecessary administrative burden imposed by redundant and duplicative regulatory requirements and help States that want to establish more stringent standards.

In addition to States, certain Federal agencies also regulate aspects of the oil and natural gas industry pursuant to their own authorities and have other established programs affecting the industry. The EPA believes that Federal regulatory actions and efforts will provide other environmental co-

[109] The NSPS OOOOb and EG TSD provides a high-level summary of the state programs that the agency assessed for purposes of this proposal.

benefits, but the EPA recognizes itself to be the Federal agency that has primary responsibility to protect human health and the environment and has been given the unique responsibility and authority by Congress to address the suite of harmful air pollutants associated with this source category. The EPA further believes that to have a meaningful impact to address the dangers of climate change, it is going to require an ''all hands-on deck'' effort across all States and all Federal agencies. The EPA has maintained an ongoing dialogue with its Federal partners during the development of this proposed rule to minimize any potential regulatory conflicts and to minimize confusion and regulatory burden on the part of owners and operators. The below description summarizes other agencies' regulations and other established Federal programs.

The U.S. Department of the Interior (DOI) regulates the extraction of oil and gas from Federal lands. Bureaus within the DOI include BLM and the Bureau of Ocean Energy Management (BOEM). The BLM manages the Federal Government's onshore subsurface mineral estate—about 700 million acres (30 percent of the U.S.)—for the benefit of the American public. The BLM maintains an oil and gas leasing program pursuant to the Mineral Leasing Act, the Mineral Leasing Act for Acquired Lands, the Federal Land Management and Policy Act, and the Federal Oil and Gas Royalty Management Act. Pursuant to a delegation of Secretarial authority, the BLM also oversees oil and gas operations on many Indian/Tribal leases. The BLM's oil and gas operating regulations are found in 43 CFR part 3160. An oil and gas operator's general environmental and safety obligations are found at 43 CFR 3162.5. The BLM does not directly regulate emissions for the purposes of air quality. However, BLM does regulate venting and flaring of natural gas for the purposes of preventing waste. The governing Resource Management Plan may require lessees to follow State and the EPA emissions regulations. An operator may be required to control/mitigate emissions as a condition of approval (COA) on a drilling permit. The need for such a COA is determined by the environmental review process. The BLM's rules governing the venting and flaring of gas are contained in NTL–4A, which was issued in 1980. Under NTL–4A, limitations on royalty-free venting and flaring constitute the primary mechanism for addressing the surface waste of gas. In 2016, the BLM replaced NTL–4A with a new rule governing venting and flaring (''Waste Prevention Rule''). In addition to restricting royalty-free flaring, the rule set emissions standards for tanks and pneumatic equipment and established LDAR requirements. In 2020, a U.S. District Court of Wyoming largely vacated that rule, thereby reinstating NTL–4A. More detailed information can be found at the BLM's website: *https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/methane-and-waste-prevention-rule.*

The BOEM manages the development of U.S. Outer Continental Shelf (offshore) energy and mineral resources. BOEM has air quality jurisdiction in the Gulf of Mexico [110] and the North Slope Borough of Alaska.[111] BOEM also has air jurisdiction in Federal waters on the Outer Continental Shelf 3–9 miles offshore (depending on State) and beyond. The Outer Continental Shelf Lands Act (OCSLA) section 5(a)(8) states, ''The Secretary of the Interior is authorized to prescribe regulations 'for compliance with the national ambient air quality standards pursuant to the CAA . . . to the extent that activities authorized under [the Outer Continental Shelf Lands Act] significantly affect the air quality of any State.' '' The EPA and States have the air jurisdiction onshore and in State waters, and the EPA has air jurisdiction offshore in certain areas. More detailed information can be found at BOEM's website: *https://www.boem.gov/.*

The U.S. Department of Transportation (DOT) manages the U.S. transportation system. Within DOT, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for regulating and ensuring the safe and secure transport of energy and other hazardous materials to industry and consumers by all modes of transportation, including pipelines. While PHMSA regulatory requirements for gas pipeline facilities have focused on human safety, which has attendant environmental co-benefits, the ''Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020'' (Pub. L. 116–260, Division R; ''PIPES Act of 2020''), which was signed into law on December 27, 2020, revised PHMSA organic statutes to emphasize the centrality of environmental safety and protection of the environment in PHMSA decision making. For example, the PHMSA's Office of Pipeline Safety ensures safety in the design, construction, operation, maintenance, and incident response of the U.S.' approximately 2.6 million miles of natural gas and hazardous liquid transportation pipelines. When pipelines are maintained, the likelihood of environmental releases like leaks are reduced.[112] In addition, the PIPES Act of 2020 contains several provisions that specifically address the minimization of releases of natural gas from pipeline facilities, such as a mandate that the Secretary of Transportation promulgate regulations related to gas pipeline LDAR programs. More detailed information can be found at PHMSA's website: *https://www.phmsa.dot.gov/.*

The U.S. Department of Energy (DOE) develops oil and natural gas policies and funds research on advanced fuels and monitoring and measurement technologies. Specifically, the Advanced Research Projects Agency-Energy (ARPA–E) program advances high-potential, high-impact energy technologies that are too early for private-sector investment. APRA–E awardees are unique because they are developing entirely new technologies. More detailed information can be found at ARPA–E's website: *https://arpa-e.energy.gov/.* Also, the U.S. Energy Information Administration (EIA) compiles data on energy consumption, prices, including natural gas, and coal. More detailed information can be found at the EIA's website: *https://www.eia.gov/.*

The U.S. Federal Energy Regulatory Commission (FERC) is an independent agency that regulates the interstate transmission of electricity, natural gas,[113] and oil.[114] FERC also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines as well as licensing hydropower projects. The Commission's responsibilities for the crude oil industry include the following: Regulation of rates and practices of oil pipeline companies engaged in interstate transportation; establishment of equal service conditions to provide shippers with equal access to pipeline transportation; and establishment of reasonable rates for transporting petroleum and petroleum products by pipeline. The Commission's responsibilities for the natural gas industry include the following: Regulation of pipeline, storage, and

[110] The CAA gave BOEM air jurisdiction west of 87.5° longitude in the Gulf of Mexico region.

[111] The Consolidated Appropriations Act of 2012 gave BOEM air jurisdiction in the North Slope Borough of Alaska.

[112] See Final Report on Leak Detection Study to PHMSA. December 10, 2012. *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16691/leak-detection-study.pdf.*

[113] *https://www.ferc.gov/industries-data/natural-gas.*

[114] *https://www.ferc.gov/industries-data/oil.*

liquefied natural gas facility construction; regulation of natural gas transportation in interstate commerce; issuance of certificates of public convenience and necessity to prospective companies providing energy services or constructing and operating interstate pipelines and storage facilities; regulation of facility abandonment, establishment of rates for services; regulation of the transportation of natural gas as authorized by the Natural Gas Policy Act and OCSLA; and oversight of the construction and operation of pipeline facilities at U.S. points of entry for the import or export of natural gas. FERC has no jurisdiction over construction or maintenance of production wells, oil pipelines, refineries, or storage facilities. More detailed information can be found at FERC's website: *https://www.ferc.gov/*.

B. Industry and Voluntary Actions To Address Climate Change

Separate from regulatory requirements, some owners or operators of facilities in the Oil and Natural Gas Industry choose to participate in voluntary initiatives. Specifically, over 100 oil and natural gas companies participate in the EPA Natural Gas STAR and Methane Challenge partnership programs. Owners or operators also participate in a growing number of voluntary programs unaffiliated with the EPA voluntary programs. The EPA is aware of at least 19 such initiatives.[115] Firms might participate in voluntary environmental programs for a variety of reasons, including attracting customers, employees, and investors who value more environmental-responsible goods and services; finding approaches to improve efficiency and reduce costs; and preparing for or helping inform future regulations.[116] [117]

The EPA's Natural Gas STAR Program started in 1993 and seeks to achieve methane emission reductions through implementation of cost-effective best practices and technologies. Partner companies document their voluntary emission reduction activities and can report their accomplishments to the EPA annually. Natural Gas STAR includes over 90 partners across the natural gas value chain. Through 2019 partner companies report having eliminated nearly 1.7 trillion cubic feet of methane emissions since 1993.

The EPA's Methane Challenge Program was launched in 2016 and expands on the Natural Gas STAR Program with ambitious, quantifiable commitments and detailed, transparent reporting and partner recognition. Annually Methane Challenge partners submit facility-level reports that characterize the methane emission sources at their facilities and detail voluntary actions taken to reduce methane emissions. The EPA emphasizes the importance of transparency with the publication of these facility-level data. Although this program includes nearly 70 companies from all segments of the industry, most partners operate in the transmission and distribution segments.

Other voluntary programs for the oil and natural gas industry are administered by diverse organizations, including trade associations and non-profits. While the field of voluntary initiatives continues to grow, it is difficult to understand the present, and potential future, impact these initiatives will have on reducing methane emissions as the majority of these initiatives publish aggregated program-level data. The EPA recognizes the voluntary efforts of industry in reducing methane emissions beyond what is required by current regulations and in significantly expanding the understanding of methane mitigation measures. While progress has been made, there is still considerable remaining need to further reduce methane emissions from the Industry.

VI. Environmental Justice Considerations, Implications, and Stakeholder Outreach

To better inform this proposed rulemaking, the EPA assessed the characteristics of populations living near sources affected by the rule and conducted extensive outreach to overburdened and underserved communities and to environmental justice organizations. During our engagement with communities, concerns were raised regarding health effects of air pollutants, implications of climate change on lifestyle changes, water quality, or extreme heat events, and accessibility to data and information regarding sources near their homes. The EPA then considered this input along with other stakeholder input in designing the proposed rule. For example, one key issue identified through stakeholder input is the use of cutting-edge technologies for methane detection that can allow for rapid detection of high-emitting sources. As described below, the EPA is proposing to allow the use of such technologies in this rule, alongside a rigorous fugitive emissions monitoring program that is based on traditional OGI technology. Another key concern the Agency heard is addressing large emission sources faster, which, in addition to seeking more information on new detection technologies, the EPA is proposing to address with more frequent monitoring at sites with more emissions. The EPA also heard that adjacent communities are concerned about health impacts, and the EPA is proposing rigorous guidelines for pollution sources at existing facilities, methane standards for storage vessels, strengthened and expanded standards for pneumatic controllers, and standards for liquids unloading events that will further reduce emissions of those pollutants. These are just a few examples of how this proposed rule provides benefits to communities; section XII provides a full explanation and rationale of the proposed actions.

E.O. 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples. 59 FR 7629 (February 16, 1994). Additionally, E.O. 13985 was signed in 2021 to advance racial equity and support underserved communities—including people of color and others who have been historically underserved, marginalized, and adversely affected by persistent poverty and inequality—through Federal Government actions. 86 FR 7009 (January 20, 2021). With respect to climate change, E.O. 14008, titled ''Tackling Climate Change at Home and Abroad,'' was signed on January 27, 2021, stating that climate considerations shall be an essential element of United States foreign policy and national security, working in partnership with foreign governments, States, territories, and local governments, and communities potentially impacted by climate change. The EPA defines environmental justice (EJ) as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to

[115] Highwood Emissions Management (2021). ''Voluntary Emissions Reduction Initiatives for Responsibly Sourced Oil and Gas.'' Available for download at: *https://highwoodemissions.com/research/*.

[116] Borck, J.C. and C. Coglianese (2009). ''Voluntary Environmental Programs: Assessing Their Effectiveness.'' Annual Review of Environment and Resources 34(1): 305–324.

[117] Brouhle, K., C. Griffiths, and A. Wolverton. (2009). ''Evaluating the role of EPA policy levers: An examination of a voluntary program and regulatory threat in the metal-finishing industry.'' Journal of Environmental Economics and Management. 57(2): 166–181.

mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies'' (*https://www.epa.gov/environmentaljustice*). In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution emitted from sources within the Oil and Natural Gas Industry that are addressed in this proposed rulemaking.

A. Environmental Justice and the Impacts of Climate Change

In 2009, under the *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act* (''Endangerment Finding'', 74 FR 66496), the Administrator considered how climate change threatens the health and welfare of the U.S. population.[118] As part of that consideration, she also considered risks to minority and low-income individuals and communities, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially disadvantaged communities, including those that have been historically marginalized or overburdened; individuals at vulnerable lifestages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; the disabled; those experiencing homelessness, mental illness, or substance abuse; and/or Indigenous or minority populations dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the USGCRP,[119] [120] the IPCC,[121] [122] [123] [124] the National Academies of Science, Engineering, and Medicine,[125] [126] and the EPA [127] add more evidence that the impacts of climate change raise potential EJ concerns. These reports conclude that less-affluent, traditionally marginalized and predominantly non-White communities can be especially vulnerable to climate change impacts because they tend to have limited resources for adaptation, are more dependent on climate-sensitive resources such as local water and food supplies, or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location (*e.g.,* African-American, Black, and Hispanic/Latino communities; Native Americans, particularly those living on Tribal lands and Alaska Natives), may be uniquely vulnerable to climate change health impacts in the U.S., as discussed below. In particular, the 2016 scientific assessment on the *Impacts of Climate Change on Human Health* [128] found with high confidence that vulnerabilities are place- and time-specific, lifestages and ages are linked to immediate and future health impacts, and social determinants of health are linked to greater extent and severity of climate change-related health impacts.

Per the NCA4, ''Climate change affects human health by altering exposures to heat waves, floods, droughts, and other extreme events; vector-, food- and waterborne infectious diseases; changes in the quality and safety of air, food, and water; and stresses to mental health and well-being.'' [129] Many health conditions such as cardiopulmonary or respiratory illness and other health impacts are associated with and exacerbated by an increase in GHGs and climate change outcomes, which is problematic as these diseases occur at higher rates within vulnerable communities. Importantly, negative public health outcomes include those that are physical in nature, as well as mental, emotional, social, and economic.

The scientific assessment literature, including the aforementioned reports, demonstrates that there are myriad ways

[118] Earlier studies and reports can be found at *https://www.epa.gov/cira/social-vulnerability-report.*

[119] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[120] USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. *http://dx.doi.org/10.7930/J0R49NQX.*

[121] Oppenheimer, M., M. Campos, R. Warren, J. Birkmann, G. Luber, B. O'Neill, and K. Takahashi, 2014: *Emergent risks and key vulnerabilities.* In: *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, Cambridge, United Kingdom and New York, NY, USA, pp. 1039–1099.

[122] Porter, J.R., L. Xie, A.J. Challinor, K. Cochrane, S.M. Howden, M.M. Iqbal, D.B. Lobell, and M.I. Travasso, 2014: *Food security and food production systems. In: 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, Cambridge, United Kingdom and New York, NY, USA, pp. 485–533.

[123] Smith, K.R., A. Woodward, D. Campbell-Lendrum, D.D. Chadee, Y. Honda, Q. Liu, J.M. Olwoch, B. Revich, and R. Sauerborn, 2014: Human health: impacts, adaptation, and co-benefits. In: 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, Cambridge, United Kingdom and New York, NY, USA, pp. 709–754.

[124] IPCC, 2018: Global Warming of 1.5 °C. An IPCC Special Report on the impacts of global warming of 1.5 °C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. In Press.

[125] National Research Council. 2011. *America's Climate Choices.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/12781.*

[126] National Academies of Sciences, Engineering, and Medicine. 2017. *Communities in Action: Pathways to Health Equity.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/24624.*

[127] EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430–R–21–003.

[128] USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.*

[129] Ebi, K.L., J.M. Balbus, G. Luber, A. Bole, A. Crimmins, G. Glass, S. Saha, M.M. Shimamoto, J. Trtanj, and J.L. White-Newsome, 2018: Human Health. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 539–571. doi: 10.7930/NCA4.2018.CH14.

in which these populations may be affected at the individual and community levels. Outdoor workers, such as construction or utility workers and agricultural laborers, who are frequently part of already at-risk groups, are exposed to poor air quality and extreme temperatures without relief. Furthermore, individuals within EJ populations of concern face greater housing and clean water insecurity and bear disproportionate economic impacts and health burdens associated with climate change effects. They also have less or limited access to healthcare and affordable, adequate health or homeowner insurance. The urban heat island effect can add additional stress to vulnerable populations in densely populated cities who do not have access to air conditioning.[130] Finally, resiliency and adaptation are more difficult for economically disadvantaged communities: They tend to have less liquidity, individually and collectively, to move or to make the types of infrastructure or policy changes necessary to limit or reduce the hazards they face. They frequently face systemic, institutional challenges that limit their power to advocate for and receive resources that would otherwise aid in resiliency and hazard reduction and mitigation.

The assessment literature cited in the EPA's 2009 Endangerment Finding, as well as *Impacts of Climate Change on Human Health,* also concluded that certain populations and people in particular stages of life, including children, are most vulnerable to climate-related health effects. The assessment literature produced from 2016 to the present strengthens these conclusions by providing more detailed findings regarding related vulnerabilities and the projected impacts youth may experience. These assessments—including the NCA4 (2018) and *The Impacts of Climate Change on Human Health in the United States* (2016)—describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to allergens, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More generally, these reports note that extreme weather and flooding can cause or exacerbate poor health outcomes by affecting mental health because of stress; contributing to or worsening existing conditions, again due to stress or also as a consequence of exposures to water and air pollutants; or by impacting hospital and emergency services operations.[131] Further, in urban areas in particular, flooding can have significant economic consequences due to effects on infrastructure, pollutant exposures, and drowning dangers. The ability to withstand and recover from flooding is dependent in part on the social vulnerability of the affected population and individuals experiencing an event.[132]

The Impacts of Climate Change on Human Health (USGCRP, 2016) also found that some communities of color, low-income groups, people with limited English proficiency, and certain immigrant groups (especially those who are undocumented) live with many of the factors that contribute to their vulnerability to the health impacts of climate change. While difficult to isolate from related socioeconomic factors, race appears to be an important factor in vulnerability to climate-related stress, with elevated risks for mortality from high temperatures reported for Black or African-American individuals compared to White individuals after controlling for factors such as air conditioning use. Moreover, people of color are disproportionately exposed to air pollution based on where they live, and disproportionately vulnerable due to higher baseline prevalence of underlying diseases such as asthma, so climate exacerbations of air pollution are expected to have disproportionate effects on these communities. Locations with greater health threats include urban areas (due to, among other factors, the ''heat island'' effect where built infrastructure and lack of green spaces increases local temperatures), areas where airborne allergens and other air pollutants already occur at higher levels, and communities experienced depleted water supplies or vulnerable energy and transportation infrastructure.

The recent EPA report on climate change and social vulnerability[133] examined four socially vulnerable groups (individuals who are low income, minority, without high school diplomas, and/or 65 years and older) and their exposure to several different climate impacts (air quality, coastal flooding, extreme temperatures, and inland flooding). This report found that Black and African-American individuals were 40% more likely to currently live in areas with the highest projected increases in mortality rates due to climate-driven changes in extreme temperatures, and 34% more likely to live in areas with the highest projected increases in childhood asthma diagnoses due to climate-driven changes in particulate air pollution. The report found that Hispanic and Latino individuals are 43% more likely to live in areas with the highest projected labor hour losses in weather-exposed industries due to climate-driven warming, and 50% more likely to live in coastal areas with the highest projected increases in traffic delays due to increases in high-tide flooding. The report found that American Indian and Alaska Native individuals are 48% more likely to live in areas where the highest percentage of land is projected to be inundated due to sea level rise, and 37% more likely to live in areas with high projected labor hour losses. Asian individuals were found to be 23% more likely to live in coastal areas with projected increases in traffic delays from high-tide flooding. Those with low income or no high school diploma are about 25% more likely to live in areas with high projected losses of labor hours, and 15% more likely to live in areas with the highest projected increases in asthma due to climate-driven increases in particulate air pollution, and in areas with high projected inundation due to sea level rise.

Impacts of Climate Change on Indigenous Communities. Indigenous communities face disproportionate risks from the impacts of climate change, particularly those communities impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Indigenous communities whose health, economic well-being, and cultural traditions depend upon the natural

[130] USGCRP, 2016.

[131] Ebi, K.L., J.M. Balbus, G. Luber, A. Bole, A. Crimmins, G. Glass, S. Saha, M.M. Shimamoto, J. Trtanj, and J.L. White-Newsome, 2018: Human Health. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 539–571. doi: 10.7930/NCA4.2018.CH14.

[132] National Academies of Sciences, Engineering, and Medicine 2019. Framing the Challenge of Urban Flooding in the United States. Washington, DC: The National Academies Press. *https://doi.org/10.17226/25381.*

[133] EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430–R–21–003.

environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The IPCC indicates that losses of customs and historical knowledge may cause communities to be less resilient or adaptable.[134] The NCA4 (2018) noted that while indigenous peoples are diverse and will be impacted by the climate changes universal to all Americans, there are several ways in which climate change uniquely threatens indigenous peoples' livelihoods and economies.[135] In addition, there can be institutional barriers (including policy-based limitations and restrictions) to their management of water, land, and other natural resources that could impede adaptive measures.

For example, indigenous agriculture in the Southwest is already being adversely affected by changing patterns of flooding, drought, dust storms, and rising temperatures leading to increased soil erosion, irrigation water demand, and decreased crop quality and herd sizes. The Confederated Tribes of the Umatilla Indian Reservation in the Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat. Housing and sanitary water supply infrastructure are vulnerable to disruption from extreme precipitation events. Confounding general Native American response to natural hazards are limitations imposed by policies such as the Dawes Act of 1887 and the Indian Reorganization Act of 1934, which ultimately restrict Indigenous peoples' autonomy regarding land-management decisions through Federal trusteeship of certain Tribal lands and mandated Federal oversight of management decisions. Additionally, NCA4 noted that Indigenous peoples are subjected to institutional racism effects, such as poor infrastructure, diminished access to quality healthcare, and greater risk of exposure to pollutants. Consequently, Native Americans often have disproportionately higher rates of asthma, cardiovascular disease, Alzheimer's disease, diabetes, and obesity. These health conditions and related effects (*e.g.,* disorientation, heightened exposure to $PM_{2.5}$, etc.) can all contribute to increased vulnerability to climate-driven extreme heat and air pollution events, which also may be exacerbated by stressful situations, such as extreme weather events, wildfires, and other circumstances.

NCA4 and IPCC's Fifth Assessment Report[136] also highlighted several impacts specific to Alaskan Indigenous Peoples. Coastal erosion and permafrost thaw will lead to more coastal erosion, rendering winter travel riskier and exacerbating damage to buildings, roads, and other infrastructure—impacts on archaeological sites, structures, and objects that will lead to a loss of cultural heritage for Alaska's indigenous people. In terms of food security, the NCA4 discussed reductions in suitable ice conditions for hunting, warmer temperatures impairing the use of traditional ice cellars for food storage, and declining shellfish populations due to warming and acidification. While the NCA4 also noted that climate change provided more opportunity to hunt from boats later in the fall season or earlier in the spring, the assessment found that the net impact was an overall decrease in food security.

B. Impacted Stakeholders

Based on analyses of exposed populations, the EPA has determined that this action, if finalized in a manner similar to what is proposed in this document, is likely to help reduce adverse effects of air pollution on minority populations, and/or low-income populations that have the potential for disproportionate impacts, as specified in E.O. 12898 (59 FR 7629, February 16, 1994) and referenced in E.O. 13985 (86 FR 7009, January 20, 2021). The EPA remains committed to engaging with communities and stakeholders throughout the development of this rulemaking and continues to invite comments on how the Agency can better achieve these goals through this action. For this proposed rule, we assessed emissions of HAP, criteria pollutants, and pollutants that cause climate change.

For HAP emissions, we estimated cancer risks and the demographic breakdown of people living in areas with potentially elevated risk levels by performing dispersion modeling of the most recent NEI data from 2017, which indicates nationwide emissions of approximately 110,000 tpy of over 40 HAP (including benzene, toluene, ethylbenzene, xylenes, and formaldehyde) from the Oil and Natural Gas Industry. Table 12 gives the risk and demographic results for the Oil and Natural Gas Industry from this screening-level assessment. We estimate there are 39,000 people with cancer risk greater than or equal to 100-in-1 million attributable to oil and natural gas sources, with a maximum estimated risk of 200-in-1 million occurring in three census blocks (10 people). We estimate there are about 143,000 people with estimated risk greater than or equal to 50-in-1 million, and about 6.8 million people with estimated cancer risk greater than 1-in-1 million. It is important to note that these estimates are subject to various types of uncertainty related to input parameters and assumptions, including emissions datasets, exposure modeling and the dose-response relationships.[137]

As shown in Table 12, Hispanic and Latino populations and young people (ages 0–17) are disproportionately represented in communities exposed to elevated cancer risks from oil and natural gas sources, while the proportion of people in other demographic groups with estimated risks above the specified levels is at or below the national average. The overall percent minority is about the same as the national average, but the percentage of people exposed to cancer risks greater than or equal to the 100-in-1 million and 50-in-1 million thresholds who are Hispanic or Latino is about 10 percentage points higher than the national average. The overall minority percentage is not elevated compared to the national average because the African-American percentage is much lower than the national average. The demographic group of people aged 0–17 is slightly higher than the national average.

[134] Porter et al., 2014: Food security and food production systems.

[135] Jantarasami, L.C., R. Novak, R. Delgado, E. Marino, S. McNeeley, C. Narducci, J. Raymond-Yakoubian, L. Singletary, and K. Powys Whyte, 2018: Tribes and Indigenous Peoples. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 572–603. doi: 10.7930/NCA4. 2018. CH15.

[136] Porter et al., 2014: Food security and food production systems.

[137] See 'Risk Report Template' at Docket ID No. EPA–HQ–OAR–2021–0317.

TABLE 12—CANCER RISK AND DEMOGRAPHIC POPULATION ESTIMATES FOR 2017 NEI NONPOINT OIL AND NATURAL GAS EMISSIONS

	Risks ≥100-in-1 million		Risks ≥50-in-1 million		Risks >1-in-1 million		Nationwide
Total Population	39,000		143,000		6,805,000		
	Population	%	Population	%	Population	%	%
Minority	13,268	34.1	52,154	36.5	2,010,161	29.5	39.9
African American	140	0.4	1,434	1.0	535,055	7.9	12.2
Native American	77	0.2	465	0.3	59,087	0.9	0.7
Other and Multiracial	1,443	3.7	5,148	3.6	323,397	4.8	8.2
Hispanic or Latino	11,608	29.9	45,107	31.6	1,092,621	16.1	18.8
Age 0–17	10,679	27.5	37,487	26.2	1,463,907	21.5	22.6
Age ≥65	4,272	11.0	17,188	12.0	1,085,067	15.9	15.7
Below the Poverty Level	2,000	5.1	13,455	9.4	902,472	13.2	13.4
Over 25 Without a High School Diploma	2,788	7.2	11,320	7.9	488,372	7.2	12.1
Linguistically Isolated	808	2.1	4,418	3.1	179,739	2.6	5.4

For criteria pollutants, we assessed exposures to ozone from Oil and Natural Gas Industry VOC emissions across races/ethnicities, ages, and sexes in a recent baseline (pre-control) air quality scenario. Annual air quality was simulated using a photochemical model for the year 2017, based on emissions from the most recent NEI. The analysis shows that the distribution of exposures for all demographic groups except Hispanic and Asian populations are similar to or below the national average or a reference population. Differences between exposures in Hispanic and Asian populations versus White or all populations are modest, and the results are subject to various types of uncertainty related to input parameters and assumptions.

In addition to climate and air quality impacts, the EPA also conducted analyses to characterize potential impacts on domestic oil and natural gas production and prices and to describe the baseline distribution of employment and energy burdens. Section XVI.d describes the results for our analysis of prices and production. For the distribution of baseline employment, we assessed the demographic characteristics of (1) workers in the oil and gas sector and (2) people living in oil and natural gas intensive communities.[138] Comparing workers in the oil and natural gas sector to workers in other sectors, oil and natural gas workers may have higher than average incomes, be more likely to have completed high school, and be disproportionately Hispanic. People in some oil and gas intensive communities concentrated in Texas, Oklahoma, and Louisiana have lower average income levels, lower rates of high school completion, and higher likelihood of being non-Whites or hispanic than people living in communities that are not oil and gas intensive. Regarding household energy burden, low-income households, Hispanic, and Black households' energy expenditures may comprise a disproportionate share of their total expenditures and income as compared to higher income, non-Hispanic, and non-Black households, respectively. Results are presented in detail in the RIA accompanying this proposal.

In a proximity analysis of Tribes living within 50 miles of affected sources, we found 112 unique Tribal lands (Federally recognized Reservations, Off-Reservation Trust Lands, and Census Oklahoma Tribal Statistical Areas (OTSA)) located within 50 miles of a source with 32 Tribes having one or more sources located on Tribal land.

Finally, the EPA has also analyzed prior enforcement actions related to air pollution from storage vessels, and identified improvements in air quality resulting from these actions as particularly important in communities with EJ concerns (identified using EJSCREEN).[139] In a 2021 analysis of resolved enforcement matters, the EPA determined that communities with EJ concerns experience a disproportionate level of air pollution burden from storage vessel emissions. Although only about 25 percent of storage vessels were located in these communities with EJ concerns, 67 percent of the total emission reductions of VOCs, methane, PM, and NO_X (about 95 million pounds) achieved through these enforcement resolutions occurred in communities with EJ concerns. This analysis suggests that the provisions of this proposed rule requiring installation of controls at storage vessels and monitoring and mitigation of fugitive emissions and malfunctions at storage vessels, would have particular benefits for these communities.

C. Outreach and Engagement

The EPA identified stakeholder groups likely to be interested in this action and engaged with them in several ways including through meetings, training webinars, and public listening sessions to share information with stakeholders about this action, on how stakeholders may comment on the proposed rule, and to hear their input about the industry and its impacts as we were developing this proposal. Specifically, on May 27, 2021, the EPA held a webinar-based training designed for communities affected by this rule.[140] This training provided an overview of the Crude Oil and Natural Gas Industry and how it is regulated and offered information on how to participate in the rulemaking process. The EPA also held virtual public listening sessions June 15 through June 17, 2021, and heard various community and health related themes from speakers who participated.[141] [142] Community themes

[138] For this analysis, oil and natural gas intensive communities are defined as the top 20% of communities with respect to the proportion of oil and natural gas workers.

[139] See Memorandum ''Analysis of Environmental Justice Impacts of EPA's Historical Oil and Gas Storage Vessel Enforcement Resolutions (40 CFR part 60 subpart OOOO and OOOOa),'' located at Docket ID No. EPA–HQ–OAR–2021–0317.

[140] *https://www.epa.gov/sites/default/files/2021-05/documents/us_epa_training_webinar_on_oil_and_natural_gas_for_communities.5.27.2021.pdf.*

[141] June 15, 2021 session: *https://youtu.be/T8XwDbf-B8g*; June 16, 2021 session: *https://www.youtube.com/watch?v=l23bKPF-5oc*; June 17,

Continued

included concerns about protecting communities adjacent to oil and gas activities, providing monitoring and data so communities know what is in the air they are breathing, and upholding Tribal trust responsibilities. Community speakers urged the EPA to adopt stringent measures to reduce oil and natural gas pollution, and frequently cited an analysis suggesting such measures could achieve reductions of 65 percent below 2012 levels by 2025.

Community Access to Emissions Information. Several stakeholders requested that the rule include requirements that provide communities with information, including fence line monitoring or ''better monitoring so people will know the air they are breathing.'' A few speakers expressed concerned about the correct placement of existing air monitors. Speakers from Texas described local air monitors monitoring meteorology and ozone, but not hazardous air pollutants, and called on the EPA to consider alternative monitoring for oil and natural gas sources such as fence-line monitors, along with guidance from the EPA to require monitors of oil and natural gas facilities in close proximity to parks, schools, and playgrounds.

Health Concerns in Adjacent Communities. Speakers raised concerns about impacts on frontline communities and those communities adjacent to oil and natural gas operations. These stakeholders called on the EPA to propose and promulgate stricter standards or alternative requirements for sources adjacent to urban communities and close to where people live and work. Several speakers used the term ''energy sacrifice zone'' when discussing the disproportionate impacts of oil and natural gas operations on frontline communities. Speakers advocated that when developing this regulatory effort, consultation with frontline communities is essential, and some speakers cited a Center for Investigative Reporting report stating that 30,000 children in Arlington, Texas, attend school within half a mile of active oil and gas sites. Speakers discussed concerns about methane as a formaldehyde precursor and related health effects and cited examples of health effects including hydraulic fracturing chemicals being measured in blood or urine; increases in nosebleeds in people in areas of oil and natural gas development; headaches and cancer. These speakers included teenagers from Pennsylvania, who said they live within 1 mile of 33 wellheads and 500 feet of a pipeline. Several people cited a February 2018 blowout and explosion in Belmont County, Ohio, that was reported to release 60,000 tons of methane in 20 days and said that is more than some countries emit in a year. Speakers also expressed related environmental concerns such as water contamination and fresh drinking water being diverted for hydraulic fracturing. One speaker urged that information on local water use be provided in languages other than English, stating that in Big Spring (Howard County), Texas, the local government only provided information to use tap water ''at your own risk'' in English.

Additional concerns raised by communities included: Local compressor stations having numerous planned and unplanned releases into adjacent communities, which appear to be during startup; whether the EPA will use a robust cost analysis to address the economic impacts of labor loss and gas costs resulting from any regulation; if plugged and abandoned wells included in this action, will this regulation apply to BLM land; will States be required to use the same emissions calculation used by the EPA for methane GWP; will there be disclosure of necessary data collection or technology to be used by the Oil and Natural Gas Industry to track and reduce methane emissions; and will the EPA consider the necessity of venting and flaring from a safety standpoint. Communities also discussed concerns about excess emissions from storage vessels and the need for clarifying the applicability of the standard in addition to improving enforceability and compliance at this type of facility.

In addition to the trainings and listening sessions, the EPA engaged with community leaders potentially impacted by this proposed action by hosting a meeting with EJ community leaders on May 14, 2021. As noted above, the EPA provided the public with factual information to help them understand the issues addressed by this action. We obtained input from the public, including communities, about their concerns about air pollution from the oil and gas industry, including receiving stakeholder perspectives on alternatives. The EPA considered and weighed information from communities as the agency developed this proposed action.

In addition to the engagement conducted prior to this proposal, the EPA is providing the public, including those communities disproportionately impacted by the burdens of pollution, opportunities to engage in the EPA's public comment period for this proposal, including by hosting public hearings. This public hearing will occur according to the schedule identified in the **DATES** and **SUPPLEMENTARY INFORMATION** section of this preamble to discuss:

- What impacts they are experiencing (*i.e.,* health, noise, smells, economic),
- How the community would like the EPA to address their concerns,
- How the EPA is addressing those concerns in the rulemaking, and
- Any other topics, issues, concerns, etc. that the public may have regarding this proposal.

For more information about the EPA's pre-proposal outreach activities, please see EPA Docket ID No. EPA–HQ–OAR–2021–0295. Please refer to EPA Docket ID No. EPA–HQ–OAR–2021–0317 for submitting public comments on this proposed rulemaking. For public input to be considered during the formal rulemaking, please submit comments on this proposed action to the formal regulatory docket at EPA Docket ID No. EPA–HQ–OAR–2021–0317 so that the EPA may consider those comments during the development of the final rule.

D. Environmental Justice Considerations

The EPA considered EJ implications in the development of this proposed rulemaking process, including the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income. As part of this process, the EPA engaged and consulted with frontline communities through interactions such as webinars, listening sessions and meetings. These opportunities gave the EPA a chance to hear directly from the public, especially overburdened and underserved communities, on the development of the proposed rule. The EPA considered these community concerns throughout our internal development process that resulted in this proposal which, if finalized in a manner similar to what is being proposed, will reduce emissions of harmful air pollutants, promote gas capture and beneficial use, and provide opportunity for flexibility and expanded transparency in order to yield a consistent and accountable national program. The EPA's proposed NSPS and EG are summarized in sections XI and XII below. Anticipated impacts of this action are discussed further in section XVI of this preamble.

In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider

2021 session: *https://www.youtube.com/watch?v=R2AZrmfuAXQ.*

[142] Full transcripts for the listening sessions are posted at EPA Docket ID No. EPA–HQ–OAR–2021–0295.

ways to protect them from adverse public health and environmental effects of air pollution emitted from sources within the Oil and Natural Gas Industry that are addressed in this proposed rulemaking. For these reasons, in section XIV.C the EPA is proposing to include an additional requirement associated with the adoption and submittal of State plans pursuant to EG OOOOc (in addition to the current requirements of Subpart Ba) by requiring States to meaningfully engage with members of the public, including overburdened and underserved communities, during the plan development process and prior to adoption and submission of the plan to the EPA. The EPA is proposing this specific meaningful engagement requirement to ensure that the State plan development process is inclusive, effective, and accessible to all.

Details of the EPA's assessment of EJ considerations can be found in the RIA for this action. The EPA seeks input on the EJ analyses contained in the RIA, as well as broader input on other health and environmental risks the Agency should assess in the comprehensive development of this proposed action. In particular, the EPA is soliciting comment on key assumptions underlying the EJ analysis as well as data and information that would enable the Agency to conduct a more nuanced analysis of HAP and criteria pollutant exposure and risk, given the inherent uncertainty regarding risk assessment. More broadly, the EPA seeks information, analysis, and comment on how the provisions of this proposed action would affect air pollution and health in communities with environmental justice concerns, and whether there are further provisions that EPA should consider as part of a supplemental proposal or a final rule that would enhance the health and environmental benefits of this rule for these communities.

VII. Other Stakeholder Outreach

A. Educating the Public, Listening Sessions, and Stakeholder Outreach

The EPA began the development of this proposed action to reduce methane and other harmful pollutants from new and existing sources in the Crude Oil and Natural Gas source category with a public outreach effort to gather a broad range of stakeholder input. This effort included: Opening a public docket for pre-proposal input; [143] holding training sessions providing overviews of the industry, the EPA's rulemaking process and how to participate in it; and convening listening sessions for the public, including a wide range of stakeholders. The EPA additionally held roundtables with State environmental commissioners through the Environmental Council of the States, and oil and gas commissioners and staff through the Interstate Oil and Gas Compact Commission (IOGCC), and met with non-governmental organizations (NGOs), industry, and the U.S. Climate Alliance, among others.[144]

In addition to the trainings and listening sessions noted in section VI above, on May 25 and 26, 2021, the EPA held webinar-based trainings designed for small business stakeholders [145] and Tribal nations.[146] The training provided an overview of the Oil and Natural Gas Industry and how it is regulated and offered information on how to participate in the rulemaking process. A combined total of more than 100 small business stakeholders and Tribal nations participated. During the training, small business stakeholders expressed interest in learning more about the EPA's plan to either modify the 2016 NSPS OOOOa or take more substantial action in this proposal. For Tribal nations, the EPA has assessed potential impacts on Tribal nations and populations and has engaged with Tribal stakeholders to hear concerns associated with air pollution emitted from sources within the Oil and Natural Gas Industry that are addressed in this proposed rulemaking. Tribal members mentioned the need for the EPA to uphold its trust responsibilities, propose and promulgate rules that protect disproportionately impacted communities, and asked that the EPA allocate resources for Tribal governments to implement regulations through Tribal air quality programs.

As noted above, the EPA also heard from a broad range of stakeholders during virtual public listening sessions held from June 15 through June 17, 2021,[147] which featured a total of 173 speakers.[148] Many speakers stressed the urgent need to address climate change and the importance of reducing methane pollution as part of the nation's overall response to climate change. In addition to the community perspectives described above, the Agency also heard from industry speakers who were generally supportive of the regulation and stressed the need to provide compliance flexibility and allow industry the ability to use cutting-edge tools, including measurement tools, to implement requirements. Technical comments from other speakers also focused on a need for robust methane monitoring and fugitive emissions monitoring, a need to strengthen standards for flares as a control for associated gas, and suggestions to improve compliance. The sections below provide additional details on the information presented by stakeholders during these listening sessions.

1. Technical Themes

Measurement and Monitoring. Stakeholders advocated that the EPA modernize the rule by employing next-generation tools for methane identification and quantification, particularly for large emission or ''super-emissions'' events. Stakeholders particularly focused on allowing the use of remote sensing to help industry more easily comply with monitoring requirements at well pads, which are numerous and geographically spread out in some States. Stakeholders specified the desire to use innovative remote sensing technologies to monitor fugitive emissions and large emission events, including aerial, truck-based, satellite, and continuous monitoring. Several speakers focused on the need for regular monitoring, repair, and reporting, including ambient air monitoring in oil and natural gas development areas, as well as suggesting that the EPA pursue more robust methane monitoring for fugitive emissions, ensure that repair is completed, and pursue robust monitoring and reporting to verify the efficacy of the regulations.

Implementation, Compliance, and Enforcement. Numerous stakeholders raised concerns about flaring of associated gas and advocated for more stringent standards to ensure that flares used as control devices perform effectively. One speaker, an OGI expert, noted seeing many flares that were not operating the way they were intended to and that were not adequately designed (*e.g.,* unlit flares and ignition gas not being close enough to the waste gas stream to properly ignite). The speaker suggested that the EPA consider the concept of 'thermal tuning' of flares by

[143] EPA Docket ID No. EPA–HQ–OAR–2021–0295.

[144] A full list of pre-proposal meetings the EPA participated in is included at EPA Docket ID No. EPA–HQ–OAR–2021–0317.

[145] *https://www.epa.gov/sites/default/files/2021-05/documents/oil_and_gas_training_webinar_small_businesses_05.25.21.pdf.*

[146] *https://www.epa.gov/sites/default/files/2021-05/documents/usepa_training_webinar_on_oil_and_natural_gas_for_tribes.5.26.2021.pdf.*

[147] June 15, 2021 session: *https://youtu.be/T8XwDbf-B8g;* June 16, 2021 session: *https://www.youtube.com/watch?v=l23bKPF-5oc;* June 17, 2021 session: *https://www.youtube.com/watch?v=R2AZrmfuAXQ.*

[148] Full transcripts for the listening sessions are posted in at EPA Docket ID No. EPA–HQ–OAR–2021–0295.

using OGI to see if a plume of unburned hydrocarbons extends downwind from the flare, to ensure that flares are actually operating effectively; the speaker suggested that this use of OGI could be done in conjunction with fugitive emissions monitoring to make sure controls are working. Stakeholders further emphasized the need for recordkeeping of any inspections that are made (*e.g.,* looking for flare damage from burned tips, lightning strikes). Some stakeholders also requested that the EPA consider reducing or eliminating flaring of associated gas and incentivizing capture. Lastly, one speaker raised concerns about flaring of associated gas in Texas and how flaring is permitted by the State. In response to these concerns, the EPA is proposing to reduce venting and flaring of associated gas and to require monitoring of flares to detect malfunctions. Further, the EPA is soliciting comment on whether to adopt additional measures to assure proper design and operation of control devices, including flares, as discussed in section XIII.

Stakeholders raised other implementation, compliance, and enforcement concerns, including calls for the EPA to develop rules that are easy to apply and implement given States' limited budgets. Stakeholders cautioned that ''flexibility'' in a rule can be interpreted as a ''loophole,'' and opined that a rule that sets clear and uniform expectations will help avoid confusion. At the same time, speakers stated that a ''prescriptive checklist'' does not work in today's environment and recommended that the EPA modernize the regulatory approach. Several speakers, including speakers from Texas and North Dakota, raised concerns about the limited enforcement capacity of local and State governments, as well as the EPA and its regional officials and stated that this may result in implementation gaps. Speakers called on the EPA to have a third-party verification or audit requirements for fugitive emissions and cited to Texas's requirement for third-party audits to evaluate operator LDAR programs for highly reactive VOC. Speakers also cited to the public-facing Environmental Defense Fund (EDF) methane map [149] with geotags of sources with observed hydrocarbon emissions, which provides operators an opportunity to respond to posted leak videos and measurements. Lastly, one speaker requested that the EPA not allow exemptions for start-up and shutdown emissions events. The EPA is soliciting comment on ways to utilize credible emissions information obtained from communities and others, as discussed in section XI.A.1.

Wells and Storage. Some stakeholders requested that the EPA consider a program for capping abandoned wells to ensure those wells are properly closed and not leaking. Speakers called on the EPA to consider abandoned and unplugged wells in the context of EJ communities adjacent to affected facilities and requested that the EPA incentivize appropriate well closure. In response to this input and to gather information that will be needed to inform possible future actions, the EPA is soliciting comment on ways to address abandoned wells, including potential closure requirements. See section XIII.B. Stakeholders also focused on marginal wells and asked that the EPA consider system-wide reductions be allowed, for example, at the basin level, and expressed challenges of retrofitting existing well sites and low production well sites where addition of control devices or closed vent systems would be necessary. Some speakers raised concern about ensuring that facilities are engineered for the basin or target formation from which they produce.

Job Creation. Some speakers stated that this rulemaking is a job creation rule and encouraged a ''next generation'' approach to methane standards, such as incentivizing continuous monitoring. Other speakers cited a study about job creation in the methane mitigation industry.[150]

Inventory, Loss Rates, and Methane Global Warming Potential. Several speakers criticized the EPA's emission inventories stating that the EPA is not using the correct data in its inventory, that the GHGI data is inaccurate because it relies on facility reporting of emissions from calculations and estimation methods rather than measurement and monitoring, and suggested that the EPA rely on monitoring and measurement of actual emissions and subsequently make the monitoring data publicly available. Speakers raised issues with differences in inventories across Federal agencies, contrasting DOE's Environmental Impact Statements and EPA's NEI. Stakeholders suggested that the EPA use data collected by EDF and other researchers, which calculated methane emissions to be 60 percent higher than the EPA's estimates.[151] Speakers also mentioned the amount of methane that is lost from wells each year, providing varying estimates of these emissions. Lastly, stakeholders called on the EPA to use the 20-year GWP for methane, instead of the 100-year value the agency uses.

2. Climate and Other Themes

Several speakers mentioned the effects of climate change from oil and natural gas methane emissions, such as impacts on farmland, wildfires, and transmission of tick-borne pathogens. Many speakers pointed out the extreme heat and drought that currently are affecting the western U.S. Stakeholders asked that the EPA examine the impacts of the Oil and Natural Gas Industry on small businesses that are not part of the regulated community, such as businesses that rely on outdoor recreation or water flow that could be affected by oil and natural gas operations. A speaker raised concerns about the impact of the industry on tourism, saying that 30 percent of their local economy relies on tourism and outdoor recreation. Lastly, a speaker discussed pipeline weatherization needs and suggested that the EPA and other Federal agencies account for seasonal variability.

In addition to the public listening sessions, on June 29, 2021, the EPA met with environmental commissioners and staff through the Environmental Council of the States (ECOS). Subsequently, on July 12, 2021, the EPA participated in a roundtable with members of the IOGCC. The discussions in both roundtables included air emissions monitoring technologies and interactions between the EPA's requirements and State rules. For the ECOS roundtable, the EPA also sought feedback on and implementation of the EPA's current NSPS; for the IOGCC roundtable, the EPA also requested feedback on compliance with the rules.

Key themes from both roundtables included the following: Allowing for the use of broad types of methane detection technologies; improving and streamlining the EPA's AMEL process, such as by structuring it so it could apply broadly rather than on a site-by-site basis; requests that expanded aspects of States' rules be deemed equivalent to the EPA's rule, and requests that the EPA's rule complement State regulations in a way that would not interrupt the work of State agencies requiring them to request State legislative approvals. Other common themes were requests that the rule

[149] *https://www.permianmap.org.*

[150] Stakeholders submitted the following studies to the pre-proposal docket: *https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0295-0016* and *https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0295-0017.*

[151] Alvarez et al. 2018. *Assessment of methane emissions from the U.S. oil and gas supply chain.* Science 13 Jul 2018: Vol. 361, Issue 6398, pp. 186–188.

provide flexibility and be easy to implement, particularly for marginal or low production wells owned by independent small businesses, and that the EPA coordinate its rules with those of other Federal agencies, notably the DOI's BLM.

Other input included the need to fill gaps by addressing additional opportunities to reduce emissions beyond the 2016 NSPS OOOOa, concerns about the complexity of the calculation for the potential to emit for storage vessels, a desire that the EPA's rule not slow momentum of voluntary efforts to reduce emissions, and a desire for regulations that recognize geographic differences.

B. EPA Methane Detection Technology Workshop

The EPA held a virtual public workshop on August 23 and 24, 2021, to hear perspectives on innovative technologies that could be used to detect methane emissions from the Oil and Natural Gas Industry.[152] The workshop focused on methane-sensing technologies that are not currently approved for use in the NSPS for the Oil and Natural Gas Industry, and how those technologies could be applied in the Crude Oil and Natural Gas sector. Panelists provided twenty-four live presentations during the workshop. The panelists all had firsthand experience evaluating innovative methane-sensing technologies or had used these technologies to identify methane emissions and presented about their experience. The live presentations were broken into six panel sessions, each focused on a particular topic, *e.g.,* satellite measurements, methane sensors, aerial technologies. At the end of each panel session, the set of panelists participated in a question-and-answer session. In addition to the live presentations, the workshop included a virtual exhibit hall for technology vendors to provide video presentations on their innovative technologies, with a focus on technology capability, applicability, and data quality. Forty-two vendors participated in the virtual vendor hall.

Nine hundred sixty stakeholders registered to participate in the workshop. The workshop was also livestreamed, so stakeholders who could not attend could watch the recorded livestream later at their convenience. The registrants included a wide range of stakeholders including, academics, methane detection technology end-user and vendors, governmental employees (local, State, and Federal), and NGOs.

C. How is this information being considered in this proposal?

The EPA's pre-proposal outreach effort was intended to gather stakeholder input to assist the Agency with developing this proposal.[153] The EPA recognizes that tackling the dangers of climate change will require an ''all-hands-on deck'' approach through regulatory, voluntary, and community programs and initiatives. Throughout the development of this proposed rule, the EPA considered the stakeholders' experiences and lessons learned to help inform how to better structure this proposal and consider ongoing challenges that will require continued collaboration with stakeholders. The EPA will continue to consider the information obtained in developing this proposal as we take the next steps on the proposed regulations.

With this proposal, the EPA seeks further input from the public and from all stakeholders affected by this rule. Throughout this action, unless noted otherwise, the EPA is requesting comments on all aspects of this proposal, including on several themes raised in the pre-proposal outreach (*e.g.,* innovative technologies for methane detection and quantification). Please see section XI.A.1 of this preamble for specific solicitations for comment regarding advanced measurement technologies and section XIII for solicitations for comments on additional emission sources. For public input to be considered on this proposal,[154] please submit comments on this proposed action to the regulatory docket at EPA Docket ID No. EPA–HQ–OAR–2021–0317 so that the EPA may consider those comments during the development of the final rule.

VIII. Legal Basis for Proposal Scope

The EPA proposes in this rulemaking to revise certain NSPS and to promulgate additional NSPS for both methane and VOC emissions from new oil and gas sources in the production, processing, transmission and storage segments of the industry; and to promulgate EG to require States to regulate methane emissions from existing sources in those segments. The large amount of methane emissions from the Oil and Natural Gas Industry—by far, the largest methane-emitting industry in the nation—coupled with the adverse effects of methane on the global climate compel immediate regulatory action. This section explains EPA's legal justification for proceeding with this proposed action, including regulating methane and VOCs from sources in all segments of the source category. The EPA first describes the history of our regulatory actions for oil and gas sources in 2016 and 2020—including the key legal interpretations and factual determinations made—as well as Congress's action in 2021 in response. The EPA then explains the implications of Congress's action and why we would come to the same conclusion even if Congress had not acted.

This proposal is in line with our 2016 NSPS OOOOa rule, which likewise regulated methane and VOCs from all three segments of the industry. The 2016 NSPS OOOOa rule explained that these three segments should be regulated as part of the same source category because they are an interrelated sequence of functions in which pollution is produced from the same types of sources that can be controlled by the same techniques and technologies. That rule further explained that the large amount of methane emissions, coupled with the adverse effects of GHG air pollution, met the applicable statutory standard for regulating methane emissions from new sources through NSPS. Furthermore, the rule explained, this regulation of methane emissions from new sources triggered the EPA's authority and obligation to set guidelines for States to develop standards to regulate the overwhelming majority of oil and gas sources, which the CAA categorizes as ''existing'' sources. In the 2020 Policy Rule, the Agency reversed course, concluding based upon new legal interpretations that the rule concluded the EPA had not made the proper determinations necessary to issue such regulations. This action eliminated the Agency's authority and obligation to issue EG for existing sources. In 2021, Congress adopted a joint resolution to disapprove the EPA's 2020 Policy Rule under the CRA. According to the terms of CRA, the 2020 Policy Rule is ''treated as though [it] had never taken effect,'' 5 U.S.C. 801(f), and as a result, the 2016 Rule is reinstated.

In disapproving the 2020 Policy Rule under the CRA, Congress explicitly rejected the 2020 Policy Rule interpretations and embraced EPA's

[152] *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.*

[153] The EPA opened a non-regulatory docket for stakeholder to submit early input. That early input can be found at EPA Docket I.D. Number EPA–HQ–OAR–2021–0295.

[154] Information submitted to the pre-proposal non-regulatory docket at Docket ID No. EPA–HQ–OAR–2021–0295 is not automatically part of the proposal record. For information and materials to be considered in the proposed rulemaking record, it must be resubmitted in the rulemaking docket at EPA Docket ID No. EPA–HQ–OAR–2021–0317.

rationales for the 2016 NSPS OOOOa rule. The House Committee on Energy & Commerce emphasized in its report that the source category ''is the largest industrial emitter of methane in the U.S.,'' and directed that ''regulation of emissions from new and existing oil and gas sources, including those located in the production, processing, and transmission and storage segments, is necessary to protect human health and welfare, including through combatting climate change, and to promote environmental justice.'' H.R. Rep. No. 117–64, 3–5 (2021) (House Report). A statement from the Senate cosponsors likewise underscored that ''methane is a leading contributing cause of climate change,'' whose ''emissions come from all segments of the Oil and Gas Industry,'' and stated that ''we encourage EPA to strengthen the standards we reinstate and aggressively regulate methane and other pollution emissions from new, modified, and existing sources throughout the production, processing, transmission and storage segments of the Oil and Gas Industry under section 111 of the CAA.'' 167 Cong. Rec. S2282 (April 28, 2021) (statement by Sen. Heinrich) (Senate Statement).[155] The Senators concluded with a stark statement: ''The welfare of our planet and of our communities depends on it.'' *Id.* at S2283.

This proposal comports with the EPA's CAA section 111 obligation to reduce dangerous pollution and responds to the urgency expressed by the current Congress. With this proposal, the EPA is taking additional steps in the regulation of the Crude Oil and Natural Gas source category to protect human health and the environment. Specifically, the agency is proposing to revise certain of those NSPS, to add NSPS for additional sources, and to propose EG that, if finalized, would impose a requirement on States to regulate methane emissions from existing sources. As the EPA explained in the 2016 Rule, this source category collectively emits massive quantities of the methane emissions that are among those driving the grave and growing threat of climate change, particularly in the near term. 81 FR 35834, June 3, 2016. As discussed in section III above, since that time, the science has repeatedly confirmed that climate change is already causing dire health, environmental, and economic impacts in communities across the United States.

Because the 2021 CRA resolution automatically reinstated the 2016 Rule, which itself determined that the Crude Oil and Natural Gas Source Category included the transmission and storage segment and that regulation of methane emissions was justified, the EPA is authorized to take the regulatory actions proposed in this rule. As explained below, we are reaffirming those determinations as clearly authorized under any reasonable interpretation of section 111. Because the reinstatement of the 2016 Rule provides the only necessary predicate for this rule, and because, as described, the interpretations underlying this rule are sound, the EPA is not reopening them here.

A. Recent History of the EPA's Regulation of Oil and Gas Sources and Congress's Response

1. 2016 NSPS OOOOa Rule

As described above, the 2016 NSPS OOOOa rule extended the NSPS for VOCs for new sources in the Crude Oil and Natural Gas source category and also promulgated NSPS for methane emissions from new sources. This rule contained several interpretations that were the bases for these actions, and that are important for present purposes. First, the EPA confirmed its position in the 2012 NSPS OOOO rule that the scope of the oil and gas source category included the transmission and storage segment, in addition to the production and processing segments that the EPA had regulated since 1984. The agency stated that it believed these segments were included in the initial listing of the source category, and to the extent they were not, the agency determined to add them as appropriately encompassed within the regulated source category. The EPA based this latter conclusion on the structure of the industry. In particular, the EPA emphasized that ''[o]perations at production, processing, transmission, and storage facilities are a sequence of functions that are interrelated and necessary for getting the recovered gas ready for distribution,'' and further explained, ''[b]ecause they are interrelated, segments that follow others are faced with increases in throughput caused by growth in throughput of the segments preceding (*i.e.,* feeding) them.'' 81 FR 35832, June 3, 2016. The EPA also recognized ''that some equipment (*e.g.,* storage vessels, pneumatic pumps and compressors) are used across the oil and natural gas industry.'' *Id.* Having made clear that the Crude Oil and Natural Gas source category includes the transmission and storage segment, the EPA proceeded to promulgate NSPS for sources in that segment. *Id.* at 35826.

Second, in promulgating NSPS for methane emissions for new sources in the source category, the EPA explained its decision to regulate GHGs for the first time from the source category. Noting that the plain language of CAA section 111 requires a significant-contribution analysis only when EPA regulates a new source category, not a new pollutant, the Agency stated that it ''interprets CAA section 111(b)(1)(B) to provide authority to establish a standard for performance for any pollutant emitted by that source category as long as the EPA has a rational basis for setting a standard for the pollutant.'' 81 FR 35842, June 3, 2016. In the alternative, if a rational-basis analysis were deemed insufficient, the EPA explained that it also concluded that GHG emissions, in the form of methane emissions, from the regulated Crude Oil and Natural Gas source category significantly contribute to dangerous pollution. *Id.* at 81 FR 35843, and 35877. In making the rational basis and alternative significant contribution findings, the EPA focused on ''the high quantities of methane emissions from the Crude Oil and Natural Gas source category.'' *Id.* The EPA emphasized, among other things, that ''[t]he Oil and Natural Gas source category is the largest emitter of methane in the U.S., contributing about 29 percent of total U.S. methane emissions.'' *Id.* The EPA added that ''[t]he methane that this source category emits accounts for 3 percent of all U.S. GHG emissions . . . [and] GWP-weighted emissions of methane from these sources are larger than emissions of all GHGs from about 150 countries.'' *Id.* The EPA concluded that ''the[se] facts . . . along with prior EPA analysis'' concerning the effect of GHG air pollution on public health and welfare, ''including that found in the 2009 Endangerment Finding, provide a rational basis for regulating GHG emissions from affected oil and gas sources . . .'' as well as for concluding in the alternative that oil and gas methane significantly contributes to dangerous pollution. *Id.* at 35843.

In addition, in the 2016 NSPS OOOOa Rule, EPA recognized that promulgation of NSPS for methane emissions under

[155] Sen. Heinrich stated that he made this statement on behalf of ''[Majority [l]eader Chuck Schumer, Chairman Tom Carper of the Committee on Environment and Public Works, Senator Angus King, Senator Edward Markey and [himself],'' who he described as ''leading supporters and sponsors of S.J. Res. 14. . . .'' Senate Statement at S. 2282. Thus, the Senate Statement should be considered an authoritative piece of the legislative history. It should be noted that the Joint Resolution was referred to the Senate Committee on Environment and Public Works and discharged from the committee by petition pursuant to 5 U.S.C. 802(c), *https://www.congress.gov/bill/117th-congress/senate-joint-resolution/14/all-actions.* As a result, the resolution was not accompanied by a report from the Senate committee.

section 111(b)(1)(B) triggered the requirement that EPA promulgate EG to require States to regulate methane emissions from existing sources under section 111(d)(1), and described the steps it was taking to lay the groundwork for that regulation. 81 FR at 35831.

2. 2020 Policy Rule

The 2020 Policy Rule rescinded key elements of the 2016 NSPS OOOOa rule based on different factual assertions and statutory interpretations than in the 2016 Rule. Specifically, the 2020 Policy Rule stated that it ''contains two main actions,'' 85 FR 57019, September 14, 2020 which it identified as follows: ''First, the EPA is finalizing a determination that the source category includes only the production and processing segments of the industry and is rescinding the standards applicable to the transmission and storage segment of the industry. . . .'' *Id.* The rule justified this first action in part on the grounds that ''the processes and operations found in the transmission and storage segment are distinct from those found in the production and processing segments,'' because ''the purposes of the operations are different'' and because ''the natural gas that enters the transmission and storage segment has different composition and characteristics than the natural gas that enters the production and processing segments.'' *Id.* at 57028. ''Second, the EPA is separately rescinding the methane requirements of the NSPS applicable to sources in the production and processing segments.'' *Id.* EPA justified the rescission of the methane NSPS on two grounds. One was the EPA's ''conclu[sion] that those methane requirements are redundant with the existing NSPS for VOC and, thus, establish no additional health protections.'' *Id.* at 57019. The second was a statutory interpretation: the EPA rejected the rational basis interpretation of the 2016 Rule, and stated that instead, ''[t]he EPA interprets [the relevant provisions in CAA section 111] . . . to require, or at least to authorize the Administrator to require, a pollutant-specific SCF as a predicate for promulgating a standard of performance for that air pollutant.'' Id. at 57035. The rule went on to ''determine that the SCF for methane that the EPA made in the alternative in the 2016 [NSPS OOOOa] Rule was invalid and did not meet this statutory standard,'' for two reasons: (i) ''[t]he EPA made that finding on the basis of methane emissions from the production, processing, and transmission and storage segments, instead of just the production and processing segments''; and (ii) ''the EPA failed to support that finding with either established criteria or some type of reasonably explained and intelligible standard or threshold for determining when an air pollutant contributes significantly to dangerous air pollution.'' *Id.* at 57019. The rule recognized that ''by rescinding the applicability of the NSPS . . . to methane emissions for [oil and gas] sources . . . existing sources . . . will not be subject to regulation under CAA section 111(d).'' *Id.* at 57040.

3. CRA Resolution Disapproving the 2020 Policy Rule and Reinstating the 2016 NSPS OOOOa Rule

On June 30, 2021, the President signed into law a joint resolution adopted by Congress under the CRA disapproving the 2020 Policy Rule. By the terms of the CRA, this disapproval means that the 2020 Policy Rule is ''treated as though [it] had never taken effect.'' 5 U.S.C. 801(f). As a result, upon the disapproval, by operation of law, the 2016 NSPS OOOOa rule was reinstated, including the inclusion of the transmission and storage segment in the source category, the VOC NSPS for sources in that segment, and the methane NSPS for sources across the source category. And with the reinstatement of the methane NSPS, the EPA's obligation to issue EG to require States to regulate existing sources for methane emissions was reinstated as well. Moreover, the CRA bars an agency from promulgating ''a new rule that is substantially the same as'' a disapproved rule. 5 U.S.C. 801(b)(2).

The accompanying legislative history, specifically a House Committee report (H.R. Rep. 117–64) and a statement on the Senate floor by the sponsors of the CRA resolution (Senate Statement at S2282–83), provides additional specificity regarding Congress's intent in disapproving 2020 Policy Rule and reinstating the 2016 Rule with regard to the scope of the source category and the regulation of methane.

a. Regulation of Transmission and Storage Sources

The House Report rejected the 2020 Policy Rule's removal of the transmission and storage segment from the Crude Oil and Natural Gas Source Category, and its rescission of the VOC and methane NSPS promulgated in the 2012 NSPS OOOO and 2016 NSPS OOOOa rules for transmission and storage sources. House Report at 7; 85 FR 57029, September 14, 2020 (2020 Policy Rule). The Report recognized that in authorizing the EPA to list for regulation ''categories of sources'' under section 111(b)(1)(A) of the CAA, Congress ''provided the EPA with wide latitude to determine the scope of a source category . . . and to expand the scope of an already-listed source category if the agency later determines that it is reasonable to do so.'' House Report at 7. The Report stated that in the 2016 NSPS OOOOa, ''EPA correctly determined that the equipment and operations at production, processing, and transmission and storage facilities are a sequence of functions that are interrelated and necessary for the overall purpose of extracting, processing, and transporting natural gas for distribution.'' *Id.;* see 81 FR 35832, June 3, 2016 (2016 Rule). The Report added that the 2016 NSPS OOOOa also ''correctly determined that the types of equipment used and the emissions profile of the natural gas in the transmission and storage segments do not so distinctly differ from the types of equipment used and the emissions profile of the natural gas in the production and processing segments as to require that the EPA create a separate source category listing.'' House Report at 7; see 81 FR 35832, June 3, 2016. The Report went on to reject the 2020 Policy Rule's basis for excluding the transmission and storage segment, finding that the functions of the various segments in the Crude Oil and Natural Gas sector are all ''interrelated and necessary for the overall purpose'' of the industry, House Report at 7, and that EPA correctly determined in 2016 that the source types and emissions found in the transmission and storage segment are sufficiently similar to production and processing as to justify regulating these segments in a single source category. *Id.*

The Senate Statement was also explicit that the 2020 Policy Rule erred in rescinding NSPS for sources in the transmission and storage segment:

> [T]he resolution clarifies our intent that EPA should regulate methane and other pollution emissions from all oil and gas sources, including production, processing, transmission, and storage segments under the authority of section 111 of the CAA. In addition, we intend that section 111 . . . obligates and provides EPA with the legal authority to regulate existing sources of methane emissions in all of these segments.

Senate Statement at S2283 (paragraphing revised).

b. Regulation of Methane—Redundancy

The House Report and Senate Statement made clear Congress's view that in light of the large amount of methane emissions from oil and gas sources and their impact on global climate, the EPA must regulate those

emissions under section 111. House Report at 5; Senate Statement at S2283. Both pieces of legislative history specifically rejected the 2020 Policy Rule's rescission of the methane NSPS. House Report at 7; Senate Statement at S2283. Moreover, the legislative history specifically rejected the statutory interpretations of section 111 that formed the bases of EPA's 2020 rationales for rescinding the methane NSPS. House Report at 7–10; see Senate Statement at S2283; see 85 FR 57033, 57035–38 (September 14, 2020).

The House Report began by recognizing the critical importance of regulating methane emissions from oil and gas sources, emphasizing both the potency of methane in driving global warming, and the massive amounts of methane emitted each year by the oil and gas industry. House Report at 3–4. The House Report was clear that the amount of these emissions and their impact compelled regulatory action. *Id.* at 5. The Senate Statement was equally clear:

> [M]ethane is a leading contributing cause of climate change. It is 28 to 36 times more powerful than carbon dioxide in raising the Earth's surface temperature when measured over a 100–year time scale and about 84 times more powerful when measured over a 20–year timeframe.
>
> Industrial sources emit GHG in great quantities, and methane emissions from all segments of the Oil and Gas Industry are especially significant in their contribution to overall emissions levels and surface temperature rise. . . .
>
> In fact, with the congressional adoption of this resolution, we encourage EPA to strengthen the standards we reinstate and aggressively regulate methane and other pollution emissions from new, modified, and existing sources throughout the production, processing, transmission, and storage segments of the Oil and Gas Industry under section 111 of the Clean Air Act.
>
> The welfare of our planet and of our communities depend on it.

Senate Statement at S2283.

Turning to the 2020 Policy Rule, the House Report rejected the rule's position that the methane NSPS were redundant to the VOC NSPS, and therefore unnecessary. House Report at 7. The House Report rejected the 2020 Policy Rule's ''redundancy'' rationale, explaining that in the 2016 NSPS OOOOa, the EPA had consciously ''formulated [the two sets of NSPS so as] to impose the same requirements for the same types of equipment,'' and that the co-extensive nature of the NSPS mean that ''sources could comply with them in an efficient manner,'' not that the NSPS were redundant. *Id.* The House report further rejected the 2020 Policy Rule's assertion that it need not take into account the implications of regulating methane for existing sources, calling it a ''fundamental misinterpretation of section 111, and the critical importance of section 111(d) in Congress [*sic:* Congress's] scheme.'' House Report at 8 & n. 27 (The EPA's 2020 ''misinterpretation . . . was glaring and enormously consequential'' because it precluded regulation of methane from existing sources). The House Report emphasized that ''existing sources emit the vast majority of methane in the oil and gas sector,'' *id.* and pointed out that while the 2016 NSPS ''covered roughly 60,000 wells constructed since 2015[, t]here are more than 800,000 existing wells in operation. . . .''*Id.* n.28.

The Senate Statement also made clear that the resolution of disapproval ''reaffirms that the CAA requires EPA to act to protect Americans from sources of . . . methane,'' ''reject[s] the [2020 Policy Rule's] misguided legal interpretations,'' and ''clarifies our intent that EPA should regulate methane . . . from all oil and gas sources. . . .'' Senate Statement at 2283.

c. Regulation of Methane—Significant Contribution Finding

The legislative history was explicit that, contrary to the EPA's statutory interpretation in the 2020 Policy Rule, section 111 of the CAA, by its plain language, does not require, or authorize the EPA to require, as a prerequisite for promulgating NSPS for a particular air pollutant from a listed source category, a separate finding by the EPA that emissions of the pollutant from the source category contribute significantly to dangerous air pollution. House Report at 9–10; Senate Statement at S2283. The House Report rejected this interpretation. It made clear that instead, consistent with the EPA's statements in the 2016 NSPS OOOOa and the plain language of the CAA, section 111 requires that the agency must make a SCF only at ''the first step of the process, the listing of the source category,'' and further requires that this finding ''must apply to the impact of the 'category of sources' on 'air pollution' '' as opposed to individual pollutants. House Report at 9. The House Report went on to explain that this provision ''does not require the EPA to make a SCF for individual air pollutants emitted from the source category, nor does it even mention individual air pollutants,'' *id.* at 9. The House Report went on to explain in some detail the meaning that the EPA should give to section 111, which, consistent with the 2016 Rule, is that section 111 authorizes the agency to promulgate NSPS for particular pollutants as long as it has a rational basis for doing so. House Report at 8–9. The report explained that after the EPA lists a source category for regulation under section 111(b)(1)(A), it is required to determine for which pollutants to promulgate NSPS, and this determination is subject to CAA section 307(d)(9)(A) (''In the case of review of any [EPA] action . . . to which [section 307(d)] applies, the court may reverse any such action found to be arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law'').[156] The Report further noted that the U.S. Supreme Court affirmed this interpretation in *American Electric Power Co. Inc.* v. *Connecticut,* 564 U.S. 410, 427 (2011) (*American Electric Power*) (''EPA may not decline to regulate carbon-dioxide emissions from powerplants if refusal to act would be 'arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law'' (citing section 307(d)(9)(A)). The Report went on to note that the 2016 NSPS OOOOa had stated that the EPA was authorized to promulgate a NSPS for a particular pollutant if it had a ''rational basis'' for doing so, and the Report emphasized that this ''rational basis'' standard is ''fully consistent with'' the arbitrary and capricious standard under section 307(d)(9)(A) of the CAA. House Report at 9.[157]

The House Report further explained that, in contrast, the 2020 Policy Rule's statutory interpretation of section 111 to require a pollutant-specific SCF as a predicate for promulgating NSPS was foreclosed by ''the plain language of'' section 111—noting that this interpretation ignored the distinction between the text of section 111 and that of other CAA provisions which do explicitly require a pollutant-specific cause-or-contribution finding. *Id.* at 10. Moreover, the Report added, ''[g]iven that the statute is not ambiguous, the EPA cannot interpret section 111 to authorize the EPA to exercise discretion to require . . . a pollutant-specific SCF as a predicate for promulgating a [NSPS] for the pollutant.'' *Id.* at 10. The Report went on to note several other supports for its statutory interpretation, including the legislative history of section 111. *Id.* at 10–11.

The Senate Statement took the same approach, stating: ''we do not intend that section 111 of [the] CAA requires EPA to make a pollutant-specific

[156] Section 307(d) applies to the promulgation of NSPS, under section 307(d)(1)(C).

[157] The House Report dismissed the 2020 Policy Rule's criticism of the rational basis test as unduly vague by noting that a court could enforce it. House Report at 11.

significant contribution finding before regulating emissions of a new pollutant from a listed source category. . . .'' Senate Statement at S2283.[158]

The House Report also expressly disapproved of the 2020 Policy Rule's interpretation of section 111 to require that the SCF must be based on some ''identif[ied] standard or established set of criteria,'' and not the facts-and-circumstances approach that EPA has used in making that finding for the source category. House Report at 10–11; *see* 2020 Policy Rule at 57038. The Report stated, ''[i]t is fully appropriate for EPA to exercise its discretion to employ a facts-and-circumstances approach, particularly in light of the wide range of source categories and the air pollutants they emit that EPA must regulate under section 111.'' House Report at 11.

Finally, in reinstating the methane regulations, the legislative history for the CRA resolution clearly expressed the intent that the EPA proceed with regulation of existing sources. The House Report was explicit in this regard, stating that ''[p]assage of the resolution of disapproval indicates Congress' support and desire to immediately reinstate . . . EPA's statutory obligation to regulate existing oil and natural gas sources under [CAA] section 111(d).'' House Report at 3; see *id.* at 11–12. The report added that upon enactment of the resolution of disapproval, ''the Committee strongly encourages the EPA to take swift action to . . . fulfill its statutory obligation to issue existing source guidelines under [CAA] section 111(d).'' *Id.* The Senate Statement was substantially similar. Senate Statement at S2283 (''By adopting this resolution of disapproval, it is our view that Congress reaffirms that the CAA requires EPA to act to protect Americans from sources of climate pollution like methane, which endangers the public's health and welfare. . . . [W]e intend that [CAA] section 111 . . . obligates and provides EPA with the legal authority to regulate existing sources of methane emissions in [the Crude Oil and Natural Gas source category].'').

[158] Both the House Report and the Senate Statement recognized that EPA could, if it chose to, make a finding that a particular pollutant contributes significantly to dangerous air pollution, in order, for example, to inform the public about the risks of a pollutant. House Report at 10, Senate Statement at S2283. However, the House Report made clear that ''it is the rational basis determination as to the risk a pollutant poses to endangerment of human health or welfare [and not any such SCF] that remains the statutory basis for the EPA's action.'' House Report at 10.

B. Effect of Congress's Disapproval of the 2020 Policy Rule

Under the CRA, the disapproved 2020 Policy Rule is ''treated as though [it] had never taken effect.'' 5 U.S.C. 801(f). As a result, the preceding regulation, the 2016 NSPS OOOOa rule, was automatically reinstated, and treated as though it had never been revised by the 2020 Policy Rule. Moreover, the CRA bars EPA from promulgating ''a new rule that is substantially the same as'' a disapproved rule. 5 U.S.C. 801(b)(2), for example, a rule that deregulates methane emissions from the production and processing sectors or deregulates the transmission and storage sector entirely.

The legislative history of the CRA gives further content to Congress's disapproval and the bar on substantially similar rulemaking. The legislative history rejected the EPA's statutory interpretations of section 111 in the 2020 Policy Rule and endorsed the legal interpretations contained in the 2016 NSPS OOOOa rule. Specifically, Congress expressed its intent that the transmission and storage segment be included in the source category, that sources in that segment remain subject to NSPS, and that all oil and gas sources be subject to NSPS for methane emissions.[159]

The EPA is now proceeding to propose additional requirements to reduce emissions from oil and gas sources, consistent with the statutory factors the EPA is required to consider under section 111 and with section 111's overarching purpose of protecting against pollution that endangers health and welfare. While the reinstatement of the 2016 Rule through the CRA joint resolution of disapproval provides the predicate for this action, the EPA notes that, for the reasons discussed next, the EPA would reject the positions concerning legal interpretations taken in the 2020 Policy Rule and reaffirm the positions the Agency took in the 2016 Rule even absent the CRA resolution. The EPA provides this information for the purposes of informing the public and is not re-opening these positions for comment.

C. Affirming the Legal Interpretations in the 2016 NSPS OOOOa Rule

The Agency has reviewed all of the information and analyses in the 2016 NSPS OOOOa and 2020 Policy Rule, and fully reaffirms the positions it took in the 2016 Rule and rejects the positions taken in the 2020 Policy Rule.[160] For this rulemaking, the EPA has reviewed its prior actions, along with newly available information, including recent information concerning the dangers posed by climate change and the impact of methane emissions, as described in section III above. Based on this review, the EPA affirms the statutory interpretations underlying the 2016 Rule and rejects the different interpretations informing the congressionally voided 2020 Policy Rule. This section explains the EPA's views. These views are confirmed by Congress's reasoning in the legislative history of the CRA resolution and so, for convenience, this section occasionally refers to that legislative history.

In particular, the EPA reaffirms that the Crude Oil and Natural Gas Source Category appropriately includes the transmission and storage segment, along with the production and processing segments. The EPA has broad discretion in determining the scope of the source category, and the 2016 Rule correctly identified the most important aspect of the industry, which is the interrelatedness of the segments and their common purpose in completing the multi-step process to prepare natural gas for marketing. 81 FR 35832, June 3, 2016. The 2020 Policy Rule's objection that the chemical composition of natural gas changes as it moves from the production and processing segments to the transmission and storage segment, 85 FR 57028, September 14, 2020, misses the mark because in every segment methane predominates and the refining of natural gas in the processing segment, which is what changes its chemical composition, is appropriately viewed simply as one of the steps in the marketing of the gas. Further, while it is true that some of the equipment in each segment differs from the equipment in the other segments, as the 2020 Policy Rule pointed out, 85 FR 57029 (September 14, 2020), that too simply results from the fact that the segments represent different steps in the process of preparing natural gas for marketing. The more salient fact is that most of the polluting equipment, such as storage

[159] See generally ''Federal-State Unemployment Compensation Program; Establishing Appropriate Occupations for Drug Testing of Unemployment Compensation Applicants Under the Middle-Class Tax Relief and Job Creation Act of 2012: Final Rule,'' 84 FR 53037, 53083 (Oct. 4, 2019) (citing legislative history of CRA resolution disapproving prior rule in explaining scope of new rule).

[160] Under *F.C.C.* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009), an agency may revise its policy, but must demonstrate that the new policy is permissible under the statute and is supported by good reasons, taking into account the record of the previous rule. To the extent that this standard applies in this action—where Congress has disapproved the 2020 Policy Rule—the EPA believes the explanations provided here satisfy the standard.

vessels, pneumatic pumps, and compressors, are found throughout the segments and emit the same pollutants that can be controlled by the same techniques and technologies, 81 FR 35832 (June 3, 2016), underscoring the interrelated functionality of the segments and the appropriateness of regulating them together as part of a single source category. The scope of the source category as defined in 2016, and proposed to be affirmed in this rule, is well within the reasonable bounds of the EPA's past practice in defining source categories, which sometimes even contain sources that are located in multiple distinct industries. *See* 40 CFR part 60, subpart Db (industrial-commercial-institutional steam generating units), 40 CFR part 60, subpart IIII (stationary compression ignition internal combustion engines). In this regard, the House Report correctly noted that ''even the presence of large distinctions in equipment type and emissions profile across two segments would not necessarily preclude EPA from regulating those segments as a single source category, so long as the EPA could identify some meaningful relationship between them,'' House Report at 7, as the EPA did in the 2016 Rule. Thus, the 2020 Policy Rule failed to articulate appropriate reasons to change the scope of the source category from what the EPA determined in the 2016 Rule. Having properly identified the scope of the source category as including the transmission and storage segment in the 2016 Rule, the EPA lawfully promulgated NSPS for sources in that segment.

The EPA also affirms that the 2016 Rule established an appropriate basis for promulgating methane NSPS from oil and gas sources, and that the 2020 Policy Rule erred on all grounds in rescinding the methane NSPS. The importance of taking action at this time, in accordance with the requirements of CAA section 111, to reduce the enormous amount of methane emissions from oil and gas sources, in light of the impacts on the climate of this pollution, cannot be overstated. As stated in section I, the Oil and Natural Gas Industry is the largest industrial emitter of methane in the U.S. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. According to the IPCC, strong, rapid, and sustained methane reductions are critical to reducing near-term disruption of the climate system and a vital complement to CO_2 reductions critical in limiting the long-term extent of climate change and its destructive impacts.[161] The EPA previously determined, in the 2016 NSPS OOOOa rule, both that it had a rational basis to regulate methane emissions from the source category, and, in the alternative, that methane emissions from the Crude Oil and Natural Gas Source Category, contribute significantly to dangerous air pollution. 81 FR 35842–43, (June 3, 2016). The EPA is not reopening those determinations for comment in the present rulemaking.

Contrary to the statements in the 2020 Policy Rule, the methane NSPS promulgated in the 2016 Rule cannot be said to be redundant with the VOC NSPS and therefore unnecessary. The large contribution of methane emissions from the source category to dangerous air pollution driving the grave and growing threat of climate change means that, in the agency's judgment, it would be highly irresponsible and also arbitrary and capricious under CAA section 307(d)(9)(A) for the EPA to decline to promulgate NSPS for methane emissions from the source category. *See American Electric Power,* 564 U.S. at 426–27. The fact that the EPA designed the methane NSPS so that sources could comply with them efficiently, through the same actions that the sources needed to take to comply with the VOC NSPS, did not thereby create redundancy. Further, the fact that methane NSPS but not the VOC NSPS trigger the regulatory requirements for existing sources makes clear that the two sets of requirements are not redundant. Indeed, if EPA had only regulated VOCs, it would only have been authorized to regulate new and modified sources, which comprise a small subset of polluting sources. By contrast, because the 2016 Rule also regulated methane, EPA was authorized and obligated to regulate hundreds of thousands of additional ''existing'' sources that comprise the vast majority of polluting sources. Accordingly, methane regulation was not ''redundant'' of VOC regulation. The 2020 Policy Rule's contrary position was based on a misinterpretation of CAA section 111 which overlooked that the provision integrates requirements for new and existing sources. See *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433 n.48 (D.C. Cir. 1980) (CAA section 111(b)(1)(A) listing of a source category is based on emissions from new and existing sources).

The EPA also reaffirms the 2016 Rule's statutory interpretation that the EPA is authorized to promulgate a NSPS for an air pollutant under CAA section 111(b)(1)(B) in a situation in which the EPA has previously determined that the source category causes or contributes significantly to dangerous air pollution and where the EPA has a rational basis for regulating the particular air pollutant in question that is emitted by the source category. 81 FR 35842 (June 3, 2016). The 2016 Rule noted the precedent in prior agency actions for the position that—following the listing of a source category—the EPA need provide only a rational basis for its exercise of discretion for which pollutants to regulate under section 111(b)(1)(B). *See id.* (citing *National Lime Assoc.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (court discussed, but did not review, the EPA's reasons for not promulgating standards for NO_X, SO_2, and CO from lime plants). In addition, the Supreme Court in *American Electric Power* provided support for the rational basis statutory interpretation. 564 U.S. at 426–27 (''EPA [could] decline to regulate carbon-dioxide emissions altogether at the conclusion of its . . . [CAA section 111] rulemaking,'' and such a decision ''would not escape judicial review,'' under the ''arbitrary and capricious'' standard of section 307(d)(9)(A)). As the House Report noted, the EPA's rational basis interpretation ''is fully consistent with the provision[s] of section 111 and the section 307(d)(9) 'arbitrary and capricious' standard.'' House Report at 9.

The 2020 Policy Rule correctly noted that the CAA section 111(b)(1)(B) requirement that the EPA ''shall promulgate . . . standards [of performance]'' for air pollutants, coupled with the CAA section 111(a)(1) definition for ''standard of performance'' as, in relevant part, a ''standard for emissions of air pollutants,'' does not by its terms require that EPA promulgate NSPS for every air pollutant from the source category. But the rule erred in seeking to graft the CAA section 111(b)(1)(A) requirement for a SCF into CAA section 111(b)(1)(B). The language of CAA section 111(b)(1)(A) is clear: It requires the EPA Administrator to ''include a *category of sources* in [the list for regulation] if in his judgment it causes, or contributes to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' (Emphasis added.) Congress thus specified that the required SCF is made

[161] See preamble section III for further discussion on the Crude Oil and Natural Gas Emissions and Climate Change, including discussion of the GHGs, VOCs and SO_2 Emissions on Public Health and Welfare.

on a category basis, not a pollutant-specific basis, and that once that finding is made (as it was for the Crude Oil and Natural Gas source category in 1979), the EPA may establish standards for pollutants emitted by the source category. In determining for which air pollutants to promulgate standards of performance, the EPA must act rationally, which, as noted above, essentially must ensure that the action does not fail the ''arbitrary and capricious'' standard under CAA section 307(d)(9)(A). The 2020 Policy Rule's objections to the rational basis standard on grounds that is ''vague and not guided by any statutory criteria,'' 85 FR 57034 (September 14, 2020), is incorrect. In making a rational basis determination, the EPA has considered the amount of the air pollutant emitted by the source category, both in absolute terms and by drawing comparisons, as well as the availability of control technologies. *See National Lime Assoc.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (discussing EPA's reasons for not promulgating standards for NO_X, SO_2 and CO from lime plants); 80 FR 64510, 64530 (October 23, 2015) (rational basis determination for GHGs from fossil fuel-fired electricity generating power plants); 73 FR 35838, 35859–60 (June 24, 2008) (providing reasons why the EPA was not promulgating GHG standards for petroleum refineries). Courts routinely review rules under the ''arbitrary and capricious'' standard, as noted in the House Report, at 11.

When the EPA is required to make an endangerment finding, the EPA also affirms that that finding should be made in consideration of the particular facts and circumstances, not a predetermined threshold. Accordingly, the EPA rejects the 2020 Policy Rule's position to the contrary. Section 111(b)(1)(A) of the CAA does not require that the SCF for the source category be based on ''established criteria'' or ''standard or threshold.'' *See Coal. for Responsible Regulation, Inc.* v. *EPA,* 684 F.3d 102, 122–23 (D.C. Cir. 2012) (''the inquiry [into whether an air pollutant endangers] necessarily entails a case-by-case, sliding-scale approach. . . . EPA need not establish a minimum threshold of risk or harm before determining whether an air pollutant endangers''). During the 50 years that it has made listing decisions, the EPA has always relied on the individual facts and circumstances. *See Alaska Dep't of Envtl. Conservation,* 540 U.S. 461, 487 (2004) (explaining, in a case under the CAA, ''[w]e normally accord particular deference to an agency interpretation of longstanding duration'' (internal quotation marks omitted) (citing *Barnhart* v. *Walton,* 535 U.S. 212, 220 (2002)). This approach is appropriate because Congress intended that CAA section 111 apply to a wide range of source categories and pollutants, from wood heaters to emergency backup engines to petroleum refineries. In that context, it reasonable to interpret section 111 to allow EPA the discretion to determine how best to assess significant contribution and endangerment based on the individual circumstances of each source category. On this point, as well, the EPA is in full agreement with the statements in the House Report. House Report at 9–10.

Finally, under CAA section 111(d)(1), once the EPA promulgates NSPS for certain air pollutants, including GHGs, the EPA is required to promulgate regulations, which the EPA terms EG, 40 CFR 60.22a, that in turn require States to promulgate standards of performance for existing sources of those air pollutants. The EPA agrees with the House Report and Senate statement that it is imperative to regulate methane emissions from the existing oil and gas sources that comprise the vast majority of polluting sources expeditiously under the authority of CAA section 111(d) and is proceeding with the process to do so in this rulemaking by publishing proposed EG. See section III.B.2. In 2019, the GHGI estimates for oil and natural gas production, and natural gas processing and transmission and storage segments that methane emissions equate to 182 MMT CO_2 Eq.[162] In the U.S. the EPA has identified over 15,000 oil and gas owners and operators, around 1 million producing onshore oil and gas wells, about 5,000 gathering and boosting facilities, over 650 natural gas processing facilities, and about 1,400 transmission compression facilities.

Some stakeholders have raised issues concerning the scope of pollutants subject to CAA section 111(d) by arguing that the exclusion in CAA section 111(d) for HAP covers not only those pollutants listed for regulation under CAA section 112, but also precludes the EPA from regulating a source category under CAA section 111(d) for *any* pollutant if that source category has been regulated under CAA section 112. The EPA agrees with its longstanding legal interpretation spanning multiple Administrations that the 111(d) exclusion does not preclude the agency from regulating a non-HAP pollutant from a source category under section 111(d) even if that source category is regulated under section 112. See *American Lung Ass'n* v. *EPA,* 980 F.3d 914, 980 (D.C. Cir. 2019) (referring to ''EPA's three-decade-old . . . reading of the statutory amendments''), *petition for cert. pending* No. 20–1530 (filed April 29, 2021); 70 FR 15994, 16029 (March 29, 2005) (Clean Air Mercury Rule); 80 FR 64662, 64710 (Oct. 23, 2015) (Clean Power Plan); 84 FR 32520 (July 8, 2019) (Affordable Clean Energy Rule). The House Report agreed with this interpretation, noting that the contrary position is flawed because it ignores the overall statutory structure that Congress created in the CAA and would create regulatory gaps in which the EPA would not be able to regulate existing sources for some pollutants (such as methane) under CAA section 111(d) if those sources (but not pollutants) were already regulated for different pollutants under CAA section 112. House Report at 11–12. Moreover, the D.C. Circuit recently considered this precise issue and held that the EPA may both regulate a source category for HAP under CAA section 112 and regulate that same source category for different pollutants under CAA section 111(d). *Am. Lung Assoc.,* 985 F.3d at 977–988. Accordingly, both Congress and the court have come to the same conclusion after reviewing the statutory language, a conclusion that is aligned with the EPA's longstanding position. We therefore proceed in the proposal to propose EGs for existing sources in the oil and gas source category.

IX. Overview of Control and Control Costs

A. Control of Methane and VOC Emissions in the Crude Oil and Natural Gas Source Category—Overview

As described in this action, the EPA reviewed the standards in the 2016 NSPS OOOOa pursuant to CAA section 111(b)(1)(B). Based on this review, the EPA is proposing revisions to the standards for a number of affected facilities to reflect the updated BSER for those affected facilities. Where our analyses show that the BSER for an

[162] The 100-year GWP value of 25 for methane indicates that one ton of methane has approximately as much climate impact over a 100-year period as 25 tons of CO_2. The most recent IPCC AR6 assessment has estimated a slightly larger 100-year GWP of methane of almost 30 (specifically, either 27.2 or 29.8 depending on whether the value includes the CO_2 produced by the oxidation of methane in the atmosphere). As mentioned earlier, because methane has a shorter lifetime than CO_2, the emissions of a ton of methane will have more impact earlier in the 100-year timespan and less impact later in the 100-year timespan relative to the emissions of a 100-year GWP-equivalent quantity of CO_2. See preamble section III for further discussion on the Crude Oil and Natural Gas Emissions and Climate Change, including discussion of the GHGs, VOCs and SO_2 Emissions on Public Health and Welfare.

affected facility remains the same, the EPA is proposing to retain the current standard for that affected facility. In addition to the actions on the standards in the 2016 NSPS OOOOa described in this section, the EPA is proposing standards for GHGs (in the form of limitation on methane) and VOCs for a number of new sources that are currently unregulated. The proposed NSPS OOOOb would apply to new, modified, and reconstructed emission sources across the Crude Oil and Natural Gas source category for which construction, reconstruction, or modification is commenced after November 15, 2021.

Further, pursuant to CAA section 111(d), the EPA is proposing EG, which include presumptive standards for GHGs (in the form of limitations on methane) (designated pollutant), for certain existing emission sources across the Crude Oil and Natural Gas source category in the proposed EG OOOOc. While the proposed requirements in NSPS OOOOb would apply directly to new sources, the proposed requirements in EG OOOOc are for States to use in the development of plans that establish standards of performance that will apply to existing sources (designated facilities).

B. How does EPA evaluate control costs in this action?

Section 111 of the CAA requires that the EPA consider a number of factors, including cost, in determining ''the best system of emission reduction . . . adequately demonstrated.'' CAA section 111(a)(1). The D.C. Circuit has long recognized that ''[CAA] section 111 does not set forth the weight that [ ] should [be] assigned to each of these factors;'' therefore, ''[the court has] granted the agency a great degree of discretion in balancing them.'' *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (''*Lignite Energy Council*''). In *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973) (''*Essex Chemical*''), the court noted that ''it is not unlikely that the industry and the EPA will disagree on the economic costs of various control techniques'' and that it ''has no desire or special ability to settle such a dispute.'' *Id.* at 437. Rather, the court focused its review on ''whether the standards as set are the result of reasoned decision-making.'' *Id.* at 434. A standard that ''is the result of the exercise of reasoned discretion by the Administrator [ ] cannot be upset by this Court.'' *Id.* at 437.

As noted, CAA section 111 requires that the EPA consider cost in determining such system (*i.e.,* ''BSER''), but it does not prescribe any criteria for such consideration. The courts have recognized that the EPA has ''considerable discretion under [CAA] section 111,'' *Lignite Energy Council,* 198 F.3d at 933, on how it considers cost under CAA section 111(a)(1). For example, in *Essex Chemical,* the D.C. Circuit stated that to be ''adequately demonstrated,'' the system must be ''reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' 486 F.2d at 433. The court has reiterated this limit in subsequent case law, including *Lignite Energy Council,* in which it stated: ''EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.'' 198 F.3d at 933. In *Portland Cement Association* v. *Train,* the court elaborated by explaining that the inquiry is whether the costs of the standard are ''greater than the industry could bear and survive.'' [163] 513 F.2d 506, 508 (D.C. Cir. 1975). In *Sierra Club* v. *Costle,* the court provided a substantially similar formulation of the cost factor: ''EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.'' 657 F.2d 298, 343 (D.C. Cir. 1981). We believe that these various formulations of the cost factor—''exorbitant,'' ''greater than the industry could bear and survive,'' ''excessive,'' and ''unreasonable''—are synonymous; the D.C. Circuit has made no attempt to distinguish among them. For convenience, in this rulemaking, we will use the term ''reasonable'' to describe that our evaluation of costs is well within the boundaries established by this case law.

In evaluating whether the cost of a control is reasonable, the EPA considers various costs associated with such control, including capital costs and operating costs, and the emission reductions that the control can achieve. As discussed further below, the agency considers these costs in the context of the industry's overall capital expenditures and revenues. Cost-effectiveness analysis is also a useful metric, and a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost-effectiveness analysis also allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost-effectiveness is a measure of the outcomes produced by resources spent. In the context of air pollution control options, cost-effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually. A cost-effectiveness analysis is not intended to constitute or approximate a benefit-cost analysis in which monetized benefits are compared to costs, but rather provides a metric to compare the relative cost and emissions impacts of various control options.

The estimation and interpretation of cost-effectiveness values is relatively straightforward when an abatement measure is implemented for the purpose of controlling a single pollutant, such as for the controls included as presumptive standards in the proposed EG OOOOc to address methane emissions from existing sources in the Crude Oil and Natural Gas source category. In other circumstances, air pollution reduction programs require reductions in emissions of multiple pollutants, as with the NSPS for the Crude Oil and Natural Gas source category, which regulates both GHG and VOC. In such cases, multipollutant controls (controls that achieve reductions of both pollutants through the same techniques and technologies) may be employed, and consequently, there is a need for determining cost-effectiveness for a control option across multiple pollutants (or classes of multiple pollutants).

During the rulemaking for NSPS OOOOa, we evaluated a number of approaches for considering the cost-effectiveness of the available multipollutant controls for reducing both methane and VOC emissions. See 80 FR 56593, 56616 (September 18, 2015). In that rulemaking, we used two approaches for considering the cost-effectiveness of control options that reduce both VOC and methane emissions; we are proposing to use these same two cost-effectiveness approaches, along with other factors discussed further below, in considering the cost of requiring control for the proposed NSPS OOOOb. One approach, which we refer to as the ''single pollutant cost-effectiveness approach,'' assigns all costs to the emission reduction of one pollutant and zero to all other concurrent reductions. If the cost is reasonable for reducing any of the

[163] The 1970 Senate Committee Report on the Clean Air Act stated: ''The implicit consideration of economic factors in determining whether technology is 'available' should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.'' S. Comm. Rep. No. 91–1196 at 16.

targeted pollutants alone, the cost of such control is clearly reasonable for the concurrent emission reduction of all the other regulated pollutants because they are being reduced at no additional cost. While this approach assigns all costs to only a portion of the emission reduction and thus may overstate the cost for that assigned portion, it does not overstate the overall cost. Instead, it acknowledges that the reductions of the other regulated pollutant are intended as opposed to incidental. This approach is simple and straightforward in application: If the multipollutant control is cost effective for reducing emissions of either of the targeted pollutants, it is clearly cost effective for reducing all other targeted emissions that are being achieved simultaneously.

A second approach, which we term for the purpose of this rulemaking a ''multipollutant cost-effectiveness approach,'' apportions the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In the case of the Crude Oil and Natural Gas source category, both methane and VOC are reduced in equal proportions, relative to their respective baselines by the multipollutant control option (*i.e.,* where control is 95 percent reduction, methane and VOC are both simultaneously reduced by 95 percent by the multipollutant control). As a result, under the multipollutant cost-effectiveness approach, half of the control costs are allocated to methane and the other half to VOC. Under this approach, control is cost effective if it is cost effective for both VOC and methane.

We believe that both the single pollutant and multipollutant cost-effectiveness approaches discussed above are appropriate for assessing the reasonableness of the multipollutant controls considered in this action for new sources. As such, in the individual BSER analyses in section XII below, if a device is cost-effective under either of these two approaches, we find it to be cost-effective. The EPA has considered similar approaches in the past when considering multiple pollutants that are controlled by a given control option.[164] The EPA recognizes, however, not all situations where multipollutant controls are applied are the same, and that other types of approaches might be appropriate in other instances.

As mentioned above, as part of its consideration of control costs in the individual BSER analyses in Section XII, the EPA evaluated cost-effectiveness using the single pollutant and multipollutant cost-effectiveness approaches. We estimated the cost-effectiveness values of the proposed control options using available information, including various studies, information submitted in previous rulemakings from the affected industry, and information provided by small businesses. The EPA provides the cost effectiveness estimates for reducing VOC and methane emissions for various control options considered in section XII. As discussed in that section, the EPA finds cost-effectiveness values up to $5,540/ton of VOC reduction to be reasonable for controls that we have identified as BSER in this proposal. These VOC values are within the range of what the EPA has historically considered to represent cost effective controls for the reduction of VOC emissions, including in the 2016 NSPS, based on the Agency's long history of regulating a wide range of industries. With respect to methane, the EPA finds the cost-effectiveness values up to $1,800/ton of methane reduction to be reasonable for controls that we have identified as BSER in this proposal. Unlike VOC, the EPA does not have a long regulatory history to draw upon in assessing the cost effectiveness of controlling methane, as the 2016 NSPS OOOOa was the first national standard for reducing methane emissions. However, as explained below, the EPA has previously determined that methane cost-effectiveness values for the controls identified as BSER for the 2016 NSPS OOOOa, which range up to $2,185/ton of methane reduction, represent reasonable costs for the industry as a whole to bear; and because the cost-effectiveness estimates for the proposed standards in this action are comparable to the cost-effectiveness values estimated for the controls that served as the basis (*i.e.,* BSER) for the standards in the 2016 NSPS OOOOa, we consider the proposed standards to also be cost effective and reasonable.

The BSER determinations from the 2016 NSPS OOOOa also support the EPA's conclusion that the cost-effectiveness values associated with the proposed standards in this action are reasonable. As mentioned above, for 2016 NSPS OOOOa, the highest estimate that the EPA considered cost effective for methane reduction was $2,185/ton, which was the estimate for converting a natural gas driven diaphragm pump to an instrument air pump at a gas processing plant. [165] [166] 80 FR 56627; see also, NSPS OOOOa Final TSD at 93, Table 6–7. The EPA estimated that the cost-effectiveness of this option, a common practice at gas processing plants, could be up to $2,185/ton of methane reduction under the single pollutant cost-effectiveness approach and $1,093/ton under the multipollutant cost effectiveness approach; the EPA found ''the control to be cost effective under either approach.'' *Id.* Accordingly, the EPA finalized requirements in the 2016 NSPS OOOOa that require zero emissions from diaphragm pumps at gas processing plants, consistent with the Agency's BSER determination.

The 2016 NSPS OOOOa also requires 95 percent methane and VOC emission reduction from wet-seal centrifugal compressors. The BSER for this standard was capturing and routing the emissions to a control combustion device, a widely used control in the oil and gas sector for reducing emissions from storage vessels and pumps, in addition to centrifugal compressors. 80 FR 56620. The EPA estimated cost-effectiveness values of up to $1,093/ton of methane reduction for this option. *See* NSPS OOOOa Final TSD at 114, Table 7–9. With respect to other controls identified as BSER in the 2016 NSPS OOOOa, their cost-effectiveness estimates were comparable to or well below the estimates from the 2016 NSPS OOOOa rulemaking discussed above. In light of this, and because sources have been complying with the 2016 NSPS OOOOa for years, we believe that the cost-effectiveness values for the controls

[164] See, *e.g.,* 73 FR 64079–64083 and EPA Document I.D. EPA–HQ–OAR–2004–0022–0622, EPA–HQ–OAR–2004–0022–0447, EPA–HQ–OAR–2004–0022–0448.

[165] As discussed in section X.A, the EPA incorrectly stated in the 2020 Technical Rule that $738/ton of methane reduction was the highest cost-effectiveness value that the EPA determined to be reasonable for methane reduction in the 2016 NSPS OOOOa.

[166] While in that rulemaking the EPA found quarterly monitoring of fugitive emissions at well sites not cost effective at $1,960/ton of methane reduced using the single pollutant approach (and $980 using the multi-pollutant approach), the EPA emphasized that this conclusion was not intended to ''preclude the EPA from taking a different approach in the future including requiring more frequent monitoring (*e.g.,* quarterly).'' 81 FR 35855–6 referencing *Background Technical Support Document for the New Source Performance Standards 40 CFR part 60 subpart OOOOa* (May 2016), at 49, Table 4–11 and 52, Table 4–14. Further, several states have issued regulations and industry has voluntarily taken steps to reduce emissions. This combined with greater knowledge and understanding of the industry leads us to find these values cost-effective. As discussed in this section IX.B, cost-effectiveness is one—not the only—factor in EPA's consideration of control costs. In fact, in this action, the EPA is proposing different monitoring frequencies based on well site baseline emissions, even though the EPA found quarterly monitoring to be cost effective for all well sites. Please see section XII.A for a detailed discussion on this proposal.

identified as BSER for the 2016 NSPS OOOOa, which range up to $2,185/ton of methane reduction, represent reasonable, rather than excessive, costs for the industry as a whole to bear. As shown in the individual BSER analyses in Section XII and the NSPS OOOOb and EG OOOOc TSD for this proposal, the cost-effectiveness values for the proposed standards in this action are comparable to the cost-effectiveness values for the standards in NSPS OOOOa. We, therefore, similarly consider the cost-effectiveness values for the proposed standards to be reasonable. That the proposed standards reflect the kinds of controls that many companies and sources around the country are already implementing underscore the reasonableness of these control measures.

In addition to evaluating the annual average cost-effectiveness of a control option, the EPA also considers the incremental costs associated with increasing the stringency of the standards from one level of control to another level of control that achieves more emission reductions. The incremental cost of control provides insight into how much it costs to achieve the next increment of emission reductions through application of each increasingly stringent control options, and thus is a useful tool for distinguishing among the effects of more and less stringent control options. For example, during the rulemaking for the 2012 NSPS OOOO, the EPA considered the incremental cost effectiveness of changing the originally promulgated standards for leaks at gas processing plants, which were based on NSPS subpart VV, to the more stringent NSPS subpart VVa-level program. See 76 FR 52738, 52755 (August 23, 2011). The EPA generally finds the incremental cost-effectiveness to be reasonable if it is consistent with the costs that the Agency considers reasonable in its evaluation of annual average cost-effectiveness.

As shown in the NSPS OOOOb and EG OOOOc TSD for this action, the EPA estimated control costs both with and without savings from recovered gas that would otherwise be emitted. When determining the overall costs of implementation of the control technology and the associated cost-effectiveness, the EPA reasonably takes into account any expected revenues from the sale of natural gas product that would be realized as a result of avoided emissions that result from implementation of a control. Such a sale would offset regulatory costs and so should be included to accurately assess the overall costs and the cost-effectiveness of the standard. In our analysis we consider any natural gas that is either recovered or that is not emitted as a result of a control option as being ''saved.'' We estimate that one thousand standard cubic feet (Mcf) of natural gas is valued at $3.13 per Mcf.[167] Our cost analysis then applies the monetary value of the saved natural gas as an offset to the control cost.[168] This offset applies where, in our estimation, the monetary savings of the natural gas saved can be realized by the affected facility owner or operator and not where the owner or operator does not own the gas and would not likely realize the monetary value of the natural gas saved (*e.g.,* transmission stations and storage facilities). Detailed discussions of these assumptions are presented in section 2 of the RIA associated with this action, which is in the docket.

We also completed two additional analyses to further inform our determination of whether the cost of control is reasonable, similar to compliance cost analyses we have completed for other NSPS.[169] First, we compared the capital costs that would be incurred to comply with the proposed standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the proposed standards to the level of new capital expenditures that the industry is incurring in the absence of the proposed standards. We then determined whether the capital costs appear reasonable in comparison to the industry's current level of capital spending. Second, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us to evaluate the annualized costs as a percentage of the revenues being generated by the industry.

The EPA has evaluated incremental capital costs in a manner similar to the analyses described above in prior new source performance standards, and in those prior standards, the Agency's determinations that the costs were reasonable were upheld by the courts. For example, the EPA estimated that the costs for the 1971 NSPS for coal-fired electric utility generating units were $19 million for a 600 MW plant, consisting of $3.6 million for particulate matter controls, $14.4 million for sulfur dioxide controls, and $1 million for nitrogen oxides controls, representing a total 15.8 percent increase in capital costs above the $120 million cost of the plant.[170] *See* 1972 Supplemental Statement, 37 FR 5767, 5769 (March 21, 1972). The D.C. Circuit upheld the EPA's determination that the costs associated with the final 1971 standard were reasonable, concluding that the EPA had properly taken costs into consideration. *Essex Chemical,* 486 F. 2d at 440. Similarly, in *Portland Cement Association* v. *Ruckelshaus,* the D.C. Circuit upheld the EPA's consideration of costs for a standard of performance that would increase capital costs by about 12 percent, although the rule was remanded due to an unrelated procedural issue. 486 F.2d 375, 387–88 (D.C. Cir. 1973). Reviewing the EPA's final rule after remand, the court again upheld the standards and the EPA's consideration of costs, noting that ''[t]he industry has not shown inability to adjust itself in a healthy economic fashion to the end sought by the Act as represented by the standards prescribed.'' *Portland Cement Assn.* v. *Train,* 513 F. 2d at 508.

In this action, for the capital expenditures analysis, we divide the nationwide capital expenditures projected to be spent to comply with the proposed standards by an estimate of the total sector-level new capital expenditures for a representative year to determine the percentage that the nationwide capital cost requirements under the proposal represent of the total capital expenditures by the sector. We combine the compliance-related capital costs under the proposed standards for the NSPS and for the presumptive standards in the proposed EG to analyze the potential aggregate impact of the proposal. The EAV of the projected compliance-related capital expenditures over the 2023 to 2035 period is projected to be about $510 million in 2019 dollars. We obtained new capital

[167] This value reflects the forecasted Henry Hub price for 2022 from: U.S. Energy Information Administration. Short-Term Energy Outlook. *https://www.eia.gov/outlooks/steo/archives/may21.pdf.* Release Date: May 11, 2021.

[168] While the EPA presents cost-effectiveness with and without cost savings, the BSER is determined based on the cost-effectiveness without cost savings in all cases.

[169] For example, see our compliance cost analysis in ''Regulatory Impact Analysis (RIA) for Residential Wood Heaters NSPS Revision. Final Report.'' U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. EPA–452/R–15–001, February 2015.

[170] Assuming these costs were denominated in 1971 dollars, converting the costs from 1971 to 2019 dollars using the Gross Domestic Product-Implicit Price Deflator, the costs for the 1971 NSPS for coal-fired electric utility generating units were $94 million for a 600 MW plant, consisting of $18 million for particulate matter controls, $71 million for sulfur dioxide controls, and $5 million for nitrogen oxides controls, representing a 15.8 percent increase in capital costs above the $590 million cost of the plant.

expenditure data for relevant NAICS codes for 2018 from the U.S. Census 2019 Annual Capital Expenditures Survey.[171] Estimates of new capital expenditures are available for 2019, but we chose to use 2018 because the 2019 new capital expenditure data for pipeline transportation of natural gas (NAICS 4862) are withheld to avoid disclosing data for individual enterprises, and the withholding of that NAICS causes the totals for 2019 to be lower than for 2018. According to these data, new capital expenditures for the sector in 2018 were about $155 billion in 2019 dollars. Comparing the EAV of the projected compliance-related capital expenditures under the proposal with the 2018 total sector-level new capital expenditures yields a percentage of about 0.3 percent, which is well below the percentage increase previously upheld by the courts, as discussed above.

For the comparison of compliance costs to revenues, we use the EAV of the projected compliance costs without and with projected revenues from product recovery under the proposal for the 2023 to 2035 period then divided the nationwide annualized costs by the annual revenues for the appropriate NAICS code(s) for a representative year to determine the percentage that the nationwide annualized costs represent of annual revenues. Like we do for capital expenditures, we combine the costs projected to be expended to comply with the standards for NSPS and the presumptive standards in the proposed EG to analyze the potential aggregate impact of the proposal. The EAV of the associated increase in compliance cost over the 2023 to 2035 period is projected to be about $1.2 billion without revenues from product recovery and about $760 million with revenues from product recovery (in 2019 dollars). Revenue data for relevant NAICS codes were obtained from the U.S. Census 2017 County Business Patterns and Economic Census, the most recent revenue figures available.[172] According to these data, 2018 receipts for the sector were about $358 billion in 2019 dollars. Comparing the EAV of the projected compliance costs under the proposal with the sector-level receipts figure yields a percentage of about 0.3 percent without revenues from product recovery and about 0.2 percent with revenues from product recovery. More data and analysis supporting the comparison of capital expenditures and annualized costs projected to be incurred under the rule and the sector-level capital expenditures and receipts is presented in Chapter 15 of the TSD for this action, which is in the public docket.

In considering the costs of the control options evaluated in this action, the EPA estimated the control costs under various approaches, including annual average cost-effectiveness and incremental cost-effectiveness of a given control. The EPA also performed two broad comparisons to consider the costs of control: First, we compared the projected compliance-related capital expenditures to recent sector-level capital expenditures; second, we compared the projected total compliance costs to recent sector-level annual revenues. In its cost-effectiveness analyses, the EPA recognized and took into account that these multi-pollutant controls reduce both VOC and methane emissions in equal proportions, as reflected in the single-pollutant and multipollutant cost effectiveness approaches. The EPA also considered cost saving from the natural gas recovered instead of vented due to the proposed controls. Based on all of the considerations described above, the EPA concludes that the costs of the controls that serve as the basis of the standards proposed in this action are reasonable. The EPA solicits comment on its approaches for considering control costs, as well as the resulting analyses and conclusions.

X. Summary of Proposed Action for NSPS OOOOa

As described above in sections IV and VIII, the 2020 Policy Rule rescinded all NSPS regulating emissions of VOC and methane from sources in the natural gas transmission and storage segment of the Oil and Natural Gas Industry and NSPS regulating methane from sources in the industry's production and processing segments. As a result, the 2020 Technical Rule only amended the VOC standards for the production and processing segments in the 2016 NSPS OOOOa, because those were the only standards that remained at the time that the 2020 Technical Rule was finalized. The 2020 Technical Rule included amendments to address a range of technical and implementation issues in response to administrative petitions for reconsideration and other issues brought to the EPA's attention since promulgating the 2016 NSPS. These included, among other issues, those associated with the implementation of the fugitive emissions requirements and pneumatic pump standards, provisions to apply for the use of an AMEL, provisions for determining applicability of the storage vessel standards, and modification to the engineer certifications. In 2018, the EPA proposed amendments to address these technical issues for both the methane and VOC standards in the 2016 NSPS OOOOa, and in some instances for sources in the transmission and storage segment. 83 FR 52056, October 15, 2018. However, because the methane standards and all standards for the transmission and storage segment were removed via the 2020 Policy Rule prior to the finalization of the 2020 Technical Rule, the final amendments in the 2020 Technical Rule apply only to the 2016 NSPS OOOOa VOC standards for the production and processing segments. Additionally, the 2020 Policy Rule amended the 2012 NSPS OOOO to remove the VOC requirements for sources in the transmission and storage segment, but the Technical Rule did not amend the 2012 NSPS OOOO.

Under the CRA, a rule that is subject to a joint resolution of disapproval ''shall be treated as though such rule had never taken effect.'' 5 U.S.C. 801(f)(2). Thus, because it was disapproved under the CRA, the 2020 Policy Rule is treated as never having taken effect. As a result, the requirements in the 2012 NSPS OOOO and 2016 NSPS OOOOa that the 2020 Policy Rule repealed (*i.e.,* the VOC and methane standards for the transmission and storage segment, as well as the methane standards for the production and processing segments) must be treated as being in effect immediately upon enactment of the joint resolution on June 30, 2021. Any new, reconstructed, or modified facility that would have been subject to the 2012 or 2016 NSPS (''affected facility'') but for the 2020 Policy Rule was subject to those NSPS as of that date. The CRA resolution did not address the 2020 Technical Rule; therefore, the amendments made in the 2020 Technical Rule, which apply only to the VOC standards for the production and processing segments in the 2016 NSPS OOOOa, remain in effect. As a result, sources in the production and processing segments are now subject to two different sets of standards:[173] One

[171] U.S. Census Bureau, 2019 Annual Capital Expenditures Survey, Table 4b. Capital Expenditures for Structures and Equipment for Companies With Employees by Industry: 2018 Revised, *http://www.census.gov/econ/aces/index.html,* accessed September 4, 2021.

[172] 2017 County Business Patterns and Economic Census. The Number of Firms and Establishments, Employment, Annual Payroll, and Receipts by Industry and Enterprise Receipts Size: 2017, *https://www.census.gov/programs-surveys/susb/data/tables.2017.html,* accessed September 4. 2021.

[173] The only exception is storage vessels, for which the EPA did not promulgate methane standards in the 2016 NSPS OOOOa.

for methane based on the 2016 NSPS OOOOa, and one for VOC that include the amendments to the 2016 NSPS OOOOa made in the 2020 Technical Rule. Sources in the transmission and storage segment are subject to the methane and VOC standards as promulgated in either the 2012 NSPS OOOO or the 2016 NSPS OOOOa, as applicable.[174] The EPA recognizes that certain amendments made to the VOC standards in the 2016 NSPS OOOOa in the 2020 Technical Rule, which addressed technical and implementation issues in response to administrative petitions for reconsideration and other issues brought to the EPA's attention since promulgating the 2016 NSPS OOOOa rule could also be appropriate to address similar implementation issues associated with the methane standards for the production and processing segments and the methane and VOC standards for the transmission and storage segment. In fact, as mentioned above, such revisions were proposed in 2018 but not finalized because these standards were removed by the 2020 Policy Rule prior to the EPA's promulgation of the 2020 Technical Rule. In light of the above, the EPA is proposing to revise 40 CFR part 60, subpart OOOOa, to apply certain amendments made in the 2020 Technical Rule to the 2016 NSPS OOOOa for methane from the production and processing segments and/or the 2016 NSPS OOOOa for methane and VOC from the transmission and storage segment, as specified in this section.

In this action, the EPA is proposing amendments to the 2016 NSPS OOOOa to (1) rescind the revisions to the VOC fugitive emissions monitoring frequencies at well sites and gathering and boosting compressor stations in the 2020 Technical Rule as those revisions were not supported by the record for that rule, or by our subsequent information and analysis, and (2) adjust other modifications made in the 2020 Technical Rule to address technical and implementation issues that result from the CRA disapproval of the 2020 Policy Rule. The EPA is not reopening any of these prior rulemakings for any other purpose in this proposed action. Specifically, the EPA is not reopening any of the determinations made in the 2012 NSPS OOOO. In the final rule for this action, the EPA will update the NSPS OOOO and NSPS OOOOa regulatory text in the CFR to reflect the CRA resolution's disapproval of the final 2020 Policy Rule, specifically, the reinstatement of the NSPS OOOO and NSPS OOOOa requirements that the 2020 Policy Rule repealed but that came back into effect immediately upon enactment of the CRA resolution. In accordance with 5 U.S.C. 553(b)(3)(B), the EPA is not soliciting comment on these updates. Moreover, the EPA is not reopening the methane standards as finalized in the 2016 NSPS OOOOa, except as to the specific issues discussed below, nor is the EPA reopening any other portions of the 2016 Rule. The EPA is also not reopening any determinations made in the 2020 Technical Rule, except as to the specific issues discussed below. Finally, the reopening of determinations made with respect to the VOC standards in the 2020 Technical Rule does not indicate any intent to also reopen the methane standards for the same affected facilities.

A. Amendments to Fugitive Emissions Monitoring Frequency

The EPA is proposing to repeal its amendments in the 2020 Technical Rule that (1) exempted low production well sites from monitoring fugitive emissions and (2) changed from quarterly to semiannual monitoring of VOC emissions at gathering and boosting compressor stations. The EPA has authority to reconsider a prior action ''as long as 'the new policy is permissible under the statute. . . , there are good reasons for it, and . . . the agency *believes* it to be better.' '' *FCC* v. *Fox Television Stations, Inc., 556 U.S. 502, 515, 129 S. Ct. 1800, 173 L. Ed. 2d738 (2009).*

The 2016 NSPS OOOOa, as initially promulgated, required semiannual monitoring of VOC and methane emissions at all well sites, including low production well sites. It also required quarterly monitoring of compressor stations, including gathering and boosting compressor stations. After issuing the 2020 Policy Rule, which removed all methane standards applicable to the production and processing segments and all methane and VOC standards applicable to the transmission and storage segment, the EPA promulgated the 2020 Technical Rule that further amended the VOC standards in the production and processing segment. In particular, based on its revised cost analyses, the EPA exempted low production well sites from monitoring VOC fugitive emissions and changed the frequency of monitoring VOC fugitive emissions from quarterly to semiannually at gathering and boosting compressor stations. However, as a result of the CRA disapproval of the 2020 Policy Rule, the low production well sites and the gathering and boosting compressor stations continue to be subject to semiannual and quarterly monitoring of methane emissions respectively. While it is possible for these affected facilities to comply with both the VOC and methane monitoring standards that are now in effect, as compliance with the more stringent standard would be deemed compliance with the other, the EPA reviewed its decisions to amend the VOC monitoring frequencies for these affected facilities as well as the underlying record and, for the reasons explained below, no longer believe that the amendments are appropriate. Therefore, the EPA is proposing to repeal these amendments and restore the semiannual and quarterly monitoring requirements for low production well sites and gathering and boosting compressor stations, as originally promulgated in the 2016 NSPS OOOOa, for both methane and VOC.

1. Low Production Well Sites

As mentioned above, low production well sites are subject to semiannual monitoring of fugitive methane emissions. The EPA is proposing to repeal the amendment in the 2020 Technical Rule exempting low production well sites from monitoring fugitive VOC emissions because the analysis for the 2020 Technical Rule supports retaining the semiannual monitoring requirement when regulating both VOC and methane emissions. While the 2020 Technical Rule amended only the VOC standards in the production and processing segments, the EPA evaluated both methane and VOC reductions in its final technical support document (TSD) (2020 TSD), including the costs associated with different monitoring frequencies under the multipollutant approach,[175] which the EPA considers a reasonable approach when regulating multiple pollutants. As shown in the 2020 TSD, under the multipollutant approach, the cost of semiannual monitoring at low production well sites is $850 per ton of methane and $3,058 per ton of VOC reduced, both of which are well within the range of what the

[174] For the EPA's full explanation of its initial guidance to stakeholders on the impact of the CRA, please see *https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.*

[175] For purposes of the multipollutant approach, we assume that emissions of methane and VOC are controlled at the same time, therefore, half of the cost is apportioned to the methane emission reductions and half of the cost is apportioned to VOC emission reductions.

EPA considers to be cost effective.[176] Nevertheless, the EPA stated in the 2020 Technical Rule that ''even if we had not rescinded the methane standards in the 2020 Policy Rule, we would still conclude that fugitive emissions monitoring, at any of the frequencies evaluated, is not cost effective for low production well sites.'' This statement, however, is inconsistent with the conclusions on what costs are reasonable for the control of methane emissions as discussed in this proposal in section IX. More importantly, as an initial matter, this statement was based on the EPA's observation in the 2020 Technical Rule that the $850 per ton of methane reduced is ''greater than the highest value for methane that the EPA determined to be reasonable in the 2016 NSPS subpart OOOOa,'' which the EPA incorrectly identified as $738/ton; the record for the 2016 NSPS OOOOa shows that the EPA considered value as high as $2,185/ton to be cost effective for methane reduction. 80 FR 56627; see also, NSPS OOOOa Final TSD at 93, Table 6–7. Further, even with the incorrect observation, the EPA did not conclude in the 2020 Technical Rule that $850 per ton of methane reduced is therefore unreasonable. 85 FR 57420. In fact, the EPA reiterated its prior determination that ''a cost of control of $738 per ton of methane reduced did not appear excessive,'' and that value was only $112 less than the value that the EPA had incorrectly identified as the highest methane cost-effectiveness value from the 2016 NSPS OOOOa. As discussed above, in fact $738/ton is well within the costs that the EPA concludes to be reasonable in the 2016 NSPS OOOOa as well as in this document. Also, as explained in section XI.A.2, due to the wide variation in well characteristics, types of oil and gas products and production levels, gas composition, and types of equipment at well sites, there is considerable uncertainty regarding the relationship between the fugitive emissions and production levels. Accordingly, the EPA no longer believes that production levels provide an appropriate threshold for any exemption from fugitive monitoring. See section XI.A.2 for additional discussion on the proposed emission thresholds for well site fugitive emissions in place of production-based model plants. In light of the above, the EPA is proposing to remove the exemption of low production well sites from fugitive VOC emissions monitoring, thereby restoring the semiannual monitoring requirement established in the 2016 NSPS OOOOa.

2. Gathering and Boosting Compressor Stations

The EPA is proposing to repeal its amendment to the VOC monitoring frequency for gathering and boosting compressor stations in the 2020 Technical Rule because the EPA believes that amendment was made in error. In that rule, the EPA noted that, based on its revised cost analysis, quarterly monitoring has a cost effectiveness of $3,221/ton of VOC emissions and an incremental cost of $4,988/ton of additional VOC emissions reduced between the semiannual and quarterly monitoring frequencies. While the EPA observed that semiannual monitoring is more cost effective than quarterly, the EPA nevertheless acknowledged that ''these values (total and incremental) are considered cost-effective for VOC reduction based on past EPA decisions, including the 2016 rulemaking.'' 85 FR 57421, September 15, 2020. The EPA instead identified two additional factors to support its decision to forgo quarterly monitoring. First, the EPA stated that the ''Oil and Gas Industry is currently experiencing significant financial hardship that may weigh against the appropriateness of imposing the additional costs associated with more frequent monitoring.'' However, the EPA did not offer any data regarding the financial hardship, significant or otherwise, the industry was experiencing. While the rule cited to several articles on the impact of COVID–19 on the industry, the EPA did not discuss any aspect of any of the cited articles that led to its conclusion of ''significant financial hardship'' on the industry. Nor did the EPA explain how reducing the frequency of a monitoring requirement that had been in effect since 2016 would meaningfully affect the industry's economic circumstances in any way or weigh those considerations against the forgone emission reductions that would result from reducing monitoring frequency.

Second, the EPA generally asserted that ''there are potential efficiencies, and potential cost savings, with applying the same monitoring frequencies for well sites and compressor stations.'' Again, the EPA did not describe what the potential efficiencies are or the extent of cost savings that would justify forgoing quarterly monitoring, or weigh those efficiencies and cost savings against the forgone emission reductions that would result from reducing the monitoring frequency for compressor stations. Nor did we explain why the Agency's 2016 BSER determination that quarterly monitoring was achievable and cost-effective was incorrect in light of these asserted efficiencies. On the contrary, based on the compliance records for the 2016 NSPS OOOOa, there is no indication that compressor stations experienced hardship or difficulty in complying with the quarterly monitoring requirement. Further, as discussed in section XII.A.1.b, our analysis for NSPS OOOOb and EG OOOOc confirms that quarterly monitoring remains both achievable and cost-effective for compressor stations, and several State agencies also have rules that require quarterly monitoring at compressor stations. For the reasons stated above, the EPA concludes that it lacked justification and thus erred in revising the VOC monitoring frequency for gathering and boosting compressor stations from quarterly to semiannual. The EPA is therefore proposing to repeal that amendment, thereby restoring the quarterly monitoring requirement for gathering and boosting compressor stations, as established in the 2016 NSPS OOOOa.

B. Technical and Implementation Amendments

In the following sections, the EPA describes a series of proposed amendments to 2016 NSPS OOOOa for methane to align the 2016 methane standards with the current VOC standards (which were modified by the 2020 Technical Rule). We describe the supporting rationales that were provided in the 2020 Technical Rule for modifying the requirements applicable to the VOC standards, and explain why the amendments would also appropriately apply to the reinstated methane standards.

1. Well Completions

In the 2020 Technical Rule, the EPA made certain amendments to the VOC standards for well completions in the 2016 NSPS OOOOa. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to apply the same amendments to the methane standards for well completions in the 2016 NSPS OOOOa.

First, the EPA is proposing to amend the 2016 NSPS OOOOa methane standards for well completions to allow

[176] See 2020 NSPS OOOOa Technical Rule TSD at Docket ID No. EPA–HQ–OAR–2017–0483–2291. See also section IX, which provides that the cost effectiveness values for the controls that we have identified as BSER in this action range from $2,200/ton to $5,800/ton VOC reduction and $700/ton to $2,100/ton of methane reduction. As explained in that section, these controls reflect emission reduction technologies and methods that many owners and operators in the oil and gas industry have employed for years, either voluntarily or due to the 2012 and 2016 NSPS, as well as State or other requirements.

the use of a separator at a nearby centralized facility or well pad that services the well affected facility during flowback, as long as the separator can be utilized as soon as it is technically feasible for the separator to function. The well completion requirements, as promulgated in 2016, had required that the owner or operator of a well affected facility have a separator on site during the entire flowback period. 81 FR 35901, June 3, 2016. In the 2020 Technical Rule, the EPA amended this provision to allow the separator to be at a nearby centralized facility or well pad that services the well affected facility during flowback as long as the separator can be utilized as soon as it is technically feasible for the separator to function. See 40 CFR 60.5375a(a)(1)(iii). As explained in that rulemaking (85 FR 57403) and previously in the 2016 NSPS OOOOa final rule preamble, ''[w]e anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate reduced emission completion (REC) equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use.'' 81 FR 35852, June 3, 2016. For the same reason, the EPA is proposing to make the same amendment to the methane standards for well completions.

Additionally, the 2020 Technical Rule amended 40 CFR 60.5375a(a)(1)(i) to clarify that the separator that is required during the initial flowback stage may be a production separator as long as it is also designed to accommodate flowback. As explained in the preamble to the final 2020 Technical Rule, when a production separator is used for both well completions and production, the production separator is connected at the onset of the flowback and stays on after flowback and at the startup of production. 85 FR 57403, September 15, 2020. For the same reason, the EPA is proposing the same clarification apply to the methane standards for well completions.

The 2020 Technical Rule also amended the definition of flowback. In 2016, the EPA defined ''flowback'' as 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. 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. 81 FR 35934, June 3, 2016.

The 2020 Technical Rule amended this definition by adding a clarifying statement that ''[s]creenouts, coil tubing cleanouts, and plug drill-outs are not considered part of the flowback process.'' 40 CFR 60.5430a. In the proposal for the 2020 Technical Rule, the EPA explained that screenouts, coil tubing cleanouts, and plug drill outs are functional processes that allow for flowback to begin; as such, they are not part of the flowback. 83 FR 52082, October 15, 2018. In conjunction with this amendment, the 2020 Technical Rule added definitions for screenouts, coil tubing cleanouts, and plug drill outs. See 40 CFR 60.5430a. Specifically, a screenout is an attempt to clear proppant from the wellbore in order to dislodge the proppant out of the well. A coil tubing cleanout is a process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. A plug drill-out is the removal of a plug (or plugs) that was used to isolate different sections of the well. For the reason stated above, the EPA is proposing to apply the definitions of flowback, screenouts, coil tubing cleanouts, and plug drill outs that were finalized in the 2020 Technical Rule to the methane standards for well completions in the 2016 NSPS OOOOa.

Finally, the 2020 Technical Rule amended specific recordkeeping and reporting requirements for the VOC standards for well completions, and the EPA is proposing to apply these amendments to the methane standards for well completions in the 2016 NSPS OOOOa. For the reasons explained in 83 FR 52082, the 2020 Technical Rule requires that for each well site affected facility that routes flowback entirely through one or more production separators, owners and operators must record and report only the following data elements:

- Well Completion ID;
- Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983;
- U.S. Well ID;
- The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production; and
- The date and time of the startup of production.

While the 2020 Technical Rule removed certain reporting requirements (*e.g.,* information about when a separator is hooked up or disconnected during flowback) as unnecessary or redundant, 85 FR 57403, the rule added a requirement that for periods where salable gas is unable to be separated, owners and operators must record and report the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations.

As explained in the preamble to the proposal for the 2020 Technical Rule, when a production separator is used for both well completions and production, the production separator is connected at the onset of the flowback and stays on after flowback and at the startup of production; in that event, certain reporting and recordkeeping requirements associated with well completions (*e.g.,* information about when a separator is hooked up or disconnected during flowback) would be unnecessary. 83 FR 52082. Because these amendments to the recordkeeping and reporting requirements associated with well completion are independent of the specific pollutant being regulated, we are proposing these same amendments to the methane standards for well completions in the 2016 NSPS OOOOa.

2. Pneumatic Pumps

In the 2020 Technical Rule, the EPA made certain amendments to the VOC standards for pneumatic pumps in the 2016 NSPS OOOOa. For the same reasons provided in the 2020 Technical Rule, along with further explanation provided below, the EPA is proposing to apply the same amendments to the methane standards for pneumatic pumps in the 2016 NSPS OOOOa.

First, the EPA is proposing to amend the 2016 NSPS OOOOa methane standards for pneumatic pumps to expand the technical infeasibility provision to apply to pneumatic pumps at greenfield sites. Under the 2016 NSPS OOOOa, ''emissions from new, modified, and reconstructed natural gas-driven diaphragm pumps located at well sites [must] be reduced by 95 percent if either a control device or the ability to route to a process is already available onsite, unless it is technically infeasible at sites other than new developments (*i.e.,* greenfield sites).'' 81 FR 35824 and 35844. For the 2016 NSPS OOOOa, the EPA concluded that circumstances that could otherwise make control of a pneumatic pump technically infeasible

at an existing location could be addressed in the design and construction of a greenfield site. 81 FR 35849 and 35850 (June 3, 2016). Concerns raised in petitions for reconsideration on the 2016 NSPS OOOOa explained that, even at greenfield sites, certain scenarios present circumstances where the control of a pneumatic pump may be technically infeasible despite the site being newly designed and constructed.[177] These circumstances include, but are not limited to, site designs requiring high-pressure flares to which routing a low-pressure pump discharge is not feasible and use of small boilers or process heaters that are insufficient to control pneumatic pump emissions or that could result in safety trips and burner flame instability. The EPA proposed to extend the technical infeasibility exemption to greenfield sites in 2018 and sought comment on these circumstances that could preclude control of a pneumatic pump at greenfield sites. While the EPA received comments both in favor of and opposing the application of the technical infeasibility exemption to greenfield sites, the commenters did not identify a reasoned basis for the EPA to decline to extend the exemption. See Response to Comments (RTC) for 2020 Technical Rule at 5–1 to 5–4 at Docket ID No. EPA–HQ–OAR–2017–0483. Moreover, the EPA specifically sought information regarding the additional costs that would be incurred if owners and operators of greenfield sites were required to select a control that can accommodate pneumatic pump emissions in addition to the control's primary purpose at a new construction site, but no such information was provided.

The 2020 Technical Rule therefore expanded the technical infeasibility provision to apply to pneumatic pumps at all well sites, including new developments (greenfield sites), concluding that the extension was appropriate because the EPA identified circumstances where it may not be technically feasible to control pneumatic pumps at a greenfield site. The 2020 Technical Rule removed the reference to greenfield site in 40 CFR 60.5393a(b) and the associated definition of greenfield site at 40 CFR 60.5430a.

In the final rule preamble for the 2016 NSPS OOOOa, the EPA stated we did not intend to require the installation of a control device at a well site for the sole purpose of controlling emissions from a pneumatic pump, but rather only required control of pneumatic pumps to the extent a control device or process would already be available on site. It is not the EPA's intent to require a greenfield site to install a control device specifically for controlling emissions from a pneumatic pump. It is our understanding that sites are designed to maximize operation and safety. This includes the placement of equipment, such as control devices. Because vented gas from pneumatic pumps is at low pressure, it may not be feasible to move collected gas through a closed vent system to a control device, depending on site design. Therefore, the EPA continues to conclude that, when determining technical feasibility at any site, such a determination should consider the routing of pneumatic pump emissions to the controls which are needed for the other processes at the site (*i.e.,* not the pneumatic pump). The owner or operator must justify and provide professional or in-house engineering certification for any site where the control of pneumatic pump emissions is technically infeasible. As explained in the RTC for the 2020 Technical Rule, ''[t]he EPA believes that the requirement to certify an engineering assessment to demonstrate technical infeasibility provides protection against an owner or operator purposely designing a new site just to avoid routing emissions from a pneumatic pump to an onsite control device or to a process.'' [178] For the reasons explained above, the EPA is proposing to align the methane standards in the 2016 NSPS OOOOa for controlling pneumatic pump emissions with the amendments made to the VOC standards in the 2020 Technical Rule to allow for a well-justified determination of technical infeasibility at all well sites, including greenfield sites.

Second, the 2020 Technical Rule amended the 2016 NSPS OOOOa to specify that boilers and process heaters are not considered control devices for the purposes of the pneumatic pump standards. It is the EPA's understanding, based on information provided in reconsideration petitions [179] submitted regarding the 2016 NSPS OOOOa and comments received on the proposal for the 2020 Technical Rule, that some boilers and process heaters located at well sites are not inherently designed for the control of emissions. While it is true that for some other sources (not pneumatic pumps), boilers and process heaters may be designed as control devices, that is generally not the operational purpose of this equipment at a well site. Instead, it is the EPA's understanding that boilers and process heaters operate seasonally, episodically, or otherwise intermittently as process devices, thus making the use of these devices as controls inefficient and non-compliant with the continuous control requirements at 40 CFR 60.5415a.[180] Further, as explained in the 2020 Technical Rule, the fact that some boilers and process heaters located at well sites are not inherently designed to control emissions means that ''routing pneumatic pump emissions to these devices may result in frequent safety trips and burner flame instability (*e.g.,* high temperature limit shutdowns and loss of flame signal).'' *Id.* The EPA determined that ''requiring the technical infeasibility evaluation for every boiler and process heater located at a wellsite would result in unnecessary administrative burden since each such evaluation would be raising the[se] same concerns.'' 85 FR 57404 (September 15, 2020). Further, as described above, the EPA did not intend to require the installation of a control device for the sole purpose of controlling emissions from pneumatic pumps. Based on the EPA's understanding that boilers and process heaters located at well sites are designed and operated as process equipment (meaning they are not inherently designed for the control of emissions), the EPA also does not intend to require their continuous operation solely to control emissions from pneumatic pumps either. Therefore, the EPA is proposing to align the methane standards for pneumatic pumps with the 2020 Technical Rule to specify that boilers and process heaters are not considered control devices for the purposes of controlling pneumatic pump emissions. The EPA solicits comment on this alignment, including whether there are specific examples where boilers and process heaters are

[177] See proposal for 2020 Technical Rule at 83 FR 52061.

[178] See Docket ID No. EPA–HQ–OAR–2017–0483–2291. ''For example, consider the example provided by one commenter where a new site design requires only a high-pressure flare to control emergency and maintenance blowdowns and it is not feasible for a low-pressure pneumatic pump discharge to be routed to such a flare. The infeasibility determination would need not only demonstrate that it is not feasible for a low-pressure pneumatic pump discharge to be directly routed to the flare, it would also need to demonstrate that it is infeasible to design and install a low-pressure header to allow routing this discharge to such a flare system.'' RTC at 5–4.

[179] See Docket ID No. EPA–HQ–OAR–2017–0483–0016.

[180] See Docket ID No. EPA–HQ–OAR–2017–0483–0016.

currently used as control devices at well sites.

Third, the EPA is proposing to align the certification requirements for the determination that it is technically infeasible to route emissions from a pneumatic pump to a control device or process. The 2016 NSPS OOOOa required certification of technical infeasibility by a qualified third-party Professional Engineer (PE); however, the 2020 Technical Rule allows this certification by either a PE or an in-house engineer, because in-house engineers may be more knowledgeable about site design and control than a third-party PE. The EPA continues to believe that certification by an in-house engineer is appropriate for this purpose. We are, therefore, proposing to align the methane standards in the 2016 NSPS OOOOa with the 2020 Technical Rule to allow certification of technical infeasibility by either a PE or an in-house engineer with expertise on the design and operation of the pneumatic pump. We are soliciting comment on this proposed alignment.

3. Closed Vent Systems (CVS)

As in the 2020 Technical Rule, the EPA is proposing to allow multiple options for demonstrating that there are no detectable methane emissions from CVS. Additionally, the EPA is proposing to allow either a PE or an in-house engineer with expertise on the design and operation of the CVS to certify the design and operation will meet the requirement to route all vapors to the control device or back to the process.

The methane standards in the 2016 NSPS OOOOa require that CVS be operated with no detectable emissions, as demonstrated through specific monitoring requirements associated with the specific affected facilities (*i.e.,* pneumatic pumps, centrifugal compressors, reciprocating compressors, and storage vessels). Relevant here, the 2016 NSPS OOOOa required this demonstration for both VOC and methane emissions through annual inspections using EPA Method 21 for CVS associated with pneumatic pumps, while requiring storage vessels to conduct monthly audio, visual, olfactory (AVO) monitoring. The 2020 Technical Rule amended the VOC requirements for CVS for pneumatic pumps to align the requirements for pneumatic pumps and storage vessels by incorporating provisions allowing the option to demonstrate the pneumatic pump CVS is operated with no detectable emissions by either an annual inspection using EPA Method 21, monthly AVO monitoring, or OGI monitoring at the frequencies specified for fugitive emissions monitoring. The EPA is proposing to amend the methane standards to allow pneumatic pump affected facilities to permit these same options to demonstrate no detectable methane emissions from CVS either using annual Method 21 monitoring, as currently required by the 2016 NSPS OOOOa, or using either monthly AVO monitoring or OGI monitoring at the fugitive monitoring frequency. The EPA considers these detection options appropriate for CVS associated with pneumatic pumps because any of the three would detect methane as well as VOC emissions. We incorporated the option for monthly AVO monitoring in the 2020 Technical Rule because pneumatic pumps and controlled storage vessels are commonly located at the same site and having separate monitoring requirements for a potentially shared CVS is overly burdensome and duplicative. 83 FR 52083 (October 15, 2018). We further incorporated the option for OGI monitoring because OGI is already being used for those sites that are subject to fugitive emissions monitoring and the CVS can readily be monitored during the fugitive emissions survey at no extra cost. 85 FR 57405. The EPA believes it is appropriate to maintain these options because not all well sites with controlled pneumatic pumps will be subject to fugitive emissions monitoring (*e.g.,* pneumatic pumps located at existing well sites that have not triggered the fugitive monitoring requirements for new or modified well sites) and requiring either OGI or EPA Method 21 survey of the CVS for the pneumatic pump in the absence of fugitive emissions surveys would be unreasonable. It is possible for a new pneumatic pump to be subject to control at an existing well site that is not subject to the fugitive emissions requirements. Requiring either EPA Method 21 or OGI for the sole purpose of monitoring the CVS associated with the pneumatic pump would be too costly,[181] therefore we continue to believe monthly AVO is an appropriate option for pneumatic pumps subject to the 2016 NSPS OOOOa.

Additionally, the 2020 Technical Rule amended the 2016 NSPS OOOOa to allow certification of the design and operation of CVS by an in-house engineer with expertise on the design and operation of the CVS in lieu of a PE. This certification is necessary to ensure the design and operation of the CVS will meet the requirement to route all vapors to the control device or back to the process. As explained in the proposal for the 2020 Technical Rule, 83 FR 52079, the EPA allows CVS certification by either a PE or an in-house engineer because in-house engineers may be more knowledgeable about site design and control than a third-party PE. For the same reason, the EPA is proposing to amend the CVS requirements associated with methane emissions in the production and processing segments, and methane and VOC emissions in the transmission and storage segment, to allow certification of the design and operation of CVS by either a PE or an in-house engineer with expertise on the design and operation of the CVS.

4. Fugitive Emissions at Well Sites and Compressor Stations

a. Well Sites

The EPA is proposing to exclude from fugitive emissions monitoring a well site that is or later becomes a ''wellhead only well site,'' which the 2020 Technical Rule defines as ''a well site that contains one or more wellheads and no major production and processing equipment.'' The 2016 NSPS OOOOa excludes well sites that contain only one or more wellheads from the fugitive emissions requirements because fugitive emissions at such well sites are extremely low. 80 FR 56611. As explained in that rulemaking, ''[s]ome well sites, especially in areas with very dry gas or where centralized gathering facilities are used, consist only of one or more wellheads, or 'Christmas trees,' and have no ancillary equipment such as storage vessels, closed vent systems, control devices, compressors, separators and pneumatic controllers. Because the magnitude of fugitive emissions depends on how many of each type of component (*e.g.,* valves, connectors, and pumps) are present, fugitive emissions from these well sites are extremely low.'' 80 FR 56611. The 2020 Technical Rule amended the 2016 NSPS OOOOa to exclude from fugitive emissions monitoring a well site that is or later becomes a ''wellhead only well site,'' which the 2020 Technical Rule defines as ''a well site that contains one or more wellheads and no major production and processing equipment.'' The 2020 Technical Rule defined ''major production and processing equipment''

[181] Both OGI and EPA Method 21 have significant capital and annual costs, including the cost of specialized equipment and trained operators of that equipment. While the costs of these programs are justified for well site fugitive emission monitoring based on the assumption of a high component count from which emissions would be controlled, the CVS is only one of those many components. Thus, where well site fugitive monitoring is not otherwise required, the cost-effectiveness of OGI or EPA Method 21 would be significantly higher for the CVS alone.

as including reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water. We continue to believe that available information, including various studies,[182] supports an exemption for well sites that do not have this major production and processing equipment. The 2020 Technical Rule allows certain small ancillary equipment, such as chemical injection pumps, pneumatic controllers used to control well emergency shutdown valves, and pumpjacks, that are associated with, or attached to, the wellhead and ''Christmas tree'' to remain at a ''wellhead only well site'' without being subject to the fugitive emissions monitoring requirements because they have very few fugitive emissions components that would leak, and therefore have limited potential for fugitive emissions. The emission reduction benefits of continuing monitoring at that point would be relatively low, and thus would not be cost-effective.

For the reason stated above, the EPA is proposing to amend the 2016 NSPS OOOOa to allow monitoring of methane fugitive emissions to stop when a wellsite contains only wellhead(s) and no major production and processing equipment, as provided in the 2020 Technical Rule.

b. Compressor Stations

As discussed above, the 2016 NSPS OOOOa required quarterly monitoring of compressor stations for both VOC and methane emissions, and it also permitted waiver from one quarterly monitoring event when the average temperature is below 0 °F for two consecutive months because it is technically infeasible for the OGI camera (and EPA Method 21 instruments) to operate below this temperature. After the 2020 Policy Rule rescinded the methane standards, the 2020 Technical Rule reduced the monitoring requirements for the VOC standards to require only semiannual monitoring and, in doing so, removed the waiver. Upon enactment of the CRA resolution, compressor stations again became subject to quarterly monitoring pursuant to the reinstated 2016 NSPS OOOOa methane standards, and the waiver as it applied to the methane standards was also reinstated. Consistent with our proposal to align the monitoring requirements for VOCs with the monitoring requirements for methane, the EPA is also proposing to reinstate the waiver for the VOC standards as specified in the 2016 NSPS OOOOa.

c. Well Sites and Compressor Stations on the Alaska North Slope

The EPA is proposing to amend the 2016 NSPS OOOOa to require that new, reconstructed, and modified compressor stations located on the Alaska North Slope that startup (initially, or after reconstruction or modification) between September and March to conduct initial monitoring of methane emissions within 6 months of startup, or by June 30, whichever is later. The EPA made a similar amendment to the initial monitoring of methane and VOC emissions at well sites located on the Alaska North Slope in the March 12, 2018 amendments to the 2016 NSPS OOOOa (''2018 NSPS OOOOa Rule'').[183] As explained in that action, such separate requirements were warranted due to the area's extreme cold temperatures, which for approximately half of the year are below the temperatures at which the monitoring instruments are designed to operate. The 2020 Technical Rule made this amendment for VOC emissions from gathering and boosting compressor stations located in the Alaska North Slope for this same reason.

The EPA is also proposing to amend the 2016 NSPS OOOOa to require annual monitoring of methane and VOC emissions at all compressor stations located on the Alaska North Slope, with subsequent annual monitoring at least 9 months apart but no more than 13 months apart. In the 2018 NSPS OOOOa Rule, the EPA similarly amended the monitoring frequency for well sites located on the Alaska North Slope to annual monitoring to accommodate the extreme cold temperature. 83 FR 10628 (March 12, 2018). For the same reason, in the 2020 Technical Rule, the EPA amended the 2016 NSPS OOOOa to require annual VOC monitoring at gathering and boosting compressor stations located on the Alaska North Slope because extreme cold temperatures make it technically infeasible to conduct OGI monitoring for over half of a year.[184] Because the same difficulties would arise with respect to monitoring for fugitive methane emissions from gathering and boosting compressor stations or to monitoring of methane and VOC emissions from compressor stations in the transmission and storage segment, the EPA is proposing to amend the 2016 NSPS OOOOa to require that all compressor stations located on the Alaska North Slope conduct annual monitoring of both methane and VOC emissions.

Further, the EPA is proposing to extend the deadline for conducting initial monitoring of both VOC and methane emissions from 60 days to 90 days for all well sites and compressor stations located on the Alaska North Slope that startup or are modified between April and August. In the 2020 Technical Rule, the EPA made this amendment for initial VOC monitoring to allow the well site or gathering and boosting compressor station to reach normal operating conditions. 85 FR 57406. For the same reason, we are proposing to further amend the 2016 NSPS OOOOa to apply this same 90-day initial monitoring requirement to initial monitoring of fugitive methane and VOC emissions from all well sites and compressor stations located on the Alaska North Slope that startup or are modified between April and August.

d. Modification

The 2016 NSPS OOOOa, as originally promulgated, provided that ''[f]or purposes of the fugitive emissions standards at 40 CFR 60.5397a, [a] 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).'' 40 CFR 60.5430a. However, the original 2016 NSPS OOOOa defined ''modification'' only with respect to a well site and was silent on what constitutes modification to a well site that is a separate tank battery surface site. Specifically, 40 CFR 60.5365a(i), as promulgated in 2016, specified that, for the purposes of fugitive emissions components at a well site, a modification occurs when (1) a new well is drilled at an existing well site, (2) a well is hydraulically fractured at an existing well site, or (3) a well is hydraulically refractured at an existing well site. See 40 CFR 60.5365a(i).

Because this provision was silent on when modification occurs at a well site that is a separate tank battery surface site, the 2020 Technical Rule added language to clarify that a modification of a well site that is a separate tank battery surface site occurs when (1) any of the actions listed above for well sites occurs

[182] See *https://pubs.acs.org/doi/10.1021/acs.est.0c02927, https://data.permianmap.org/pages/flaring,* and *https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf.*

[183] 83 FR 10628 (March 12, 2018).

[184] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682 and EPA–HQ–OAR–2010–0505–12434. See also FLIR Systems, Inc. product specifications for GF300/320 model OGI cameras at *http://www.flir.com/ogi/display/?id=55671* and Thermo Fisher Scientific product specification for TVA–2020 at *https://assets.thermofisher.com/TFS-Assets/LSG/Specification-Sheets/EPM-TVA2020.pdf.*

at an existing separate tank battery surface site, (2) a well modified as described above sends production to an existing separate tank battery surface site, or (3) a well site subject to the fugitive emissions requirements removes all major production and processing equipment such that it becomes a wellhead-only well site and sends production to an existing separate tank battery surface site. Because the 2020 Technical Rule amended only the VOC standards in the 2016 NSPS OOOOa, and since this definition of modification equally applies to fugitive methane emissions from a separate tank battery surface site, the EPA is proposing to apply this definition of modification for purposes of determining when modification occurs at a separate tank battery surface site triggering the methane standards for fugitive emissions at well sites.

e. Initial Monitoring for Well Sites and Compressor Stations

The 2016 NSPS OOOOa, as originally promulgated, had required monitoring of methane and VOC fugitive emissions at well sites and compressor stations to begin within 60 days of startup (of production in the case of well sites) or modification. The 2020 Technical Rule extended this time frame to 90 days for well sites and gathering and boosting compressor stations in response to comments stating that well sites and compressor stations do not achieve normal operating conditions within the first 60 days of startup and suggesting that the EPA allow 90 days to 180 days. The EPA agreed that additional time to allow the well site or compressor station to reach normal operating conditions is warranted, considering the purpose of the initial monitoring is to identify any issues associated with installation and startup of the well site or compressor station. By providing sufficient time to allow owners and operators to conduct the initial monitoring survey during normal operating conditions, the EPA expects that there will be more opportunity to identify and repair sources of fugitive emissions, whereas a partially operating site may result in missed emissions that remain unrepaired for a longer period of time. 85 FR 57406. These same reasons apply regardless of pollutant or the location of the compressor station; therefore, the EPA is proposing to further amend the 2016 NSPS OOOOa to extend the deadline for conducting initial monitoring from 60 to 90 days for monitoring both VOC and methane fugitive emissions at all well sites and compressor stations (except those on the Alaska North Slope which are separately regulated as discussed in section X.B.4.c).

f. Repair Requirements

The 2020 Technical Rule made certain amendments to the 2016 NSPS OOOOa repair requirements associated with monitoring of fugitive VOC emissions at well sites and gathering and boosting compressor stations. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly amend the 2016 NSPS OOOOa repair requirements associated with monitoring of methane emissions at well sites and gathering and boosting compressor stations and monitoring of VOC and methane fugitive emissions at compressor stations in the transmission and storage segment.

Specifically, the EPA is proposing to require a first attempt at repair within 30 days of identifying fugitive emissions and final repair, including the resurvey to verify repair, within 30 days of the first attempt at repair. The 2016 NSPS OOOOa, as originally promulgated, required repair within 30 days of identifying fugitive emissions and a resurvey to verify that the repair was successful within 30 days of the repair. Stakeholders raised questions regarding whether emissions identified during the resurvey would result in noncompliance with the repair requirement. In the 2020 Technical Rule, the EPA clarified that repairs should be verified as successful prior to the repair deadline and added definitions for the terms ''first attempt at repair'' and ''repaired.'' Specifically, the definition of ''repaired'' includes the verification of successful repair through a resurvey of the fugitive emissions component. The EPA is similarly proposing to apply these amendments to the repair requirements made in the 2020 Technical Rule to the repair requirements associated with monitoring of methane emissions at well sites and gathering and boosting compressor stations as well as monitoring of VOC and methane fugitive emissions at compressor stations in the transmission and storage segment and monitoring.

In addition, the EPA is proposing that delayed repairs be completed during the ''next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest.'' The proposed amendment would clarify that completion of delayed repairs is required during scheduled shutdown for maintenance, and not just any shutdown.

In 2018 NSPS OOOOa Rule the EPA amended the 2016 NSPS OOOOa to specify that, where the repair of a fugitive emissions component 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 must be completed during the next scheduled compressor station shutdown, well shutdown, well shut-in, after a planned vent blowdown, or within 2 years, whichever is earlier.'' [185] During the rulemaking for the 2020 Technical Rule, the EPA received comments expressing concerns with requiring repairs during the next scheduled compressor station shutdown, without regard to whether the shutdown is for maintenance purposes. The commenters stated that repairs must be scheduled and that where a planned shutdown is for reasons other than scheduled maintenance, completion of the repairs during that shutdown may be difficult and disrupt gas transmission. The EPA agrees that requiring the completion of delayed repairs only during those scheduled compressor station shutdowns where maintenance activities are scheduled is reasonable and anticipates that these maintenance shutdowns occur on a regular schedule. Accordingly, in the 2020 Technical Rule the EPA further amended this provision by adding the term ''for maintenance'' to clarify that repair must be completed during the ''next scheduled compressor station shutdown for maintenance'' or other specified scheduled events, or within 2 years, whichever is the earliest. For the same reason, the EPA is proposing the same clarifying amendment to the delay of repair requirements for fugitive methane emissions at well sites and gathering and boosting compressor stations and fugitive VOC and methane fugitive emissions at compressor stations in the transmission and storage segment.

g. Definitions Related to Fugitive Emissions at Well Sites and Compressor Stations

The 2020 Technical Rule made certain amendments to the definition of a well site and the definition for startup of production as they relate to fugitive VOC emissions requirements at well sites. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly amend these definitions as they relate to the fugitive methane emissions requirements at well sites.

[185] 83 FR 10638, 40 CFR 60.5397a(h)(2).

The 2020 Technical Rule amended the definition of well site, for purposes of VOC fugitive emissions monitoring, to exclude equipment owned by third parties and oilfield solid waste and wastewater disposal wells. The amended definition for ''well site'' excludes third party equipment from the fugitive emissions requirements by excluding ''the flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components located downstream of this flange.'' To clarify this exclusion, the 2020 Technical Rule defines ''custody meter'' as ''the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination,'' and the ''custody meter assembly'' as ''an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter.'' This exclusion was added for several reasons, including consideration that owners and operators may not have access or authority to repair this third-party equipment and because the custody meter ''is used effectively as the cash register for the well site and provides a clear separation for the equipment associated with production of the well site, and the equipment associated with putting the gas into the gas gathering system.'' 83 FR 52077 (October 15, 2018).

The definition of a well site was also amended in the 2020 Technical Rule to exclude Underground Injection Control (UIC) Class I oilfield disposal wells and UIC Class II oilfield wastewater disposal wells. The EPA had proposed to exclude UIC Class II oilfield wastewater disposal wells because of our understanding that they have negligible fugitive VOC and methane emissions. 83 FR 52077. Comments received on the 2020 Technical rulemaking effort further suggested, and the EPA agreed, that we also should exclude UIC Class I oilfield disposal wells because of their low VOC and methane emissions. Both types of disposal wells are permitted through UIC programs under the Safe Drinking Water Act for protection of underground sources of drinking water. For consistency, the 2020 Technical Rule adopted the definitions for UIC Class I oil field disposal wells and UIC Class II oilfield wastewater disposal wells under the Safe Drinking Water Act definitions in excluding them from the definition of a well site in the 2016 NSPS OOOOa. Specifically, the 2020 Technical Rule defined a UIC Class I oilfield disposal well as ''a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations.'' Additionally, the 2020 Technical Rule defines a UIC Class II oilfield wastewater disposal well as ''a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.'' As amended, UIC Class I and UIC Class II disposal wells are not considered well sites for the purposes of VOC fugitive emissions requirements. Because the 2020 Technical Rule, as finalized, addressed only VOC emissions in the production and processing segment, the EPA is proposing the same exclusion and definition of ''well site'' for the purposes of fugitive emissions monitoring of methane emissions at well sites.

The EPA is also proposing to apply the definition for ''startup of production'' for purposes of well site fugitive emissions requirements for VOC to these requirements as they relate to methane. The 2016 NSPS OOOOa initially contained a definition for ''startup of production'' as it relates to the well completion standards that reduce emissions from hydraulically fractured wells. For that purpose, the term was defined as ''the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.'' 81 FR 25936 (June 3, 2016). The 2020 Technical Rule amended the definition of ''startup of production'' to separately define the term as it relates to fugitive VOC emissions requirements at well sites. Specifically, ''. . .[f]or the purposes of the fugitive monitoring requirements of 40 CFR 60.5397a, *startup of production* means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water'' 85 FR 57459 (September 15, 2020). This separate definition clarifies that fugitive emissions monitoring applies to both conventional and unconventional (hydraulically fractured) wells. For this same reason, the EPA is proposing to apply this same definition of ''startup of production'' to fugitive emissions monitoring of methane emissions at well sites.

h. Monitoring Plan

The 2016 NSPS OOOOa, as originally promulgated, required that each fugitive emissions monitoring plan include a site map and a defined observation path to ensure that the OGI operator visualizes all of the components that must be monitored during each survey. The 2020 Technical Rule amended this requirement to allow the company to specify procedures that would meet this same goal of ensuring every component is monitored during each survey. While the site map and observation path are one way to achieve this, other options can also ensure monitoring, such as an inventory or narrative of the location of each fugitive emissions component. The EPA stated in the 2020 Technical Rule that ''these company-defined procedures are consistent with other requirements for procedures in the monitoring plan, such as the requirement for procedures for determining the maximum viewing distance and maintaining this viewing distance during a survey.'' 85 FR 57416 (September 15, 2020). Because the same monitoring device is used to monitor both methane and VOC emissions, the same company-defined procedures for ensuring each component is monitored are appropriate. Therefore, the EPA is proposing to similarly amend the monitoring plan requirements for methane and for compressor stations to allow company procedures in lieu of a sitemap and an observation path.

i. Recordkeeping and Reporting

The 2020 Technical Rule amended the 2016 NSPS OOOOa to streamline the recordkeeping and reporting requirements for the VOC fugitive emissions standards. The amendments removed the requirement to report or keep certain records that the EPA determined were redundant or unnecessary; in some instances, the rule replaced those requirements or added new requirements that could better demonstrate and ensure compliance, in particular where the underlying requirement was also amended (*e.g.,* repair requirements). These amendments reflect consideration of the public comments received on the proposal for that rulemaking. The purpose and function of the recordkeeping and reporting requirements are equally applicable to methane and VOCs, and therefore, are not pollutant specific. For the same reasons the EPA streamlined these requirements in the 2020 Technical Rule,[186] the EPA is proposing to apply these streamlined recordkeeping and reporting requirements for methane

[186] See 85 FR 57415 (September 15, 2020).

emissions from sources subject to NSPS OOOOa.

For each collection of fugitive emissions components located at a well site or compressor station, the following amendments were made to the recordkeeping and reporting requirements in the 2020 Technical Rule:

- Revised the requirements in 40 CFR 60.5397a(d)(1) to require inclusion of procedures that ensure all fugitive emissions components are monitored during each survey within the monitoring plan.
- Removed the requirement to maintain records of a digital photo of each monitoring survey performed, captured from the OGI instrument used for monitoring when leaks are identified during the survey because the records of the leaks provide proof of the survey taking place.
- Removed the requirement to maintain records of the number and type of fugitive emissions components or digital photo of fugitive emissions components that are not repaired during the monitoring survey once repair is completed and verified with a resurvey.
- Required records of the date of first attempt at repair and date of successful repair.
- Revised reporting to specify the type of site (*i.e.,* well site or compressor station) and when the well site changes status to a wellhead-only well site.
- Removed requirement to report the name or ID of operator performing the monitoring survey.
- Removed requirement to report the number and type of difficult-to-monitor and unsafe-to-monitor components that are monitored during each monitoring survey.
- Removed requirement to report the ambient temperature, sky conditions, and maximum wind speed.
- Removed requirement to report the date of successful repair.
- Removed requirement to report the type of instrument used for resurvey.

5. AMEL

The 2020 Technical Rule made the following amendments to the provisions associated with applications for use of an AMEL for VOC work practice standards for well completions, reciprocating compressors, and the collection of fugitive emissions components located at well sites and gathering and boosting compressor stations. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly amend the 2016 NSPS OOOOa provisions associated with applications for use of an AMEL for methane work practice standards at well sites and gathering and boosting compressor stations and VOC and methane work practice standards at compressor stations in the transmission and storage segment.

The 2020 Technical Rule amended the AMEL application requirements to help streamline the process for evaluation and possible approval of advanced measurement technologies. The amendments included allowing submission of applications by, among others, owners and operators of affected facilities, manufacturers or vendors of leak detection technologies, or trade associations. The 2020 Technical Rule ''allows any person to submit an application for an AMEL under this provision.'' 85 FR 57422 (September 15, 2020). However, the 2020 Technical Rule, like the 2016 NSPS OOOOa still requires that the application include sufficient information to demonstrate that the AMEL achieves emission reductions at least equivalent to the work practice standards in the rule. To that end, the 2020 Technical Rule ''requires applications for these AMEL to include site-specific information to demonstrate equivalent emissions reductions, as well as site-specific procedures for ensuring continuous compliance.'' *Id.* At a minimum, the application should include field data that encompass seasonal variations, which may be supplemented with modeling analyses, test data, and/or other documentation. The specific work practice(s), including performance methods, quality assurance, the threshold that triggers action, and the mitigation thresholds are also required as part of the AMEL application. For example, for a technology designed to detect fugitive emissions, information such as the detection criteria that indicate fugitive emissions requiring repair, the time to complete repairs, and any methods used to verify successful repair would be required.

Since the 2020 Technical Rule changes to the AMEL provisions in the 2016 NSPS OOOOa are procedural in the sense that they mostly speak to the ''minimum information that must be included in each application in order for the EPA to make a determination of equivalency and, thus, be able to approve an alternative'' the EPA believes that it is appropriate to retain those amendments. 85 FR 57422 (September 15, 2020). If finalized, the application must demonstrate equivalence as explained above for both the reduction of methane and VOC emissions. Because the 2020 Technical Rule amended only the VOC standards in the 2016 NSPS OOOOa, and since EPA believes that basis for promulgation of this provision for AMEL applications equally applies to work practices standards for methane emissions at facilities in the production and processing segments and VOC and methane emissions at facilities in the transmission and storage segment, the EPA is proposing to apply these application requirements for all applicants seeking an AMEL for the methane and VOC work practice standards in NSPS OOOOa.

6. Alternative Fugitive Emissions Standards Based on Equivalent State Programs

The 2020 Technical Rule added a new section (at 40 CFR 60.5399a) which served two purposes. First, the new section outlined procedures for State, local, and Tribal authorities to seek the EPA's approval of their VOC fugitive emissions standards at well sites and gathering and boosting compressor stations as an alternative to the Federal standards. Second, the new section approved specific voluntary alternative standards for six States. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly allow this new section to apply to fugitive emissions standards for methane fugitive emissions at well sites and gathering and boosting compressor stations, and VOC and methane fugitive emissions at compressor stations in the transmission and storage segment.

The 2020 Technical Rule added this new section in part to allow the use of specific alternative fugitive emissions standards for VOC emissions for six State fugitive emissions programs that the EPA had concluded were at least equivalent to the fugitive emissions monitoring and repair requirements at 40 CFR 60.5397a(e), (f), (g), and (h) as amended in that rule.[187] These approved alternative fugitive emissions standards may be used for certain individual well sites or gathering and boosting compressor stations that are subject to VOC fugitive emissions monitoring and repair so long as the source complies with specified Federal requirements applicable to each approved alternative State program and included in 40 CFR 60.5399a(f) through (n). For example, a well site that is subject to the requirements of Pennsylvania General Permit 5A, section G, effective August 8, 2018, could choose to comply with those

[187] See memorandum, ''Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa,'' located at Docket ID No. EPA–HQ–OAR–2017–0483. January 17, 2020.

standards in lieu of the monitoring, repair, recordkeeping, and reporting requirements in the NSPS for fugitive emissions at well sites. However, in that example, the owner or operator must develop and maintain a fugitive emissions monitoring plan, as required in 40 CFR 60.5397a(c) and (d), and must monitor all of the fugitive emissions components, as defined in 40 CFR 60.5430a, regardless of the components that must be monitored under the alternative standard (*i.e.,* under Pennsylvania General Permit 5A, Section G in the example). Additionally, the facility choosing to use the EPA-approved alternative standard must submit, as an attachment to its annual report for NSPS OOOOa, the report that is submitted to its State in the format submitted to the State, or the information required in the report for NSPS OOOOa if the State report does not include site-level monitoring and repair information. If a well site is located in the State but is not subject to the State requirements for monitoring and repair (*i.e.,* not obligated to monitor or repair fugitive emissions), then the well site must continue to comply with the Federal requirements of the NSPS at 40 CFR 60.5397a in its entirety.

In addition to providing the EPA-approved voluntary alternative fugitive emissions standards for well sites and gathering and boosting compressor stations located in California, Colorado, Ohio, Pennsylvania, and Texas, and well sites in Utah, the amendments in the 2020 Technical Rule provide application requirements to request the EPA approval of an alternative fugitive emissions standards as State, local, and Tribal programs continue to develop. Applications for the EPA approval of alternative fugitive emissions standards based on State, local, or Tribal programs may be submitted by any interested person, including individuals, corporations, partnerships, associations, States, or municipalities. Similar to the application process for AMEL for advanced measurement technologies, the application must include sufficient information to demonstrate that the alternative fugitive emissions standards achieve emissions reductions at least equivalent to the fugitive emissions monitoring and repair requirements in the Federal NSPS. At a minimum, the application must include the monitoring instrument, monitoring procedures, monitoring frequency, definition of fugitive emissions requiring repair, repair requirements, recordkeeping, and reporting requirements. If any of the sections of the State regulations or permits approved as alternative fugitive emissions standards are changed at a later date, the State must follow the procedures outlined in 40 CFR 60.5399a to apply for a new evaluation of equivalency.

As part of the 2018 proposed rule (83 FR 52056, October 15, 2018) that resulted in the 2020 Technical Rule, the EPA evaluated the specific State programs for both methane and VOC emissions at well sites, gathering and boosting compressor stations, and compressor stations in the transmission and storage segment as discussed in detail in a memorandum to that docket evaluating the equivalency of State fugitive emissions programs.[188] The EPA is now proposing that all well sites and compressor stations located in and subject to the specified State regulations in 40 CFR 60.5399a may utilize these alternative fugitive emissions standards for both methane and VOC fugitive emissions. In the 2020 Technical Rule the EPA concluded that these monitoring, repair, recordkeeping, and reporting requirements were equivalent to the same types of requirements in the 2016 NSPS OOOOa for VOC at well sites and gathering and boosting compressor stations. See 85 FR 57424. The monitoring instrument (*i.e.,* OGI or EPA Method 21) will detect, at the same time, both methane and VOC emissions without speciating these emissions. Therefore, detection of one of these pollutants is also detection of the other pollutant. For the same reasons provided in the 2020 Technical Rule, and explained in the associated State equivalency memos, the EPA proposes to find these same State fugitive emissions standards (as specified in 40 CFR 60.5399a(f) through (n)) equivalent to the specified Federal methane fugitive emissions standards for well sites and gathering and boosting stations, and the methane and VOC fugitive emissions standards for compressor stations in the transmission and storage segment. The EPA is also proposing to allow State, local, and Tribal agencies to apply for the EPA approval of their fugitives monitoring program as an alternative to the Federal NSPS for methane. Put another way, the EPA is proposing to include methane throughout 40 CFR 60.5399a.

The EPA recognizes that the determinations of equivalence included in the 2020 Technical Rule were based on the fugitive emissions monitoring requirements that existed at that time for the 2016 NSPS OOOOa which, based on other changes in the 2020 Technical Rule, included an exemption from monitoring for low production well sites and required semiannual monitoring at gathering and boosting compressor stations. As explained above, the EPA is proposing to repeal both of those changes, and require semiannual monitoring at all well sites, including those with low production, and quarterly monitoring at gathering and boosting compressor stations. These proposed changes to the 2016 NSPS OOOOa fugitive emissions requirements do not impact the EPA's conclusion that the six previously approved alternative State programs are equivalent to the Federal standards. Even so, the EPA is proposing regulatory changes within the alternative State program provisions in 2016 NSPS OOOOa to account for these proposed changes to the Federal standards. See the redline version of regulatory text in the docket at Docket ID No. EPA–HQ–OAR–2021–0317. These changes are intended to ensure that the previously approved alternative State programs continue to maintain equivalency with the Federal standards if NSPS OOOOa is revised as proposed here. With these changes, the EPA continues to find that the alternative State programs that were previously approved are still equivalent with, if not better than, the Federal requirements.

7. Onshore Natural Gas Processing Plants

a. Capital Expenditure

The 2020 Technical Rule made certain amendments to the 2016 NSPS OOOOa definition of capital expenditure as it relates to modifications for VOC LDAR requirements at onshore natural gas processing plants. For the same reasons provided in the 2020 Technical Rule and reiterated below, the EPA is proposing to similarly amend this definition as it relates to the methane LDAR requirements at onshore natural gas processing plants.

The 2020 Technical Rule amended the definition of ''capital expenditure'' at 40 CFR 50.5430a by replacing the equation used to determine the percent of replacement cost, ''Y.'' This amendment was necessary because, as originally promulgated, the equation for determining ''Y'' would result in an error, thus, making it difficult to determine whether a capital expenditure had occurred using the NSPS OOOOa equation. The 2020 Technical Rule replaced the equation with an equation that utilizes the consumer price indices, ''CPI'' because it more appropriately reflects inflation than the original equation. Specifically, the equation for ''Y'' as amended in the

[188] See Docket ID Nos. EPA–HQ–OAR–2017–0483–0041 and EPA–HQ–OAR–2017–0483–2277.

2020 Technical Rule, is based on the CPI, where ''Y'' equals the CPI of the date of construction divided by the most recently available CPI of the date of the project, or ''CPI_N/CPI_{PD}.'' Further, the 2020 Technical Rule specifies that the ''annual average of the CPI for all urban consumers (CPI–U), U.S. city average, all items'' must be used for determining the CPI of the year of construction, and the ''CPI–U, U.S. city average, all items'' must be used for determining the CPI of the date of the project. This amendment clarified that the comparison of costs is between the original date of construction of the process unit (the affected facility) and the date of the project which adds equipment to the process unit. For these same reasons, the EPA is proposing that the definition of ''capital expenditure,'' as amended by the 2020 Technical Rule, also be used to determine whether modification had occurred and thus triggers the applicability of the methane LDAR requirements at onshore natural gas processing plants in the 2016 NSPS OOOOa.

b. Initial Compliance Period

The 2020 Technical Rule amended the VOC standards for onshore natural gas processing plants to specify that the initial compliance deadline for the equipment leak standards is 180 days. The EPA is proposing to apply this clarification to the initial compliance deadline with the methane standards for equipment leaks at onshore natural gas processing plants.

As explained in the 2020 Technical Rule, the EPA added a provision requiring compliance ''as soon as practicable, but no later than 180 days after initial startup'' because that provision was in the NSPS for equipment leaks of VOC at onshore natural gas processing plants when it was first promulgated, specifically at 40 CFR 60.632(a) of part 60, subpart KKK (NSPS KKK). 85 FR 57408. This provision at 40 CFR 60.632(a) provides up to 180 days to come into compliance with NSPS KKK. In 2012, the EPA revised the standards in NSPS KKK with the promulgation of NSPS OOOO [189] by lowering the leak definition for valves from 10,000 ppm to 500 ppm and requiring the monitoring of connectors. 77 FR 49490, 49498. While the EPA did not mention that it was also amending the 180-day compliance deadline in NSPS OOOO, this provision at 40 CFR 60.632(a) was not included in NSPS OOOO and, in turn, was not included in NSPS OOOOa. During the rulemaking for NSPS OOOOa, the EPA declined a request to include this provision at 40 CFR 60.632(a) in NSPS OOOOa, explaining that such inclusion was not necessary because NSPS OOOOa already includes by reference a similar provision (*i.e.,* 40 CFR 60.482–1a(a)) which requires each owner or operator to ''demonstrate compliance . . . within 180 days of initial startup,'' 80 FR 56593, 56647–8. However, in reassessing the issue during the rulemaking for the 2020 Technical Rule, the EPA noted that NSPS KKK includes both the provision in 40 CFR 60.632(a) and 40 CFR 60.482–1(a), which contains a provision that is the same as the one described above at 40 CFR 60.482–1a(a), thus suggesting that 40 CFR 60.632(a) is not redundant or unnecessary. In fact, the absence of this provision in NSPS OOOO/OOOOa raised a question as to whether compliance is required within 30 days for equipment that is required to be monitored monthly. To clarify this confusion and remain consistent with NSPS KKK, the 2020 Technical Rule amended NSPS OOOOa to reinstate this provision at 40 CFR 60.632(a). For the same reasons explained above, the EPA is proposing to similarly apply this provision to compliance with methane standards for the equipment leaks at onshore natural gas processing plants.

This provision clarifies that monitoring must begin as soon as practicable, but no later than 180 days after the initial startup of a new, modified, or reconstructed process unit at an onshore natural gas processing plant. Once started, monitoring must continue with the required schedule. For example, if pumps are monitored by month 3 of the initial startup period, then monthly monitoring is required from that point forward. This initial compliance period is different than the compliance requirements for newly added pumps and valves within a process unit that is already subject to a LDAR program. Initial monitoring for those newly added pumps and valves is required within 30 days of the startup of the pump or valve (*i.e.,* when the equipment is first in VOC service).

8. Technical Corrections and Clarifications

The 2020 Technical Rule also revised the 2016 NSPS OOOOa for VOC emissions to include certain additional technical corrections and clarifications. In this action, the EPA is proposing to apply these same technical corrections and clarifications to the methane standards for production and processing segments and/or the methane and VOC standards for the transmission and storage segment in the 2016 NSPS OOOOa, as appropriate. Specifically, the EPA is proposing to:

- Revise 40 CFR 60.5385a(a)(1), 60.5410a(c)(1), 60.5415a(c)(1), and 60.5420a(b)(4)(i) and (c)(3)(i) to clarify that hours or months of operation at reciprocating compressor facilities must be measured beginning with the date of initial startup, the effective date of the requirement (August 2, 2016), or the last rod packing replacement, whichever is latest.
- Revise 40 CFR 60.5393a(b)(3)(ii) to correctly cross-reference paragraph (b)(3)(i) of that section.
- Revise 40 CFR 60.5397a(c)(8) to clarify the calibration requirements when Method 21 of appendix A–7 to part 60 is used for fugitive emissions monitoring.
- Revise 40 CFR 60.5397a(d)(3) to correctly cross-reference paragraphs (g)(3) and (4) of that section.
- Revise 40 CFR 60.5401a(e) to remove the word ''routine'' to clarify that pumps in light liquid service, valves in gas/vapor service and light liquid service, and pressure relief devices (PRDs) in gas/vapor service within a process unit at an onshore natural gas processing plant located on the Alaska North Slope are not subject to any monitoring requirements, whether the monitoring is routine or nonroutine.
- Revise 40 CFR 60.5410a(e) to correctly reference pneumatic pump affected facilities located at a well site as opposed to pneumatic pump affected facilities not located at a natural gas processing plant (which would include those not at a well site). This correction reflects that the 2016 NSPS OOOOa do not contain standards for pneumatic pumps at gathering and boosting compressor stations. 81 FR 35850.
- Revise 40 CFR 60.5411a(a)(1) to remove the reference to paragraphs (a) and (c) of 40 CFR 60.5412a for reciprocating compressor affected facilities.
- Revise 40 CFR 60.5411a(d)(1) to remove the reference to storage vessels, as this paragraph applies to all the sources listed in 40 CFR 60.5411a(d), not only storage vessels.
- Revise 40 CFR 60.5412a(a)(1) and (d)(1)(iv) to clarify that all boilers and process heaters used as control devices on centrifugal compressors and storage vessels must introduce the vent stream into the flame zone. Additionally, revise 40 CFR 60.5412a(a)(1)(iv) and (d)(1)(iv)(D) to clarify that the vent stream must be introduced with the primary fuel or as the primary fuel to

[189] ''Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for Which Construction, Modification or Reconstruction Commenced After August 23, 2011, and on or before September 18, 2015.''

meet the performance requirement option. This is consistent with the performance testing exemption in 40 CFR 60.5413a and continuous monitoring exemption in 40 CFR 60.5417a for boilers and process heaters that introduce the vent stream with the primary fuel or as the primary fuel.

- Revise 40 CFR 60.5412a(c) to correctly reference both paragraphs (c)(1) and (2) of that section, for managing carbon in a carbon adsorption system.
- Revise 40 CFR 60.5413a(d)(5)(i) to reference fused silica-coated stainless steel evacuated canisters instead of a specific name brand product.
- Revise 40 CFR 60.5413a(d)(9)(iii) to clarify the basis for the total hydrocarbon span for the alternative range is propane, just as the basis for the recommended total hydrocarbon span is propane.
- Revise 40 CFR 60.5413a(d)(12) to clarify that all data elements must be submitted for each test run.
- Revise 40 CFR 60.5415a(b)(3) to reference all applicable reporting and recordkeeping requirements.
- Revise 40 CFR 60.5416a(a)(4) to correctly cross-reference 40 CFR 60.5411a(a)(3)(ii).
- Revise 40 CFR 60.5417a(a) to clarify requirements for controls not specifically listed in paragraph (d) of that section.
- Revise 40 CFR 60.5422a(b) to correctly cross-reference 40 CFR 60.487a(b)(1) through (3) and (b)(5).
- Revise 40 CFR 60.5422a(c) to correctly cross-reference 40 CFR 60.487a(c)(2)(i) through (iv) and (c)(2)(vii) through (viii).
- Revise 40 CFR 60.5423a(b) to simplify the reporting language and clarify what data are required in the report of excess emissions for sweetening unit affected facilities.
- Revise 40 CFR 60.5430a to remove the phrase ''including but not limited to'' from the ''fugitive emissions component'' definition. During the 2016 NSPS OOOOa rulemaking, the EPA stated in a response to comment that this phrase is being removed,[190] but did not do so in that rulemaking.
- Revise 40 CFR 60.5430a to remove the phrase ''at the sales meter'' from the ''low pressure well'' definition to clarify that when determining the low-pressure status of a well, pressure is measured within the flow line, rather than at the sales meter.
- Revise Table 3 of 40 CFR part 60, subpart OOOOa, to correctly indicate that the performance tests in 40 CFR 60.8 do not apply to pneumatic pump affected facilities.
- Revise Table 3 of 40 CFR part 60, subpart OOOOa, to include the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station in the list of exclusions for notification of reconstruction.
- Revise 40 CFR 60.5393a(f), 60.5410a(e)(8), 60.5411a(e), 60.5415a(b) introductory text and (b)(4), 60.5416a(d), and 60.5420a(b) introductory text and (b)(13), and introductory text in 40 CFR 60.5411a and 60.5416a, to remove language associated with the administrative stay we issued under section 307(d)(7)(B) of the CAA in ''Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay'' (82 FR 25730, June 5, 2017). The administrative stay was vacated by the D.C. Circuit on July 3, 2017.

XI. Summary of Proposed NSPS OOOOb and EG OOOOc

This section presents a summary of the specific NSPS standards and EG presumptive standards the EPA is proposing for various types of equipment and emission points. More details of the rationale for these standards and requirements, including alternative compliance options and exemptions to the standards, are provided in section XII of this preamble and the TSD for this action in the public docket. As stated in section I, the EPA intends to provide draft regulatory text for the proposed NSPS OOOOb and EG OOOOc in a supplemental proposal.

A. Fugitive Emissions From Well Sites and Compressor Stations

Fugitive emissions are unintended emissions that can occur from a range of equipment at any time. The magnitude of these emissions can also vary widely. The EPA has historically targeted fugitive emissions from the Crude Oil and Natural Gas source category through ground-based component level monitoring using OGI, or alternatively, EPA Method 21.

The EPA is proposing the following monitoring requirements and presumptive standards for the collection of fugitive emissions components located at well sites and compressor stations. Additional details for the proposed standards and proposed presumptive standards are included in the following subsections. Information received through the various solicitations in this section may be used to evaluate if a change in the BSER is appropriate from the proposed requirements below, specifically consideration of alternative measurement technologies as the BSER. Any potential changes would be addressed through a supplemental proposal.

- Well sites with total site-level baseline methane emissions less than 3 tpy: Demonstration, based on a site-specific survey, that actual emissions are reflected in the baseline methane emissions calculation,
- Well sites with total site-level baseline methane emissions of 3 tpy or greater: Quarterly OGI or EPA Method 21 monitoring,
- (Co-proposal) Well sites with total site-level baseline methane emissions of 3 tpy or greater and less than 8 tpy: Semiannual OGI or EPA Method 21 monitoring,
- (Co-proposal) Well sites with total site-level baseline methane emissions of 8 tpy or greater: Quarterly OGI or EPA Method 21 monitoring,
- Compressor stations: Quarterly OGI or EPA Method 21 monitoring,
- Well sites and compressor stations located on the Alaska North Slope: Annual monitoring, with separate initial monitoring requirements, and
- Alternative screening approach for all well sites and compressor stations: Bimonthly screening surveys using advanced measurement technology and annual OGI or EPA Method 21 monitoring at each individual well site or compressor station.

1. Definition of Fugitive Emissions Component

A key factor in evaluating how to target fugitive emissions is clearly identifying the emissions of concern and the sources of those emissions. In the 2016 NSPS OOOOa, the EPA defined ''fugitive emissions component'' as ''any component with the potential to emit methane and VOCs'' and included several specific component types, ranging from valves and connectors, to openings on controlled storage vessels that were not regulated under NSPS OOOOa.

However, data shows that the universe of components with potential for fugitive emissions is broader than the illustrative list included in the 2016 NSPS OOOOa, and that the majority of the largest emissions events occur from a subset of components that may not have been clearly included in the definition. Therefore, the EPA is proposing a new definition for ''fugitive emissions component'' to provide clarity that these sources of large emission events are covered.

[190] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7632, Chapter 4, page 4–319.

''Fugitive emissions component'' is proposed to be any component that has the potential to emit fugitive emissions of methane and VOC at a well site or compressor station, including valves, connectors, PRDs, open-ended lines, flanges, all covers and closed vent systems, all thief hatches or other openings on a controlled storage vessel, compressors, instruments, meters, natural gas-driven pneumatic controllers or natural gas-driven pumps. However, natural gas discharged from natural gas-driven pneumatic controllers or natural gas-driven pumps are not considered fugitive emissions if the device is operating properly and in accordance with manufacturers specifications. Control devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any Federal rule, State rule, or permit, are also considered fugitive emissions components. This proposed definition includes the same components that were included in the 2016 NSPS OOOOa and adds sources of large emissions, such as malfunctioning controllers or control devices.

The inclusion of specific component types in this proposed definition would allow the use of OGI, EPA Method 21, or an alternative screening technology to identify emissions that would either be repaired (*i.e.,* leaks) or have a root cause analysis with corrective action (*e.g.,* malfunctioning control device, unintentional gas carry through, venting from covers and openings on a controlled storage vessel, or malfunctioning natural gas-driven pneumatic controllers). Further, we are proposing that where a CVS is used to route emissions from an affected facility (*i.e.,* centrifugal or reciprocating compressor, pneumatic pump, or storage vessel), the owner or operator would demonstrate there are no detectable emissions from the covers and CVS through the OGI (or EPA Method 21) monitoring conducted during the fugitive emissions survey. Where emissions are detected, corrective actions to complete all necessary repairs as soon as practicable would be required, and the emissions would be considered a potential violation of the no detectable emissions standard. In the case of a malfunction or operational upset of a control device or the equipment itself, where emissions are not expected to occur if the equipment is operating in compliance with the standards of the rule, this proposal would require the owner or operator to conduct a root cause analysis to determine why the emissions are present, take corrective action to complete all necessary repairs as soon as practicable and prevent reoccurrence of emissions, and report the malfunction or operational upset as a potential violation of the underlying standards for the source of the emissions. We are soliciting comment on whether to include the option to continue utilizing monthly AVO surveys as demonstrations of no detectable emissions from a CVS but are not proposing that option specifically. Because the EPA is proposing both NSPS and EG in this action, we anticipate that CVS associated with controlled pneumatic pumps will be located at well sites subject to fugitive emissions monitoring. Therefore, we do not believe the monthly AVO option is necessary. However, we are soliciting comment on whether there are circumstances where a CVS associated with a controlled pneumatic pump is located at a well site not otherwise subject to fugitive emissions monitoring and where OGI (or EPA Method 21) would be an additional burden.

The EPA is soliciting comment on this proposed definition of ''fugitive emissions component,'' including any additional components or characterization of components that should be included. Further, we are soliciting comment on the use of the fugitive emissions survey to identify malfunctions and other large emission sources where the equipment is not operating in compliance with the underlying standards, including the proposed requirement to perform a root cause analysis and to take corrective action to mitigate and prevent future malfunctions.

2. Fugitive Emissions From Well Sites

The current NSPS for reducing fugitive VOC and methane emissions at well sites requires semiannual monitoring, except that a low production well site (one that produces at or below 15 barrels of oil equivalent (boe) per day) is exempt from VOC monitoring. As explained in section X.A.1, we are proposing to remove that exemption from NSPS OOOOa, as we have concluded that exemption was not justified by the underlying record and does not represent BSER. Further, based on our revised BSER analysis, which is summarized in section XII.A.1.a, the EPA is proposing updated standards for reducing fugitive VOC and methane emissions from the collection of fugitive emissions components located at new, modified, or reconstructed well sites (under the newly proposed NSPS OOOOb). Also, for the reasons discussed in section XII.A.2, the EPA is proposing to determine that the BSER analysis supports a presumptive standard for reducing methane emissions from the collection of fugitive emissions components located at existing well sites (under the newly proposed EG OOOOc) that is the same as what we are proposing for the NSPS (for NSPS OOOOb). Provided below is a summary of the proposed updated NSPS and the proposed EG.

a. NSPS OOOOb

For new, modified, or reconstructed sources, we are proposing a fugitive emissions monitoring and repair program that includes monitoring for fugitive emissions with OGI in accordance with the proposed 40 CFR part 60, appendix K (''appendix K''), which is included in this action and outlines the proposed procedures that must be followed to identify emissions using OGI.[191] We are also proposing that EPA Method 21 may be used as an alternative to OGI monitoring. We are further proposing that monitoring must begin within 90 days of startup of production (or startup of production after modification).

Unlike in NSPS OOOOa which, as amended by the 2020 Technical Rule, set VOC monitoring frequency based on production level, the EPA is proposing that the OGI monitoring frequency be based on the site-level methane baseline emissions,[192] as determined, in part, through equipment/component count emission factors. The EPA is proposing the calculation of the total site-wide methane emissions, including fugitive emissions from components, emissions from natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, storage vessels, as well as other regulated and non-regulated emission sources. Specifically, we are proposing that owners or operators would calculate the site-level baseline methane emissions using a combination of population-based emission factors and storage vessel emissions. Further, the EPA proposes this calculation would be repeated every time equipment is added to or removed from the site. For each natural gas-driven pneumatic pump, continuous bleed natural gas-driven pneumatic

[191] ''Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging'' located at Docket ID No. EPA–HQ–OAR–2021–0317.

[192] As shown in the TSD, the EPA analyzed the monitoring frequency for both methane and VOC under both the single pollutant approach and the multipollutant approach. Because the composition of gas at a well site is predominantly methane (approximately 70 percent), a methane threshold represents the lowest threshold that is cost effective to control both VOC and methane emissions.

controller, and intermittent bleed natural gas-driven pneumatic controller located at the well site, the owner or operator would apply the population emission factors for all components found in Table W–1A of GHGRP subpart W. For each piece of major production and processing equipment and each wellhead located at the well site, the owner or operator would first apply the default average component counts for major equipment found in Table W–1B and Table W–1C of GHGRP subpart W, and then apply the component-type emission factors for the population of valves, connectors, open-ended lines, and PRVs found in Table 2–8 of the 1995 Emissions Protocol.[193] Finally, the owner or operator would use the calculated potential methane emissions after applying control (if applicable) for each storage vessel tank battery located at the well site. The sum of the emissions estimated for all equipment at the site would be used as the baseline methane emissions for determining the applicable monitoring frequency. The EPA proposes to use the default population emission factors found in Table W–1A of GHGRP subpart W and the default average component counts for major equipment found in Tables W–1B and W–1C of GHGRP subpart W because they are well-vetted emission and activity factors used by the Agency. The EPA is not incorporating these emission factors directly into the proposed NSPS OOOOb or EG OOOOc because they could be the subject of future GHGRP subpart W revisions, and if revised, those revisions would be relevant to this calculation. For the individual components (*e.g.,* valves and connectors), the EPA proposes to rely on the component-type emission factors found in Table 2–8 of the 1995 Emissions Protocol for purposes of quantifying emissions from major production and processing equipment and each wellhead located at the well site because these data have been relied upon in previous rulemakings for this sector, have been the subject of extensive public comment, and the EPA has determined that they are appropriate to use for purposes of this action.

The EPA requests comment on whether the proposed methodologies for calculating site-level baseline methane emissions are appropriate for these emission sources, and if not, what methodologies would be more appropriate. Specifically, the EPA recognizes the proposed calculation methodology assumes all equipment is operating as designed (*e.g.,* controlled storage vessels with all vapors routed to a control that is actually achieving 95 percent reduction or greater). Therefore, we are soliciting comment on whether sites should use the uncontrolled PTE calculation for their storage vessels in their site-level baseline estimate to account for times when these vessels are not operating as designed, which is a known cause of large emission events of concern. Further, to that point, the EPA is soliciting comment on how to develop a factor that could be applied to the site-level baseline calculation that would account for large emission events, or any specific data that would provide a factor for these events. As we state throughout this preamble, large emission events are of specific concern and fugitive emissions monitoring is an effective tool for detecting these emissions, therefore, we acknowledge there is considerable interest from various stakeholders that these emission events are accounted for in our analyses. At this time, the EPA does not have enough information to develop a factor or determine how to best apply that factor. Information provided through this solicitation would allow us to consider additional revisions to this calculation methodology through a supplemental proposal.

The EPA is also soliciting comment on whether providing direct major equipment population emission factors that can be combined with site-specific gas compositions would provide a more transparent and less burdensome means to develop the site-specific emissions estimates than using a combination of major equipment counts, specific component counts per major equipment, and component-level population emission factors. Furthermore, the EPA requests comment on whether site-level baseline methane emissions should be determined using a baseline emissions survey instead of the proposed methodology, and if so, what methodologies should be used to quantify emissions from the survey such as measurement or emission factors based on leaking component emission factors. The EPA also solicits comment on specific methodologies to support commenters' positions. The EPA also requests comment on whether there are additional production and processing equipment or emission sources that should be included in the site-level baseline methane emissions. For example, the EPA is aware that there could be emission sources such as engines, dehydrator venting, compressor venting, associated gas venting, and migration of gas outside of the wellbore at a well site. If such equipment or emission sources should be included in the site-level baseline, the EPA requests comment on methodologies for quantifying emissions for purposes of the baseline.

Based on the analysis described in section XII.A.1, the potential for fugitive emissions is impacted more by the number and type of equipment at the site, and not by the volume of production. Therefore, the EPA believes it is more appropriate to use site-specific emissions estimates based on the number and type of equipment located at the individual site to determine the monitoring frequency. Table 13 summarizes the proposed site-level baseline methane thresholds for the proposed monitoring frequencies, which according to our analysis would achieve the greatest cost-effective emission reductions.

As noted below, the EPA solicits comment on all aspects of the proposed tiered approach to monitoring that is summarized in Table 13. Although we are proposing no routine OGI monitoring where site-level baseline methane emissions are below 3 tpy, the EPA is proposing to require these sites to demonstrate the actual emissions are accounted for in the calculation. This demonstration would include a survey, such as OGI, EPA Method 21 (including provisions for the use of a soap solution), or advanced measurement technologies. Given that this demonstration is designed to show actual emissions are below 3 tpy, and most survey techniques are not quantitative, the EPA anticipates that sources finding emissions will make repairs on equipment/components identified as leaking during the demonstration survey.

The EPA acknowledges that the 2016 NSPS OOOOa and this proposal allow the use of EPA Method 21 as an alternative to OGI monitoring to detect fugitive emissions from the collection of fugitive emissions components under the proposed tiered approach to monitoring. However, as discussed in section XI.A.5, EPA Method 21 is not proposed as an alternative for follow-up OGI surveys under the proposed alternative screening approach using advanced measurement technologies when screening detects emissions. This is because EPA Method 21 is not able to find all sources of leaks and is therefore not an appropriate method for detection in these cases where large emissions events have been identified. Given this limitation, the EPA is soliciting comment on whether EPA Method 21 remains an appropriate

[193] EPA, Protocol for Equipment Leak Emission Estimates, EPA–453/R–95–017, November 1995.

alternative to OGI for routine OGI surveys.

TABLE 13—PROPOSED WELL SITE MONITORING FREQUENCIES BASED ON SITE–LEVEL BASELINE METHANE EMISSIONS

Site-level baseline methane emissions threshold	Proposed OGI monitoring frequency	Co-proposed OGI monitoring frequency
>0 and <3 tpy	No routine monitoring required	No routine monitoring required.
≥3 and <8 tpy	Quarterly	Semiannual.
≥8 tpy	Quarterly	Quarterly.

Where quarterly monitoring is proposed, subsequent quarterly monitoring would occur at least 60 days apart. Where semiannual monitoring is co-proposed, subsequent semiannual monitoring would occur at least 4 months apart and no more than 7 months apart. We are proposing to retain the provision in the 2016 NSPS OOOOa that the quarterly monitoring may be waived when temperatures are below 0 °F for two of three consecutive calendar months of a quarterly monitoring period.

The EPA has previously required the use of OGI technology to detect fugitive emissions of methane and VOC from the oil and gas sector (*i.e.,* well sites and compressor stations). However, the EPA had not developed a protocol for its use even though the EPA has previously mentioned the need for an OGI protocol during other rulemakings where OGI has been proposed for leak detection.[194] In this document, the EPA is proposing a draft protocol for the use of OGI as appendix K to 40 CFR part 60. The EPA notes that while this protocol is being proposed for use in the oil and gas sector, the applicability of the protocol is broader. The protocol is applicable to surveys of process equipment using OGI cameras in the entire oil and gas upstream and downstream sectors from production to refining to distribution where a subpart in those sectors references its use.

As part of the development of appendix K, the EPA conducted an extensive literature review on the technology development as well as observations on current application of OGI technology. Approximately 150 references identify the technology, applications, and limitations of OGI. The EPA also commissioned multiple laboratory studies and OGI technology evaluations. Additionally, on November 9 and 10, 2020, the EPA held a virtual stakeholder workshop to gather input on development of a protocol for the use of OGI. The information obtained from these efforts was used to develop the TSD for appendix K, which provides technical analyses, experimental results, and other supplemental information used to evaluate and develop standardized procedures for the use of OGI technology in monitoring for fugitive emissions of VOCs, HAP, and methane from industrial environments.[195]

Appendix K outlines the proposed procedures that instrument operators must follow to identify leaks or fugitive emissions using a hand-held, field portable infrared camera. Additionally, appendix K contains proposed specifications relating to the required performance of qualifying infrared cameras, required operator training and verification, determination of an operating window for performing surveys, and requirements for a monitoring plan and recordkeeping. The EPA is requesting comment on all aspects of the draft OGI protocol being proposed as appendix K to 40 CFR part 60.[196]

As mentioned in section X.B.4.f, we are proposing that, once fugitive methane emissions are detected during the OGI survey, a first attempt at repair must be made within 30 days of detecting the fugitive emissions, with final repair, including resurvey to verify repair, completed within 30 days after the first attempt. These proposed repair requirements with respect to methane fugitive emissions are the same as those made in the 2020 Technical Rule for VOC fugitive emissions (and proposed in section X.B.4.f for methane in this action). Because large emission events contribute disproportionately to emissions, the EPA is soliciting comment on how to structure a requirement that would tier repair deadlines based on the severity of the fugitive emissions identified during the OGI (or EPA Method 21) surveys. In order for such a structure to work, there would need to be a way to qualify which fugitive emissions are smaller and which are larger, as the initial monitoring with OGI will not provide this information. One approach could be to define broad categories of leaks and make assumptions about the magnitude of emissions for those broad categories. For example, an open thief hatch would be considered a very large leak due to the surface opening size, and it would need to be remedied on the tightest timeframe, whereas a leaking connector would be considered a small leak based on historical emissions factors and could be repaired on a more lenient timeframe. The EPA is soliciting comments on how this approach could be structured, particularly the types of leaks that would fall into each broad category and the appropriate repair timeframes for each of the categories. The EPA is also soliciting comment on other approaches that could also be implemented for repairing fugitive emissions in a tiered structure. Finally, we are proposing to retain the requirement for owners and operators to develop a fugitive emissions monitoring plan that covers all the applicable requirements for the collection of fugitive emissions components located at a well site and includes the elements specified in the proposed appendix K when using OGI.

The affected facilities include well sites with major production and processing equipment, and centralized tank batteries. As in the 2020 Technical Rule, the EPA is proposing to not include ''wellhead only well sites,'' as affected facilities when the well site is a wellhead only well site at the date it becomes subject to the rule. Based on the proposed site-level baseline methane emissions calculation methodology, wellhead only sites would only calculate emissions from fugitive components (*e.g.,* valves, connectors, flanges, and open-ended lines) that are located on the wellhead. We believe

[194] The development of appendix K to 40 CFR part 60 was previously mentioned in both the proposal for the National Uniform Emission Standards for Storage Vessel and Transfer Operations, Equipment Leaks, and Closed Vent Systems and Control Devices; and Revisions to the National Uniform Emission Standards General Provisions (77 FR 17897, March 26, 2012) and the Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards (79 FR 36880, June 30, 2014).

[195] *Technical Support Document—Optical Gas Imaging Protocol (40 CFR part 60, Appendix K),* available in the docket for this action.

[196] See appendix K in Docket ID No. EPA–HQ–OAR–2021–0317.

these sites would not exceed the 3 tpy threshold to require routine monitoring. However, unlike the 2020 Technical Rule, the EPA is proposing that when a well site later removes all major production and processing equipment such that it becomes a wellhead only well site, it must recalculate the emissions in order to determine if a different frequency is then required. In this proposal, the definitions for ''wellhead only well site'' and ''well site'' would be the same as those finalized in the 2020 Technical Rule. Specifically, ''wellhead only well site'' means ''for purposes of the fugitive emissions standards, a well site that contains one or more wellheads and no major production and processing equipment.'' The term ''major production and processing equipment'' refers to ''reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water.'' The EPA is soliciting comment on whether any other equipment not included in this definition should be added in order to clearly specify what well sites are considered wellhead only sites. Specifically, the EPA is soliciting comment on the inclusion of natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, and pumpjack engines in the definition of ''major production and processing equipment.'' A ''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, a well site includes a centralized production facility. Also, for purposes of the fugitive emissions standards, a well site does not include: (1) UIC Class II oilfield disposal wells and disposal facilities; (2) UIC Class I oilfield disposal wells; and (3) the flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

In addition to retaining the above definitions, the EPA is also proposing a new definition for ''centralized production facility'' for purposes of fugitive emissions requirements for well sites, where a ''centralized tank battery'' is one or more permanent storage tanks and all equipment at a single stationary source used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations. Additional discussion on centralized production facilities is included in section XI.L.

The EPA is not proposing any change to the current definition of modification as it relates to fugitive emissions requirements at well sites or centralized production facilities. Specifically, modification occurs at a well site when: (1) A new well is drilled at an existing well site; (2) a well at an existing well site is hydraulically fractured; or (3) a well at an existing well site is hydraulically refractured. Similarly, modification occurs at a centralized production facility when (1) any of the actions above occur at an existing centralized production facility; (2) a well sending production to an existing centralized production facility is modified as defined above for well sites; or (3) a well site subject to the fugitive emissions standards for new sources removes all major production and processing equipment such that it becomes a wellhead only well site and sends production to an existing centralized production facility.

b. EG OOOOc

For existing well sites (for EG OOOOc), we are proposing a presumptive standard that follows the same fugitive monitoring and repair program as for new sources. For the reasons discussed in section XII.A.2, the BSER analysis for existing sources supports proposing a presumptive standard for reducing methane emissions from the collection of fugitive emissions components located at existing well sites that is the same as what the EPA is proposing for new, reconstructed, or modified sources (for NSPS OOOOb). The EPA did not identify any factors specific to existing sources that would alter the analysis performed for new sources to make that analysis different for existing well sites. The EPA determined that the OGI technology, methane emission reductions, costs, and cost effectiveness discussed above for the collection of fugitive emissions components at new well sites are also applicable for the collection of fugitive emissions components at existing well sites. Further, the fugitive emissions requirements do not require the installation of controls on existing equipment or the retrofit of equipment, which can generally be an additional factor for consideration when determining the BSER for existing sources. Therefore, the EPA found is appropriate to use the analysis developed for the proposed NSPS OOOOb to also develop the BSER and proposed presumptive standards for the EG OOOOc.

Based on the information available at this time, the EPA thinks the large number of existing well sites, many of which are not complex warrants soliciting comment on whether existing well sites (or a subcategory thereof) could have different emission profiles due to certain site characteristics or other factors that would suggest a different presumptive standard is appropriate. Further, we remain concerned about the burden of fugitive emissions monitoring requirements on small businesses. Therefore, we are requesting comment on regulatory alternatives for well sites that accomplish the stated objectives of the CAA and which minimize any significant economic impact of the proposed rule on small entities, including any information or data that pertain to the emissions impacts and costs of our proposal to remove the exemption from fugitive monitoring for well sites with low emissions, or would support alternative fugitive monitoring requirements for these sites. We are soliciting data that assess the emissions from low production well sites, and information on any factors that could make certain well sites less likely to emit VOC and methane, including geologic features, equipment onsite, production levels, and any other factors that could establish the basis for appropriate regulatory alternatives for these sites. Further, the EPA is aware there are a subset of existing well sites that are owned by individual homeowners, farmers, or companies with very few employees (well below the threshold defining a small business). For these owners, the EPA is concerned our analysis underestimates the actual burden imposed by these proposed standards. As an example, ownership may be limited to 1 or 2 wells located on an individual's property, for which the production is used for heating the home. The cost burden of conducting fugitive emissions surveys in this type of scenario has not fully be analyzed. Therefore, the EPA solicits comment and information that would allow us to

further evaluate the burden on the smallest companies to further propose appropriate standards at this subset (or other similar subsets) of well sites through a supplemental proposal.

Finally, we are soliciting comment on all aspects of the proposed fugitive emissions requirements for both new and existing well sites, including whether we should use the tiering approach, whether the tiers we have defined are appropriate, and the monitoring requirements for each tier, including whether it would be cost-effective to monitor at more frequent intervals than proposed. The EPA may include revisions to this proposal for ground-based OGI monitoring at well sites if information is received that would warrant consideration of a different approach to establishing monitoring frequencies at well sites.

3. Fugitive Emissions from Compressor Stations

The current NSPS for reducing fugitive emissions from the collection of fugitive emissions components located at a compressor station is a fugitive emissions monitoring and repair program requiring quarterly OGI monitoring.[197] Based on our analysis, which is summarized in section XII.A.1.b, the EPA is proposing quarterly OGI monitoring requirement for both methane and VOC as it continues to reflect the BSER for reducing both emissions from fugitive components at new, modified, and reconstructed compressor stations. Likewise, the EPA is also proposing quarterly monitoring as a presumptive GHG standard (in the form of limitation on methane emissions) for the collection of fugitive emissions components located at existing compressor stations. The affected compressor stations include gathering and boosting, transmission, and storage compressor stations.

a. NSPS OOOOb

We are proposing that the quarterly monitoring using OGI be conducted in accordance with the proposed appendix K described above in section XI.A.2, which outlines procedures that must be followed to identify leaks using OGI. We are proposing to retain the current requirements that monitoring must begin within 90 days of startup of the station (or startup after modification), with subsequent quarterly monitoring occurring at least 60 days apart. Also, quarterly monitoring may be waived when temperatures are below 0 °F for two of three consecutive calendar months of a quarterly monitoring period. We are also not proposing any change to the following repair-related requirements: Specifically, a first attempt at repair must be made within 30 days of detecting the fugitive emissions, with final repair, including resurvey to verify repair, completed within 30 days after the first attempt. In addition, owners and operators must develop a fugitive emissions monitoring plan that covers all the applicable requirements for the collection of fugitive emissions components located at a compressor station. In conjunction with the proposed requirement that monitoring be conducted in accordance with the proposed appendix K, we are proposing to require that the monitoring plan also include elements specified in the proposed appendix K when using OGI.

b. EG OOOOc

For existing sources, we are proposing a presumptive standard that includes the same fugitive emissions monitoring and repair program as for new sources. For the reasons discussed in section XII.A.2, the BSER analysis for existing sources supports proposing a presumptive standard for reducing methane emissions from the collection of fugitive emissions components located at existing compressor stations that is the same as what the EPA is proposing for new, modified, or reconstructed sources (for NSPS OOOOb).

Similar to well sites, we are soliciting comment on all aspects of the proposed quarterly monitoring for both new and existing compressor stations, including whether more frequent monitoring would be appropriate. We are also soliciting information on several additional topics. First, the EPA is soliciting comment and data to assess whether compressor stations should be subcategorized for the NSPS and/or the EG, which the EPA could consider through a supplemental proposal. For example, some industry stakeholders have asserted that station throughput directly correlates to the operating pressures, equipment counts, and condensate production, which would influence fugitive emissions at the station. They suggested that subcategorization based on design throughput capacity for the compressor station may be appropriate. We are specifically seeking information related to throughputs where fugitive emissions of methane are demonstrated to be minimal below a certain capacity. While this specific example was raised in the context of existing sources only, the EPA is also soliciting comment on whether new, modified, or reconstructed compressor stations could encounter the same issue and therefore warrant similar subcategorization.

Next, for compressor stations, we are soliciting comment on delayed repairs by existing sources when parts are not readily available and must be special ordered. In comments submitted to the EPA as part of the stakeholder outreach conducted prior to this proposal, industry stakeholders stated that the EPA ''should acknowledge that existing sources are older pieces of equipment so there is a higher likelihood that replacement parts will not be readily available; therefore, a lack of available parts should be an appropriate cause to delay a repair.'' [198] Industry stakeholders further explained that operators will need to special order replacement parts. Further, they stated in their comments that operators should be afforded 30 days to schedule the repair once they have received the replacement part. The EPA is soliciting comment and data to better understand the breadth of this issue with replacement parts for existing compressor stations. Additionally, we are soliciting comment on whether 30 days following receipt of the replacement part is appropriate for completing delayed repairs at existing compressor stations, whether there should be any limit on delays in repairs under these circumstances, and whether this compliance flexibility should be limited or disallowed based on the severity of the leak to be repaired.

We are also soliciting comment on the specific records that should be maintained and/or reported to justify delayed repairs as a result of part availability issues. Depending on the additional information received, the EPA may consider proposing changes to the proposed EG for compressor stations through a supplemental proposal.

Finally, as discussed in section XI.A.2, the EPA is soliciting comment on whether the scheduling of repairs at compressor stations should be tiered based on severity of the emissions found. Please refer to section XI.A.3 for additional details on this solicitation for comment.

4. Well Sites and Compressor Stations on the Alaska North Slope

For new, reconstructed, and modified well sites and compressor stations

[197] Note that for gathering and boosting compressor stations, the EPA is proposing to rescind the 2020 Technical Rule amendment that changed the monitoring frequency to semiannual for VOC emissions. See section X.A.2 for more information.

[198] Document ID No. EPA–HQ–OAR–2021–0295–0033.

located on the Alaska North Slope, based on the rationale provided in section X.B.4.c of this preamble, the EPA is proposing the same monitoring requirements as those in NSPS OOOOa (under newly proposed OOOOb). Also, the EPA is proposing to determine that the same technical infeasibility issues with weather conditions exist for existing well sites and compressor stations located on the Alaska North Slope. Therefore, the EPA is proposing a presumptive standard for reducing methane emissions from the collection of fugitive emissions components located at existing well sites and compressor stations located on the Alaska North Slope (under the newly proposed EG OOOOc) that is the same as what we are proposing for NSPS OOOOb.

Specifically, the EPA is proposing to require annual monitoring of methane and VOC emissions at all well sites and compressor stations located on the Alaska North Slope, with subsequent annual monitoring at least 9 months apart but no more than 13 months apart. The EPA is also proposing to require that new, reconstructed, and modified well sites and compressor stations located on the Alaska North Slope that startup (initially, or after reconstruction or modification) between September and March to conduct initial monitoring of methane and VOC fugitive emissions within 6 months of startup, or by June 30, whichever is later. Finally, the EPA is proposing to require that new, reconstructed, and modified well sites and compressor stations located on the Alaska North Slope that startup (initially, or after reconstruction or modification) between April and August to conduct initial monitoring of methane and VOC fugitive emissions within 90 days of startup.

5. Alternative Screening Using Advanced Measurement Technologies

For new, modified, or reconstructed sources (*i.e.,* collection of fugitive emissions components located at well sites and compressor stations), the EPA is proposing an alternative fugitive emissions monitoring and repair program that includes bimonthly screening for large emission events using advanced measurement technologies followed with at least annual OGI in accordance with the proposed 40 CFR part 60, appendix K (''appendix K''), which is included in this action and outlines the proposed procedures that must be followed to identify emissions using OGI.[199] Additionally, we are proposing this same alternative screening using advanced measurement technologies as an alternative presumptive standard for existing sources.

Specifically, the EPA is proposing to allow owners and operators the option to comply with this alternative fugitive emissions standard instead of the proposed ground based OGI surveys summarized in sections XI.A.2 and XI.A.3. The EPA proposes to require owners and operators choosing this alternative standard to do so for all affected well sites and compressor stations within a company-defined area. This company-defined area could be a county, sub-basin, or other appropriate geographic area. Under this proposed alternative, the EPA proposes to require a screening survey on a bimonthly basis using a methane detection technology that has been demonstrated to achieve a minimum detection threshold of 10 kg/hr. This screening survey would be used to identify individual sites (*i.e.,* well sites and compressor stations) where a follow-up ground-based OGI survey of all fugitive emissions components at the site is needed because fugitive emissions have been detected. Given the proposed minimum detection threshold of 10 kg/hr, which would constitute a significant emissions event, the EPA believes this follow-up OGI survey should be completed in an expeditious timeframe, therefore we are proposing to require this follow-up OGI survey of all fugitive emissions components at the site within 14 days of the screening survey. However, additional information is needed to fully evaluate the appropriateness of this deadline. Therefore, the EPA is soliciting comment on the proposed 14-day deadline for a follow-up OGI survey and information that would allow further evaluation of other potential deadlines to require.

Next, for sites with emissions identified during screening and subject to this follow-up OGI survey, the EPA proposes that any fugitive emissions identified must be repaired, including those emissions identified during the screening survey. For purposes of this proposal, the EPA is proposing the same repair deadlines as those for the ground based OGI requirements discussed in sections XI.A.2 and XI.A.3, which are a first attempt at repair within 30 days of the OGI survey and final repair completed within 30 days of the first attempt. As noted in section XI.A.1, some equipment types with large emissions warrant a requirement for root cause analysis rather than simply repairing the emission source. The EPA solicits comment on how that root cause analysis with corrective action approach could be applied in this proposed alternative screening approach. Further, because large emission events, especially those identified during the screening surveys, contribute disproportionately to emissions, the EPA is also soliciting comment on how to structure a requirement that would tier repair deadlines based on the severity of the fugitive emissions when using this proposed alternative standard. See section XI.A.2 for additional discussion of this solicitation on tiered repairs.

In addition to the bimonthly screening surveys proposed above, the EPA recognizes that component-level fugitive emissions may still be present at sites where the screening survey does not detect emissions. Therefore, in conjunction with these bimonthly screenings performed with the advanced measurement technology, the EPA is proposing to require a full OGI (or EPA Method 21) survey at least annually at each individual site utilizing the alternative screening standard. If the owner or operator performs an OGI survey in response to emissions found during the bimonthly screening survey, that OGI survey would count as the annual OGI survey; a second survey would not be required to comply with the annual OGI survey requirement and the clock would restart with the next annual survey due within 12 calendar months. The overall purpose of this annual OGI survey is to ensure that each individual site is surveyed with OGI at least annually, even where large emissions are not detected during the screening surveys using advanced measurement technology. The EPA is not allowing EPA Method 21 for use during the proposed follow-up OGI surveys when screening detects emissions because EPA Method 21 is not appropriate for detecting the sources of large emission events, such as malfunctioning control devices.

Finally, the EPA is proposing to require that owners and operators include information specific to the alternative standard within their fugitive emissions monitoring plan. Since the 2016 NSPS OOOOa, owners and operators have been required to develop and maintain a fugitive emissions monitoring plan for all sites subject to the fugitive emissions requirements. This monitoring plan includes information regarding which sites are covered under the plan, which technology is being used (*e.g.,* OGI or EPA Method 21), and site or company-

[199] ''Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging'' located at Docket ID No. EPA–HQ–OAR–2021–0317.

specific procedures that are employed to ensure compliant surveys. The EPA is proposing to add a requirement that the monitoring plan also address sites that are utilizing the proposed alternative standard. Specifically, the EPA is proposing a requirement to include the following information when the alternative standard is applied:

- Identification of the sites opting to comply with the alternative screening approach;
- General description of each site to be monitored, including latitude and longitude coordinates of the asset in decimal degrees to an accuracy and precision of five decimals of a degree using the North American Datum of 1983;
- Description of the measurement technology;
- Verification that the technology meets the 10 kg/hr methane detection threshold, including supporting data to demonstrate the sensitivity of the measurement technology as applied;
- Procedures for a daily verification check of the measurement sensitivity under field conditions (*e.g.,* controlled releases);
- Standard operating procedures consistent with EPA's guidance [200] and to include safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control (*i.e.,* initial and ongoing calibration procedures, data quality indicators, and data quality objectives); and
- Procedures for conducting the screening.

In the event that an owner or operator uses multiple technologies covered by one monitoring plan, the owner or operator would identify which technology is to be used on which site within the monitoring plan.

In addition to the proposed requirements within the monitoring plan, the EPA is also proposing specific recordkeeping and reporting requirements associated with the follow-up OGI surveys that are consistent with the recordkeeping and reporting required for OGI surveys in NSPS OOOOa as amended in the 2020 Technical Rule. See section X.B.1.h and X.B.1.i. The EPA is soliciting comment on when notifications would be required for sites where the alternative standard is applied. Further, the EPA is soliciting comment on whether submission of the monitoring plan, and/or Agency approval before utilizing the alternative standard is necessary to ensure consistency in screening survey procedures in the absence of finalized methods or procedures.

While the EPA is proposing the above alternative screening requirements, additional information is necessary to further refine the specific alternative work practice as it relates to the available technologies. Specific information is requested in the following paragraphs, and, if received, would allow the EPA to better analyze the BSER for fugitive emissions at well sites and compressor stations through a supplemental proposal.

First, the EPA solicits comment on the use of 10 kg/hr as the minimum detection threshold for the advanced measurement technologies used in the alternative screening approach, including data that would support consideration of another detection threshold. The EPA also solicits comment on whether a matrix approach should be developed, instead of prescribing one detection threshold and screening frequency, and what that matrix should look like. In the matrix approach, the frequency of the screening surveys and regular OGI (or EPA Method 21) surveys would be based on the sensitivity of the technology, with the most sensitive detection thresholds having the least frequent screening and survey requirements and the least sensitive detection thresholds having the most frequent screening and survey requirements. For example, sites that are screened using a technology with a detection threshold of 1 kg/hr may require less frequent screening and may require an OGI survey less frequently than sites screened using a technology with a detection threshold of 50 kg/hr. We are also soliciting comment on the detection sensitivity of commercially available methane detection technologies based on conditions expected in the field, as well as factors that affect the detection sensitivity and how the detection sensitivity would change with these factors.

Next, the EPA is soliciting comment on the standard operating procedures being used for commercially available technologies, including any manufacturer recommended data quality indicators and data quality objectives in use to validate these measurements. Additionally, for those commercially available technologies that quantify methane emissions rather than just detect methane, we are soliciting comment on the range of quantification based on conditions one would expect in the field.

The EPA is seeking information that would allow us to further evaluate the potential costs and assumed emission reductions achieved through an alternative screening program. Therefore, the EPA is seeking information on the cost of screening surveys using different types of advanced measurement technologies, singularly or in combination, and factors that affect that cost (*e.g.,* is it influenced by the number of sites and length of survey). Additionally, we are interested in understanding whether there would be opportunities for cost-sharing among operators and whether any aspect of regulation would be beneficial or required to facilitate such cost-sharing opportunities. We also solicit comment on whether these technologies and cost-sharing opportunities would allow for cost-effective monitoring at all sites owned or operated by the same company within a sub-basin or other discrete geographic area. Further, we seek comment on the current and expected availability of these advanced measurement technologies and the supporting personnel and infrastructure required to deploy them, how their cost and availability might be affected if demand for these technologies were to increase, and how quickly the use of these technologies could expand if they were integrated into this regulatory program either as a required element of fugitive monitoring or as this proposed alternative work practice.

The EPA recognizes that the approach outlined above may not be suited to continuous monitoring technologies, such as network sensors or open-path technology. While these systems typically have the ability to meet the 10 kg/hr methane threshold discussed above [201] the emissions from these well sites can be intermittent or tied to process events (*e.g.,* pigging operations). We are concerned that the proposed alternative screening approach would trigger an OGI survey for every emission event, regardless of type, duration, or size, if a continuous monitoring technology is installed. This would disincentivize the use of continuous monitoring systems, which could be valuable tools in finding large emission sources sooner. While we believe that a framework for advanced measurement technologies that monitor sites continuously should be developed, we do not currently have all of the information that is necessary to develop

[200] Guidance for Preparing Standard Operating Procedures (SOPs), EPA/600/B–07/001, April 2007, *https://www.epa.gov/sites/default/files/2015-06/documents/g6-final.pdf.*

[201] Alden et al., Single-Blind Quantification of Natural Gas Leaks from 1 km Distance Using Frequency Combs, *Environmental Science and Technology,* 2019, *53,* 2908–2917.

an equivalence demonstration for these monitors or to ensure the technology works appropriately over time. Therefore, we are soliciting comment on how an equivalence demonstration can be made for these continuous monitoring technologies.

The framework for a continuous monitoring technology would need to cover the following items at a minimum: The number of monitors needed and the placement of the monitors; minimum response factor to methane; minimum detection level; frequency of data readings; how to interpret the monitor data to determine what emissions are a detection versus baseline emissions; how to determine allowable emissions versus leaks; the meteorological data criteria; measurement systems data quality indicators; calibration requirements and frequency of calibration checks; how downtime should be handled; and how to handle situations where the source of emissions cannot be identified even when the monitor registers a leak. We are soliciting comment on how to develop a framework that is flexible for multiple technologies while still ensuring that emissions are adequately detected and the monitors respond appropriately over time. Additionally, we are soliciting comment on whether these continuous monitors need to respond to other compounds as well as methane; how close a meteorological station must be to the monitored site; and whether OGI or EPA Method 21 surveys should still be required, and if so, at what frequency.

At this time, the EPA does not have enough information to determine how this proposed alternative standard using advanced measurement technologies compares to the proposed BSER of OGI monitoring at well sites at a frequency that is based on the site baseline methane emissions as described in section XI.A.3.a, or to quarterly OGI monitoring at compressor stations. Information provided through this solicitation may be used to reevaluate BSER through a supplemental proposal.

6. Use of Information From Communities and Others

As the EPA learned during the Methane Detection Technology Workshop, industry, researchers, and NGOs have utilized advanced methane detection systems to quickly identify large emission sources and target ground based OGI surveys. State and local governments, industry, researchers, and NGOs have been utilizing advanced technologies to better understand the detection of, source of, and factors that lead to large emission events. The EPA anticipates that the use of these techniques by a variety of parties, including communities located near oil and gas facilities or affected by oil and gas pollution, will continue to grow as these technologies become more widely available and decline in cost.

The EPA is seeking comment on how to take advantage of the opportunities presented by the increasing use of these technologies to help identify and remediate large emission events (commonly known as ''super-emitters''). Specifically, the EPA seeks comment on how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event. The EPA understands that these large emission events are often attributable to malfunctions or abnormal process conditions that should not be occurring at a well-operating, well-maintained, and well-controlled facility that has implemented the various BSER measures identified in this proposal.

We generally envision a program for finding large emission events that consists of a requirement that, if emissions are detected above a defined threshold by a community, a Federal or State agency, or any other third party, the owner or operator would be required to investigate the event, do a root cause analysis, and take appropriate action to mitigate the emissions, and maintain records and report on such events.

We seek comment on all aspects of this concept, which would be developed further as part of a supplemental proposal. Among other things, the EPA is soliciting comment on an emissions threshold that could be used to define these large emission events, and which types of technologies would be suitable for identification of large emissions events. For example, there are some satellite systems capable of generally identifying emissions above 100 kg/hr with a spatial resolution which could allow identification of emission events from an individual site.[202] Additionally there are other satellites systems available which have wider spatial resolution that can identify large methane emission events, and when combined with finer resolution platforms, could allow identification of emission events from an individual site. The EPA believes that any emissions visible by satellites should qualify as large emission events. However, the EPA solicits comment on whether the threshold for a large emission should be lower than what is visible by satellite.

Second, in order to make this approach viable, the EPA would need to specify what actions an owner or operator must take when notified of a large emission event, including deadlines for taking such actions. These elements could include the specific steps the company would take to investigate the notification and mitigate the event, such as verifying the location of the emissions, conducting ground investigations to identify the specific emission source, conducting a root cause analysis, performing corrective action within a specific timeframe to mitigate the emissions, and preventing ongoing and future chronic or intermittent large emissions from that source. These steps could be incorporated into a fugitive emissions monitoring plan maintained by the owner or operator, and failure to take the actions specified by the owner or operator in the plan could be considered noncompliance. We seek comment on what specific follow-up actions or other procedures would be appropriate to require once a large emission event is identified, as well as appropriate deadlines for these actions.

Third, the EPA would need to define guidelines for credible and actionable data. The EPA is soliciting comment on what these guidelines should entail and whether specific protocols (*e.g.,* permissible detection technologies, data analytics, operator training, data reporting, public access, and data preservation) should govern the collection of such data and whether such data should conform to any type of certification. If specific certification or protocols are necessary, the EPA is soliciting comment on how that certification should be obtained.

Fourth, we are also soliciting comment on best practices for the identification of the correct owner or operator of a facility responsible for such large emissions, since such information is necessary to halt such large-volume emission events, and how the community or other third-party should notify the owner or operator, as well as how the delegated authority should be made aware of such notification.

Finally, we are soliciting comment on whether the EPA should develop a model plan for responding to notifications that companies could adopt instead of developing company- or site-specific plans, including what

[202] D.J. Varon, J. McKeever, D. Jervis, J.D. Maasakkers, S. Pandey, S. Houweling, I. Aben, T. Scarpelli, D.J. Jacob, *Satellite Discovery of anomalously Large Methane Point Sources from Oil/Gas Production,* available at *https://doi.org/10.1029/2019GL083798, October 25, 2019.*

elements should be included in that model plan.

B. Storage Vessels

1. NSPS OOOOb

The current NSPS in subpart OOOOa for storage vessels is to reduce VOC emissions by 95 percent, and the standard applies to a single storage vessel with a potential for 6 or more tpy of VOC emissions. Based on our analysis, which is summarized in section XII.B.1, the EPA is proposing to retain the 95 percent reduction standard as it continues to reflect the BSER for reducing VOC emissions from new storage vessels. The EPA is also proposing to set GHG standards (in the form of limitations on methane emissions) for storage vessels in this action. Because the BSER for reducing VOC and methane emissions are the same, the proposed GHG standard is to reduce methane emissions by 95 percent. The EPA continues to support the capture of gas vapors from storage vessels rather than the combustion of what can be an energy-rich saleable product. We incentivize this by recognizing the use of vapor recovery as a part of the process, therefore the storage vessel emissions would not contribute to the site's potential-to-emit.

Under the current NSPS for storage vessels, an affected facility is a single storage vessel with potential VOC emissions of 6 tpy or greater. The EPA is proposing to include a tank battery as a storage vessel affected facility. The EPA proposes to define a tank battery as a group of storage vessels that are physically adjacent and that receive fluids from the same source (*e.g.,* well, process unit, compressor station, or set of wells, process units, or compressor stations) or which are manifolded together for liquid or vapor transfer.

To determine whether a single storage vessel is an affected facility, the owner or operator would compare the 6 tpy VOC threshold to the potential emissions from that individual storage vessel; to determine whether a tank battery is an affected facility, the owner or operator would compare the 6 tpy VOC threshold to the aggregate potential emissions from the group of storage vessels. For new, modified, or reconstructed sources, if the potential VOC emissions from a storage vessel or tank battery exceeds the 6 tpy threshold, then it is a storage vessel affected facility and controls would be required. This is consistent with the EPA's initial determination in the 2012 NSPS OOOO that controlling VOC emissions as low as 6 tpy from storage vessels is cost-effective. The proposed standard of 95 percent reduction of methane and VOC emissions, which is the same as the current VOC standard in the 2012 NSPS OOOO and 2016 NSPS OOOOa, can be achieved by capturing and routing the emissions utilizing a cover and closed vent system that routes captured emissions to a control device that achieves an emission reduction of 95 percent, or that routes captured emissions to a process.

Finally, we are proposing specific provisions to clarify what circumstances constitute a modification of an existing storage vessel affected facility (single storage vessel or tank battery), and thus subject it to the proposed NSPS instead of the EG. The EPA is proposing that a single storage vessel or tank battery is modified when physical or operational changes are made to the single storage vessel or tank battery that result in an increase in the potential methane or VOC emissions. Physical or operational changes would be defined to include: (1) The addition of a storage vessel to an existing tank battery; (2) replacement of a storage vessel such that the cumulative storage capacity of the existing tank battery increases; and/or (3) an existing tank battery or single storage vessel that receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery). The EPA is proposing to require that the owner or operator recalculate the potential VOC emissions when any of these actions occur on an existing tank battery to determine if a modification has occurred. The existing tank battery will only become subject to the proposed NSPS if it is modified pursuant to this definition of modification and its potential VOC emissions exceed the proposed 6 tpy VOC emissions threshold.

2. EG OOOOc

Based on our analysis, which is summarized in section XII.B.2, the EPA is proposing EG for existing storage vessels which include a presumptive GHG standard (in the form of limitation on methane emissions). For existing sources under the EG, the EPA is proposing to define a designated facility as an existing tank battery with potential methane emissions of 20 tpy or greater. The proposed definition of a tank battery in the EG is the same as the definition proposed for new sources; however, since the designated pollutant in the context of the EG is methane, determination of whether a tank battery is a designated facility would be based on its potential methane emissions only. Our analysis shows that it is cost effective to control an existing tank battery with potential methane emissions 20 tpy or higher. Similar to the proposed NSPS, we are proposing a presumptive standard that includes a 95 percent reduction of the methane emissions from each existing tank battery that qualifies as a designated facility. Such a standard could be achieved by capturing and routing the emissions by utilizing a cover and closed vent system that routes captured emissions to a control device that achieves an emission reduction of 95 percent, or routes emission back to a process.

C. Pneumatic Controllers

1. NSPS OOOOb

The current NSPS OOOOa regulates certain continuous bleed natural gas driven pneumatic controllers, but includes different standards based on whether the pneumatic controller is located at an onshore natural gas processing plant. If the pneumatic controller is located at an onshore natural gas processing plant, then the current NSPS requires a zero bleed rate. If the pneumatic controller is located elsewhere, then the current NSPS requires the pneumatic controller to operate at a natural gas bleed rate no greater than 6 scfh. The current NSPS does not regulate intermittent vent natural gas driven pneumatic controllers at any location.

Based on our analysis, which is summarized in section XII.C.1, the EPA is proposing pneumatic controller standards for NSPS OOOOb as follows. First, in addition to each single natural gas-driven continuous bleed pneumatic controller being an affected facility, the EPA proposes to define each natural gas-driven intermittent vent pneumatic controller as an affected facility. The EPA believes these pneumatic controllers should be covered by NSPS OOOOb because natural gas-driven intermittent devices represent a large majority of the overall population of pneumatic controllers and are responsible for the majority of emissions from these sources. We are proposing to define an intermittent vent natural gas-driven pneumatic controller as a pneumatic controller that is not designed to have a continuous bleed rate but is instead designed to only release natural gas to the atmosphere as part of the actuation cycle. This affected facility definition would apply at all sites, including natural gas processing plants.

Second, we are proposing a requirement that all controllers

(continuous bleed and intermittent vent) must have a VOC and methane emission rate of zero. The proposed rule does not specify how this emission rate of zero must be achieved, but a variety of viable options are discussed in Section XII.C. including the use of pneumatic controllers that are not driven by natural gas such as air-driven pneumatic controllers and electric controllers, as well as natural gas driven controllers that are designed so that there are no emissions, such as self-contained pneumatic controllers. As noted above, the EPA is proposing that the definition of an affected facility would be each pneumatic controller that is driven by natural gas and that emits to the atmosphere. As such, pneumatic controllers that are not driven by natural gas would not be affected facilities, and thus would not be subject to the pneumatic controller requirements of NSPS OOOOb. Similarly, controllers that are driven by natural gas but that do not emit to the atmosphere would also not be affected facilities. In order to demonstrate that a particular pneumatic controller is not an affected facility, owners and operators should maintain documentation to show that such controllers are not natural gas driven such as documentation of the design of the system, and to ensure that they are operated in accordance with the design so that there are no emissions.

In both NSPS OOOO and OOOOa, there is an exemption from the standards in cases where 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. The EPA is not maintaining this exemption in the proposed NSPS OOOOb, except for in very limited circumstances explained in section XII.C. As discussed in section XII.C., the reasons to allow for an exemption based on functional need in NSPS OOOO and OOOOa were based on the inability of a low-bleed controller to meet the functional requirements of an owner/operator such that a high-bleed controller would be required in certain instances. Since we are now proposing that pneumatic controllers have a methane and VOC emission rate of zero, we do not believe that the reasons related to the use of low bleed controllers are still applicable. However, EPA is soliciting comment on whether owners/operators believe that maintaining such an exemption based on functional need is appropriate, and if so why.

The proposed rule includes an exemption from the zero-emission requirement for pneumatic controllers in Alaska at locations where power is not available. In these situations, the proposed standards require the use of a low-bleed controller instead of high-bleed controller. Further, in these situations (controllers in Alaska at location without power) the proposed rule includes the exemption that would allow the use of high-bleed controllers instead of low-bleed based on functional needs. Lastly, in these situations owners/operators must inspect intermittent vent controllers to ensure they are not venting during idle periods.

2. EG OOOOc

In this action, the EPA is proposing to define designated facilities (existing sources) analogous to the affected facility definitions described above for pneumatic controllers under the NSPS. For the reasons discussed in section XII.C.2, the BSER analysis for existing sources supports proposing presumptive standards for reducing methane emissions from existing pneumatic controllers that are the same as those the EPA is proposing for new, modified, or reconstructed sources (for NSPS OOOOb).

D. Well Liquids Unloading Operations

Well liquids unloading operations, which are currently unregulated under the NSPS OOOOa, refer to unloading of liquids that have accumulated over time in gas wells and are impeding or halting production. The EPA is proposing standards in the NSPS OOOOb to reduce methane and VOC emissions during liquids unloading operations.

1. NSPS OOOOb

We are proposing standards to reduce VOC and methane emissions from each well that conducts a liquids unloading operation. Based on our analysis, which is summarized in section XII.D.1, we are proposing a standard under NSPS OOOOb that requires owners or operators to perform liquids unloading with zero methane or VOC emissions. In the event that it is technically infeasible or not safe to perform liquids unloading with zero emissions, the EPA is proposing to require that an owner or operator establish and follow BMPs to minimize methane and VOC emissions during liquids unloading events to the extent possible.

The EPA is co-proposing two regulatory approach options to implement the rule requirements.

For Option 1, the affected facility would be defined as every well that undergoes liquids unloading. This would mean that wells that utilize a non-emitting method for liquids unloading would be affected facilities and subject to certain reporting and recordkeeping requirements. These requirements would include records of the number of unloadings that occur and the method used. A summary of this information would also be required to be reported in the annual report. The EPA also recognizes that under some circumstances venting could occur when a selected liquids unloading method that is designed to not vent to the atmosphere is not properly applied (*e.g.,* a technology malfunction or operator error). Under the proposed rule Option 1 owners and operators in this situation would be required to record and report these instances, as well as document and report the length of venting, and what actions were taken to minimize venting to the maximum extent possible.

For wells that utilize methods that vent to the atmosphere, the proposed rule would require that owners or operators (1) Document why it is infeasible to utilize a non-emitting method due to technical, safety, or economic reasons; (2) develop BMPs that ensure that emissions during liquids unloading are minimized including, at a minimum, having a person on-site during the liquids unloading event to expeditiously end the venting when the liquids have been removed; (3) follow the BMPs during each liquids unloading event and maintain records demonstrating they were followed; and (4) report the number of liquids unloading events in an annual report, as well as the unloading events when the BMP was not followed. While the proposed rule would not dictate all of the specific practices that must be included, it would specify minimum acceptance criteria required for the types and nature of the practices. Examples of the types and nature of the required practice elements are provided in XII.D.1.e.

For Option 2, the affected facility would be defined as every well that undergoes liquids unloading using a method that is not designed to totally eliminate venting. The significant difference in this option is that wells that utilize non-venting methods would not be affected facilities that are subject to the NSPS OOOOb. Therefore, they would not have requirements other than to maintain records to document that they used non-venting liquids unloading methods. The requirements for wells that use methods that vent would be the same as described above under Option 1. The EPA solicits comment on including information such as where the well stream was directed during unloading and emissions

manifested and whether an estimate of the VOC and methane emissions generated should be included in the annual report.

There are several techniques owners and operators can choose from to unload liquids, including manual unloading, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps, intermittent unloading, gas lift (*e.g.,* use of a plunger lift), foam agents, wellhead compression, and routing the gas to a sales line or back to a process. Although the unloading method employed by an owner or operator can itself be a method that can be employed in such a way that mitigates/eliminates venting of emissions from a liquids unloading event, indicating a particular method to meet a particular well's unloading needs is a production engineering decision. Based on available information, liquids unloading operations are often conducted in such a way that eliminates venting to the atmosphere and there are many options that include techniques and procedures that an owner or operator can choose from to achieve this standard (discussed in section XII.D.e of this preamble).

However, the EPA recognizes that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible for such cases (discussed in section XII.D of this preamble). BMPs include, but are not limited to, following specific steps that create a differential pressure to minimize the need to vent a well to unload liquids and reducing wellbore pressure as much as possible prior to opening to atmosphere via storage tank, unloading through the separator where feasible, and requiring an operator to remain on-site throughout the unloading, and closure of all well head vents to the atmosphere and return of the well to production as soon as practicable. For example, where a plunger lift is used, the plunger lift can be operated so that the plunger returns to the top and the liquids and gas flow to the separator. Under this scenario, venting of the gas can be minimized and the gas that flows through the separator can be routed to sales. In situations where production engineers select an unloading technique that vents emissions or has the potential to vent emissions to the atmosphere, owners and operators already often implement BMPs in order to increase gas sales and reduce emissions and waste during these (often manual) liquids unloading activities.

2. EG OOOOc

The EPA has determined that each well liquids unloading event represents a modification, which will make the well subject to new source standards under the NSPS for purposes of the liquids unloading standards.[203] Therefore, after the effective date of NSPS OOOOb, the first time a well undergoes liquids unloading it will become subject to NSPS OOOOb. This will mean that there will never be a well that undergoes liquids unloading that will be existing. Therefore, we are not proposing presumptive standards under the subpart OOOOc EG.

E. Reciprocating Compressors

1. NSPS OOOOb

The current NSPS in subpart OOOOa for reducing VOC and methane emissions from reciprocating compressors is to replace the rod packing on or before 26,000 hours of operation or 36 calendar months, or to route emissions from the rod packing to a process through a closed vent system under negative pressure. The affected facility is each reciprocating compressor, with the exception of reciprocating compressors located at well sites. Based on the analysis in section XII.E.1, the proposed BSER for reducing GHGs and VOC from new reciprocating compressors is replacement of the rod packing based on an annual monitoring threshold. Under this proposal for the NSPS, we would continue to retain, as an alternative, the option of routing rod packing emissions to a process via a closed vent system under negative pressure. In this proposed updated standard, the owner or operator of a reciprocating compressor affected facility would be required to monitor the rod packing emissions annually using a flow measurement. When the measured leak rate exceeds 2 scfm (in pressurized mode), replacement of the rod packing would be required.

As mentioned above, reciprocating compressors that are located at well sites are not affected facilities under the 2016 NSPS OOOOa. The EPA previously excluded them because we found the cost of control to be unreasonable. 81 FR 35878 (June 3, 2016). Our current analysis, as summarized in section XII.E.1, continues to support this exclusion for a subset of well sites so this proposal for NSPS OOOOb includes that same exclusion for well sites that are not centralized production facilities. See section XI.L for additional details on centralized production facilities. As described in that section, the EPA is proposing to apply the proposed standards to reciprocating compressors located at centralized production facilities.

2. EG OOOOc

Based on the analysis in section XII.E.2, the EPA is proposing EG that include a presumptive GHG standard (in the form of limitation on methane emissions) for existing reciprocating compressors that is the same as the proposed NSPS, including applying these presumptive standards to reciprocating compressors located at existing centralized tank batteries.

F. Centrifugal Compressors

1. NSPS OOOOb

The current NSPS in subpart OOOOa for wet seal centrifugal compressors is 95 percent reduction of GHGs and VOC emissions. The affected facility is each wet seal centrifugal compressor, with the exception of wet seal centrifugal compressors located at well sites. Based on the analysis in section XII.F.1, the BSER for reducing GHGs and VOC from new, reconstructed, or modified wet seal centrifugal compressors is the same as the current standard, which is 95 percent reduction of GHG and VOC emissions. The standard can be achieved by capturing and routing the emissions, using a cover and closed vent system, to a control device that achieves an emission reduction of 95 percent, or by routing captured emissions to a process.

As discussed above, wet seal centrifugal compressors that are located at well sites are not affected facilities under the 2016 NSPS OOOOa. The EPA previously excluded them because data available at the time did not suggest there were a large number of wet seal centrifugal compressors located at well sites. 81 FR 35878 (June 3, 2016). Our analysis continues to support this exemption for wet seal centrifugal compressors located at well sites that are not centralized production facilities. See section XI.L for additional details on centralized production facilities. As described in that section, the EPA is proposing to apply the proposed standards to centrifugal compressors located at centralized production facilities.

2. EG OOOOc

Based on the analysis in section XII.F.2, the EPA is proposing EG that

[203] To clarify further, when a well liquids unloading event represents a modification, this does not make the whole well site a new source. Rather, the modification will make the well subject to NSPS for only the liquids unloading standards.

include a presumptive GHG standard (in the form of limitation on methane emissions) for existing wet seal centrifugal compressors that is the same as the NSPS, including applying these presumptive standards to wet seal centrifugal compressors at existing centralized tank batteries.

G. Pneumatic Pumps

1. NSPS OOOOb

The current NSPS in subpart OOOOa regulates individual natural gas driven diaphragm pneumatic pumps at well sites and at onshore natural gas processing plants. The current NSPS for a natural gas driven diaphragm pneumatic pump at well sites requires 95 percent control of GHGs and VOCs if there is an existing control device or process on site where emissions can be routed. There are two exceptions to the 95 percent control requirement: (1) The existing control or process achieves less than 95 percent reduction; or (2) it is technically infeasible to route to the existing control device or process. In addition, the current NSPS in OOOOa specifies that boilers and process heaters are not considered control devices and that routing emissions from pneumatic pump discharges to boilers and process heaters is not considered routing to a process. For more discussion on the use of boilers and process heaters as control devices for pneumatic pump emissions, see section X.B.2 of this preamble. The current NSPS for a natural gas driven diaphragm pneumatic pump at an onshore natural gas processing plant is a natural gas emission rate of zero, based on natural gas as a surrogate for VOC and GHG, the two regulated pollutants.

For NSPS OOOOb, we are proposing to expand the applicability of the standard currently in NSPS OOOOa in two ways. The first is by including all natural gas driven diaphragm pumps as affected facilities in the transmission and storage segment in addition to the production and natural gas processing segments. The second is that we are expanding the affected facility definition to include natural gas driven piston pumps in addition to diaphragm pumps. The proposed definition of an affected facility would continue to exclude lean glycol circulation pumps that rely on energy exchange with the rich glycol from the contractor.

Based on our analysis, which is summarized in section XII.G.1, we are proposing to retain the current standard for a natural gas driven diaphragm pneumatic pump at well sites because the BSER for reducing VOC and methane emissions from such pumps at a well site continues to be routing to a combustion device or process, but only if the control device or process is already available on site. As before, the current analysis continues to show that it is not cost-effective to require the owner or operator of a pneumatic pump to install a new control device or process onsite to capture emissions solely for this purpose. Moreover, even where a control device or process is available onsite that would achieve at least 95 percent control, the EPA is aware that it may not be technically feasible in some instances to route the pneumatic pump to the control device or process. In this situation, the proposed rule would exempt the owner and operator from this requirement provided that they document the technical infeasibility and submit it in an annual report. Another circumstance is that it may be feasible to route the emissions to a control device, but the control cannot achieve 95 percent control. In this instance, the proposed rule would exempt the owner or operator from the 95 percent requirement, provided that the owner or operator maintain records demonstrating the percentage reduction that the control device is designed to achieve. In this way, the standard would achieve emission reductions with regard to pneumatic pump affected facilities even if the only available control device cannot achieve a 95 percent reduction. For more discussion of the technical infeasibility aspects of the pneumatic pump requirements, see section X.B.2 of this preamble. We are proposing to expand these requirements to all diaphragm pumps at all sites in the production segment, as well as at all transmission and storage sites. In addition, we are proposing that these requirements would also include emissions from piston pneumatic pumps at all sites in the production segment.

We are not proposing any change to the current standard of zero natural gas emission for natural gas driven diaphragm pneumatic pumps located at onshore natural gas processing plants, other than the expansion of the affected facility definition to include piston pumps. Our analysis discussed in section XII.G.1 demonstrates this standard is the BSER.

2. EG OOOOc

The EPA is proposing EG that include presumptive methane standards that are the same as described above for the NSPS OOOOb for existing natural gas driven diaphragm pneumatic pumps located at well sites and all other sites in the production segment (except processing plants) and transmission and storage segment where an existing control device exists. However, unlike the proposed methane standards in NSPS OOOOb for natural gas driven piston pneumatic pumps at sites in the production segment, the proposed presumptive standards under EG OOOOc exclude piston pumps from the 95 percent control requirements. The EPA's proposed emissions guidelines also include a presumptive methane standard for pneumatic pumps located at onshore natural gas processing plants that is the same as the proposed NSPS described above.

H. Equipment Leaks at Natural Gas Processing Plants

Based on our analysis, which is summarized in section XII.H.1, the EPA is proposing to update the NSPS for reducing VOC and methane emissions from equipment leaks at onshore natural gas processing plants. Further, based on the same analysis in section XII.H.1 and the EPA's understanding that it is appropriate to apply that same analysis to existing sources, the EPA is also proposing EG that include these same LDAR requirements as presumptive standards for reducing methane leaks from existing equipment at onshore natural gas processing plants.

The EPA is proposing to expand the definition of an affected facility (referred to as a ''equipment within a process unit'') and establish a new standard for reducing equipment leaks of VOC and methane emissions from new, modified, and reconstructed process units at onshore natural gas processing plants. This proposed standard would require (1) the use of OGI monitoring to detect equipment leaks from pumps, valves, and connectors, and (2) retain the current requirements in the 2016 NSPS OOOOa (which adopts by reference specific provisions of 40 CFR part 60, subpart VVa (''NSPS VVa'')) for PRDs, open-ended valves or lines, and closed vent systems and equipment designated with no detectable emissions.

First, we are proposing to remove a threshold that excludes certain equipment within a process unit from being subject to the equipment leaks standards for onshore natural gas processing plants. While the current definition of an affected facility includes all equipment, except compressors, that is in contact with a process fluid containing methane or VOCs (*i.e.,* each pump, PRD, open-ended valve or line, valve, and flange or other connector), the standards apply only to equipment ''in VOC service,''

which ''means the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight.'' We are proposing to remove this VOC concentration threshold from the LDAR requirements for the following reasons. First, a VOC concentration threshold bears no relationship to the LDAR for methane and is therefore not an appropriate threshold for determining whether LDAR for methane applies. Second, since there would be no threshold for requiring LDAR for methane, any equipment not in VOC service would still be required to conduct LDAR for methane even if not for VOC, thus rendering this VOC concentration threshold irrelevant.

Second, for all pumps, valves, and connectors located within an affected process unit at an onshore natural gas processing plant, we are proposing to require the use of OGI to identify leaks from this equipment on a bimonthly frequency (*i.e.,* once every other month), which according to our analysis is the BSER for identifying and reducing leaks from this equipment. OGI monitoring would be conducted in accordance with the proposed appendix K,[204] which is included in this action and outlines the proposed procedures that must be followed to identify leaks using OGI. As an alternative to bimonthly monitoring using OGI, we are proposing to allow affected facilities the option to comply with the requirements of NSPS VVa, which are the current requirements in the 2016 NSPS OOOOa.[205] As explained in XII.A, our analysis shows that the proposed standards, which use OGI, achieve equivalent reduction of VOC and methane emissions as the current standards, which are based on EPA Method 21, but at a lower cost. While we no longer consider EPA Method 21 to be the BSER for reducing methane and VOC emissions from equipment leaks at onshore natural gas processing plants, we are retaining NSPS VVa as an alternative for owners and operators who prefer using EPA Method 21.

Third, we are proposing to require a first attempt at repair for all leaks identified with OGI within 5 days of detection, and final repair completed within 15 days of detection. We are also proposing definitions for ''first attempt at repair'' and ''repaired.'' The proposed definitions would apply to the equipment leaks standards at natural gas processing plants as well as to fugitive emissions requirements at well sites and compressor stations. The proposed definition of ''first attempt at repair'' is an action taken for the purpose of stopping or reducing fugitive emissions or equipment leaks to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing. The proposed definition for ''repaired'' is fugitive emissions components or equipment are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions or equipment leaks as defined in the subpart and resurveyed to verify that emissions from the fugitive emissions components or equipment are below the applicable leak definition. Repairs can include replacement with low-emissions (''low-e'') valves or valve packing, where commercially available, as well as drill-and-tap with a low-e injectable. These low-e equipment meet the specifications of API 622 or 624. Generally, a low-e valve or valve packing product will include a manufacturer written warranty that it will not emit fugitive emissions at a concentration greater than 100 ppm within the first five years. Further, we are proposing to incorporate the delay of repair provisions that are in 40 CFR 60.482–9a of NSPS VVa (and incorporated into NSPS OOOOa). These provisions would allow the delay of repairs where it is technically infeasible to complete repairs within 15 days without a process unit shutdown and require repair completion before the end of the next process unit shutdown.

Fourth, we are proposing to retain the current requirements in NSPS OOOOa for open-ended valves or lines, closed vent systems and equipment designated with no detectable emissions, and PRDs. For open-ended valves or lines, we propose to retain the requirements in 40 CFR 60.482–6a of NSPS VVa. Specifically, we are proposing that each open-ended valve or line in a new or existing process unit must be equipped with a closure device (*i.e.,* cap, blind flange, plug, or a second valve) that seals the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. The EPA is soliciting comment on requiring OGI monitoring (or EPA Method 21 monitoring for those opting for that alternative) on these open-ended valves or lines equipped with closure devices to ensure no emissions are going to the atmosphere. Specifically, the EPA is soliciting information that would aid in determining what additional costs would be incurred from either OGI or EPA Method 21 monitoring and repair of leaking open-ended valves or lines, and information on leak rates and concentrations of emissions, where monitoring has been performed.

While the EPA is proposing to retain the no detectable emission requirement in NSPS OOOOa for closed vent systems and equipment designated as having no detectable emissions (*e.g.,* valves or PRDs), the EPA is also soliciting comment on whether bimonthly OGI monitoring according to the proposed appendix K is appropriate to demonstrate compliance with this requirement. The current NSPS requires the closed vent systems[206] and the other equipment described above to operate with no detectable emissions, as demonstrated by an instrument reading of less than 500 ppm above background with EPA Method 21. On December 22, 2008, the EPA issued a final rule titled, ''Alternative Work Practice to Detect Leaks from Equipment'' (*AWP*).[207] In that final rule, the EPA did not permit the use of OGI for this equipment, stating, ''the AWP is not appropriate for monitoring closed vent system, leakless equipment, or equipment designated as non-leaking. While the AWP will identify leaks with larger mass emission rates, tests conducted with both the AWP and the current work practice indicate the AWP, at this time, does not identify very small leaks and may not be able to identify if non-leaking/leakless equipment are truly nonleaking because the detection sensitivity of the optical gas imaging instrument is not sufficient.'' 73 FR 78204 (December 22, 2008). The EPA is soliciting information that would support the use of OGI for closed vent systems and equipment designated with no detectable emissions at new and existing process units, including comment on applying the proposed bimonthly OGI monitoring requirement on this equipment in place

[204] ''Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging'' located at Docket ID No. EPA–HQ–OAR–2021–0317.

[205] It is important to note that the stay of the connector monitoring requirements in 40 CFR 60.482–11a does not apply to connectors located at onshore natural gas processing plants. Therefore, where sources choose to comply with the requirements of NSPS VVa in place of the proposed OGI requirements, the standards in 40 CFR 60.482–11a are applicable to all connectors in the process unit.

[206] For purposes of this standard, the EPA is referring to closed vent systems used equipment within process units at onshore natural gas processing plants. Closed vent systems associated with controlled storage vessels, wet seal centrifugal compressors, reciprocating compressors and pneumatic pumps are not included in this discussion and would demonstrate compliance with the no detectable emissions standard by EPA Method 21 (except for storage vessels), monthly AVO, or OGI monitoring during the fugitive emissions survey.

[207] See 73 FR 78199 (December 22, 2008).

of the NSPS VVa annual EPA Method 21 monitoring.

Finally, the EPA is proposing to retain the emission standards for PRDs found in 40 CFR 60.482–4a of NSPS VVa. This provision requires that PRDs be operated with no detectable emissions, except during pressure releases at new and existing process units. As stated above, the EPA is soliciting comment on the use of OGI to demonstrate that PRDs are meeting this operational emission standard.

2. EG OOOOc

The EPA is proposing EG that include a presumptive methane standard that is the same as described above for the NSPS OOOOb for equipment leaks at existing onshore natural gas processing plants. Based on the analysis in section XII.H.2, the BSER for reducing GHGs from equipment leaks at new and existing onshore natural gas processing plants are the same.

I. Well Completions

Based on our understanding that there are no advances in technologies or practices, which is summarized in section XII.I, the EPA is proposing to retain the REC and completion combustion requirements for reducing methane and VOC emissions from well completions of hydraulically fractured or refractured oil and natural gas wells, as they continue to reflect the BSER. These proposed standards are the same as those for natural gas and oil wells regulated in the 2012 NSPS OOOO and 2016 NSPS OOOOa, as amended in the 2020 Technical Rule for VOC and proposed in section X.B.1 for methane.[208] Because of the nature of well completions, any completion (or recompletion) is considered a new or modified well affected facility, therefore, the EPA does not believe there are existing well affected facilities to which a EG OOOOc presumptive standard for well completions would apply.

J. Oil Wells With Associated Gas

Associated gas originates at wellheads that also produce hydrocarbon liquids and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation. There are no current NSPS requirements for this emission source. The EPA is proposing standards in the NSPS OOOOb to reduce methane and VOC emissions resulting from the venting of associated gas from oil wells.

1. NSPS OOOOb

We are proposing standards to reduce methane and VOC emissions from each oil well that produces associated gas. Based on our analysis, which is summarized in section XII.J, we are proposing a standard under NSPS OOOOb that requires owners or operators of oil wells to route associated gas to a sales line. In the event that access to a sales line is not available, we are proposing that the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions. As discussed in section XII.J, the EPA is soliciting comment on how ''access to a sales line'' should be defined. An affected facility would be defined as any oil well that produces associated gas. The proposed rule would require that when using a flare, the flare must meet the requirements in 40 CFR 60.18 and that monitoring, recordkeeping, and reporting be conducted to ensure that the flare is constantly achieving the required 95 percent reduction. As discussed in section XII.J, the EPA is soliciting comment on an alternative affected facility definition that would exclude oil wells that route all associated gas to a sales line. The EPA is also soliciting comment and information that would support requirements using other strategies to reduce venting and flaring of associated gas from oil wells. The EPA is specifically requesting comment on whether the proposed requirements will incentivize the sale or productive use of captured gas, and if not, other methods that the EPA could use to incentivize or require the sale or productive use instead of flaring.

2. EG OOOOc

The EPA is proposing presumptive standards for existing oil wells in this action that are the same as discussed above for new sources.

K. Sweetening Units

Based on our understanding that no advances in technologies or practices are available to reduce SO_2 emissions from sweetening units, as described in section XII.K, the EPA is proposing to retain the standards as it continues to reflect the BSER. These proposed standards are the same as those for sweetening units regulated in the 2016 NSPS OOOOa, and as amended in the 2020 Technical Rule.[209]

L. Centralized Production Facilities

The EPA is also proposing a new definition for ''centralized production facility,'' which is one or more permanent storage tanks and all equipment at a single stationary source used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations. The EPA is proposing this definition to (1) specify how the fugitive emissions requirement apply to centralized production facilities, (2) specify how exemptions related to 40 CFR part 60, subpart K, Ka, or Kb (''NSPS Kb) may apply, and (3) specify what standards would apply to reciprocating and centrifugal compressors located at these facilities.

First, the EPA is proposing to specify how the fugitive emission requirements apply to centralized production facilities. The 2016 NSPS OOOOa, as originally promulgated, provided that ''[f]or purposes of the fugitive emissions standards at 40 CFR 60.5397a, [a] 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).'' 40 CFR 60.5430a. The inclusion of centralized tank batteries in the definition of well site was used to clarify the boundary of a well site for purposes of the fugitive emissions requirements. Further, in the RTC[210] for the 2016 NSPS OOOOa we stated, ''[o]ur intent is to limit the oil and gas production segment up to the point of custody transfer to an oil and natural gas mainline pipeline (including transmission pipelines) or a natural gas processing plant. Therefore, the collection of fugitive emissions components within this boundary are a part of the well site.'' The EPA continues to define these facilities as a type of well site but is proposing a separate definition to provide further

[208] See Docket ID No. EPA–HQ–OAR–2021–0317 for proposed redline regulatory text for 40 CFR 60.5375a as a reference for the specific well completion standards proposed for NSPS OOOOb.

[209] See Docket ID No. EPA–HQ–OAR–2021–0317 for proposed redline regulatory text for 40 CFR 60.5375a as a reference for the specific well completion standards proposed for NSPS OOOOb.

[210] See Document ID No. EPA–HQ–OAR–2010–0505–7632 at page 4–194.

clarity, especially as it relates to when these facilities are modified, and thus become subject to the fugitive emissions requirements in NSPS OOOOb. The EPA has determined it is appropriate to rename this site as a centralized production facility and to provide the specific definition above to avoid confusion with the storage vessel affected facility, of which applicability is determined for a tank battery, and to better specify the facility name based on the basic function the site performs (*i.e.,* production operations).

Second, the EPA has received questions related to whether NSPS Kb would apply to the storage vessels at centralized production facilities. There is an exemption in NSPS Kb for storage vessels in the producing operations that are below a specific size. Specifically, 40 CFR 60.110(b)(4) exempts ''vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.'' This exemption is a revision of an exemption originally promulgated in 40 CFR part 60, subpart K (''NSPS K''). NSPS K ''does not apply to storage vessels for the crude petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.'' 40 CFR 60.110(b). In that final rule the EPA explained that, ''[t]he storage of crude oil and condensate at producing fields is specifically exempted from the standard.'' 39 FR 9312 (March 8, 1974). While ''producing fields'' were not explicitly defined, NSPS K defined the terms ''custody transfer'' and ''drilling and production facility''. For purposes of NSPS K, custody transfer means ''the transfer of produced crude petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.'' 40 CFR 60.111(g). Drilling and production facility means ''all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of crude petroleum but does not include natural gasoline plants.'' 40 CFR 60.111(h). The definition of ''custody transfer'' was later also incorporated into 40 CFR part 60, subpart Ka (''NSPS Ka''), NSPS Kb, and 40 CFR part 63, subpart HH (National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities).

Instead of a categorical exemption for storage vessels located at drilling and production facilities, NSPS Ka, and subsequently NSPS Kb, adopted threshold-based exemptions that are based on the capacity of an individual storage vessel used to store petroleum (crude oil) or condensate prior to custody transfer. In NSPS Ka, the EPA stated ''[t]his exemption applies to storage between the time that the petroleum liquid is removed from the ground and the time that custody of the petroleum liquid is transferred from the well or producing operations to the transportation operations'' 45 FR 23377 (April 4, 1980). In NSPS Kb, the EPA further stated that ''[t]he promulgated standards for petroleum liquid storage vessels specifically exempted vessels with a capacity less than 420,000 gallons and storing petroleum (crude oil) and condensate prior to custody transfer (production vessels). The emission controls that are applicable to the storage vessels included in the standards being proposed are not applicable to production vessels.'' 49 FR 29701.

The EPA finds it inappropriate to use the controls required by NSPS K, Ka, and Kb on storage vessels located in the production segment, especially where flash emissions are prevalent. Specifically, the NSPS K, Ka, and Kb control requirements include provisions allowing the use of floating roofs to reduce emissions from storage tanks. Floating roofs are not designed to store liquid (or gases) under pressure. Pressurized liquid sent to a storage vessel from a well or separator or other process that operates above atmospheric pressure may contain dissolved gases. These gases will be released or ''flash'' from the liquid as the fluid comes to equilibrium with atmospheric pressure within the storage vessel. The flash gas will either be released from gaps in the seal system or from ''rim vents'' on the floating roof. The rim vent may be an open tube or may be fitted with a low-pressure relief valve, but it is specifically designed to allow any gas entrained or dissolved in the storage liquid to be released above the floating roof. That is, floating roofs are not designed to prevent the release of flash gas, they are only designed to limit the volatilization of a liquid that occurs when the storage liquid is directly exposed with unsaturated air. Since a significant portion of emissions from storage vessels at well sites or centralized production facilities are from flash gas, floating roofs are much less effective at reducing storage vessel emissions than venting these emissions through a CVS to a control or recovery device.

Further, it is the EPA's understanding that these centralized production facilities carry out the same operations that would be conducted at the individual well sites. Therefore, the EPA is proposing a definition of ''centralized production facility'' that clearly specifies these facilities are located within the producing operations. Therefore, if all other conditions are met (*i.e.,* vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer), storage vessels at these centralized facilities would meet the exemption criteria for NSPS Kb.

Alternatively, the EPA is soliciting comment on whether it would be more appropriate to specify within the proposed NSPS OOOOb and EG OOOOc that storage vessels at well sites and centralized production facilities are subject to the requirements in NSPS OOOOb and EG OOOOc instead of NSPS K, Ka, or Kb. This alternative approach would eliminate the need for sources to determine if the storage vessel meets the exemption criteria specified in those subparts and instead focus on appropriate controls for the storage vessels based on the location and type of emissions likely present (*e.g.,* flash emissions).

Finally, the EPA is now proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities'' above. In the 2016 NSPS OOOOa, the EPA exempted reciprocating and centrifugal compressors located at well sites from the applicable compressor standards.

Reciprocating compressors that are located at well sites are not affected facilities under the 2016 NSPS OOOOa. The EPA previously excluded them because we found the cost of control to be unreasonable. 81 FR 35878. However, as mentioned above, the EPA believes the definition of ''well site'' in NSPS OOOOa may cause confusion regarding whether reciprocating compressors located at centralized production facilities are also exempt from the standards. In our current analysis, described in section XII.E, we find it is appropriate to apply the same emission factors to reciprocating compressors located at centralized production facilities as those used for reciprocating compressors at gathering and boosting compressor stations. Given the results of that analysis, the EPA is proposing to apply the proposed NSPS OOOOb and presumptive standards in EG OOOOc to

reciprocating compressors located at centralized production facilities. The new definition above is intended to apply the results of the EPA's analysis. We believe that this new definition is necessary in the context of reciprocating compressors to distinguish between these compressors at centralized production facilities where the EPA has determined that the standard should apply, and these compressors at standalone well sites where the EPA has determined that the standard should not apply. See section XII.E for more details of those proposed standards.

Similarly, wet seal centrifugal compressors that are located at well sites are not affected facilities under the 2016 NSPS OOOOa. The EPA previously excluded them because data available at the time did not suggest there were a large number of wet seal centrifugal compressors located at well sites. 81 FR 35878. In our current analysis, described in section XII.F, we find it is appropriate to apply the same emission factors to wet seal centrifugal compressors located at centralized production facilities as those used for these same compressors at gathering and boosting compressor stations. Given the results of that analysis, the EPA is proposing to apply the proposed NSPS OOOOb and presumptive standards in EG OOOOc to wet seal centrifugal compressors located at centralized production facilities. See section XII.F for more details of those proposed standards.

M. Recordkeeping and Reporting

The EPA is proposing to require electronic reporting of performance test reports, annual reports, and semiannual reports through the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) at *https://cdx.epa.gov/*.) A description of the electronic data submission process is provided in the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* available in the docket for this action. Performance test results collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [211] at the time of the test would be required to be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and other performance test results would be submitted in portable document format (PDF) using the attachment module of the ERT. For semiannual and annual reports, the owner or operator would be required to use the appropriate spreadsheet template to submit information to CEDRI.

The EPA is also proposing to allow owners and operators the ability to seek extensions for submitting electronic reports for circumstances beyond the control of the facility, *i.e.,* for a possible outage in CDX or CEDRI or for a *force majeure* event, in the time just prior to a report's due date. The EPA is providing these potential extensions to protect owners and operators from noncompliance in cases where they cannot successfully submit a report by the reporting deadline for reasons outside of their control. The decision to accept the claim of needing additional time to report is within the discretion of the Administrator.

Electronic reporting is required in the amended 2016 NSPS OOOOa, and the EPA believes that the electronic submittal of these reports in the proposed NSPS OOOOb will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability, will further assist in the protection of public health and the environment, and will ultimately result in less burden on the regulated community. Electronic reporting can also eliminate paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, the EPA, and the public. Moreover, electronic reporting is consistent with the EPA's plan [212] to implement E.O. 13563 and is in keeping with the EPA's agency-wide policy [213] developed in response to the White House's Digital Government Strategy.[214]

In addition to the annual and semiannual reporting requirement, the EPA is soliciting comment on what elements, if any, are appropriate for more frequent reporting, and what mechanism would be appropriate for the collection and public dissemination of this information. For example, it may be appropriate to make information related to large emission events public in a timelier manner than the annual reporting period. Therefore, the EPA is soliciting comment on the appropriate mechanism to use for this type of report, including how the data would be reported, who would manage that reporting system, the frequency at which the data should be reported, the potential benefits of more frequent reporting for reducing emissions, the associated burden with this type of reporting and ways to mitigate that burden, and other considerations that should be taken into account.

N. Prevention of Significant Deterioration and Title V Permitting

The pollutant we are proposing to regulate is GHGs, not methane as a separately regulated pollutant. As explained in section XV of this preamble, we are proposing to add provisions to NSPS OOOOb and EG OOOOc, analogous to what was included in the 2016 NSPS OOOOa and other rules regulating GHGs from electric utility generating units, to make clear in the regulatory text that the pollutant regulated by this rule is GHGs. The proposed addition of these and other provisions is intended to address some of the potential implications on the CAA Prevention of Significant Deterioration (PSD) preconstruction permit program and the CAA title V operating permit program.

XII. Rationale for Proposed NSPS OOOOb and EG OOOOc

The following sections provide the EPA's BSER analyses and the resulting proposed NSPS to reduce methane and VOC emissions and the resulting proposed EG, which include presumptive standards, to reduce methane emissions from across the Crude Oil and Natural Gas source category. Our general process for evaluating BSER for the emission sources discussed below included: (1) Identification of available control measures; (2) evaluation of these measures to determine emission reductions achieved, associated costs, non-air environmental impacts, energy impacts and any limitations to their application; and (3) selection of the control techniques that represent

[211] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

[212] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: *https://www.regulations.gov/document?D=EPA-HQ-OA-2011-0156-0154.*

[213] E-Reporting Policy Statement for EPA Regulations, September 2013. Available at: *https://www.epa.gov/sites/production/files/2016-03/documents/epa-ereporting-policy-statement-2013-09-30.pdf.*

[214] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: *https://obamawhitehouse.archives.gov/sites/default/files/omb/egov/digital-government/digital-government.html.*

BSER.[215] As discussed in the 2016 NSPS OOOOa, the available control technologies will reduce both methane and VOC emissions at the same time. The revised BSER analysis we have undertaken for the sources addressed in the proposed NSPS OOOOb continues to support this conclusion. CAA Section 111 also requires the consideration of cost in determining BSER. Section IX describes how the EPA evaluates the cost of control for purposes of this rulemaking. Sections XII.A through XII.I provide the BSER analysis and the resulting proposed NSPS and EG for the individual emission sources contemplated in this action. Please note that there are minor differences in some values presented in various documents supporting this action. This is because some calculations have been performed independently (*e.g.,* NSPS OOOOb and EG OOOOc TSD calculations for NSPS OOOOb and EG OOOOc focused on unit-level cost-effectiveness and RIA calculations focused on national impacts) and include slightly different rounding of intermediate values.

For this proposed EG the EPA is proposing to translate the degree of emission limitation achievable through application of the BSER (*i.e.,* level of stringency) into presumptive standards.[216] As discussed in each of the EG-specific subsections below, the EPA's evaluation of BSER in the context of existing sources utilized much of the same information as our BSER analysis for the NSPS. This is because within the oil and natural gas industry many of the control measures that are available to reduce emissions of methane from existing sources are the same as those control measures available to reduce VOC and methane emissions from new, modified, and reconstructed sources. By extension, many of the methane emission reductions achieved by the available control options, as well as the associated costs, non-air environmental impacts, energy impacts, and limitations to their application, are very similar if not the same for new and existing sources. Any relevant differences between new and existing sources in the context of available control measures or any other factors are discussed in the EG-specific subsections below.

Where the EPA identified relevant distinctions between new and existing sources in the context of evaluating BSER, it was typically regarding the cost of control options. While many factors can cause differences in the cost of control between new and existing sources, the EPA would like to highlight two general concepts to illustrate how the oil and natural gas industry is unique. These concepts are the ''size'' of the affected facility and the type of standards. First, affected facilities defined in any given NSPS can range from entire process units to individual pieces of equipment. For affected facilities comprised of an entire process unit, or very large processes or equipment, there can be significant differences between the cost of construction or modification for a new source as compared to the cost of a retrofit required for implementation of a control at an existing source. In the case of a new sources, there can be cost savings associated with the up-front planning for the installation of controls which cannot be achieved at existing sources that must instead retrofit already existing processes or equipment. This is particularly true of controls involving equipment changes or add-on control devices. In contrast, most affected facilities for which the EPA is proposing standards in NSPS OOOOb are more narrowly defined. For example, a pneumatic controller affected facility is generally defined as a single natural gas-driven pneumatic controller, which is a discrete and relatively small piece of equipment in a larger process. Another example is the reciprocating compressor affected facility which is defined as a single reciprocating compressor. As such, the EPA did not identify the same type of cost savings associated with the up-front planning of controls in the oil and gas sector as we might in the context of larger affected facilities. We believe this is one factor that led to costs being very similar for new and existing sources.

Second, with regard to the type of standards, many of the standards proposed for NSPS OOOOb, and the presumptive standards proposed for EG OOOOc, are non-numerical standards, such as work practice standards, that require limited or no significant physical modifications. The EPA found that costs for these non-numerical standards would typically not differ between new and existing sources because the work practice could be implemented in both contexts without the need to first install or retrofit any equipment. Put another way, a work practice tends to operate in the same manner regardless of whether the site is new or existing, and existing sites typically do not need to take any preliminary steps in order to implement the work practice. For these reasons, many of the proposed presumptive standards for EG OOOOc discussed in the following sections mirror the proposed standards identified based on the BSER analyses for NSPS OOOOb.

A. Proposed Standards for Fugitive Emissions From Well Sites and Compressor Stations

1. NSPS OOOOb

There are many potential sources of fugitive emissions throughout the Crude Oil and Natural Gas Production source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated pressure relief valves (PRVs) or worn gaskets and springs on thief hatches on controlled storage vessels are also potential causes of fugitive emissions. Additional sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines, PRDs such as PRVs, pump seals, valves or controlled liquid storage tanks.

In the 2021 GHGI, the methane emissions for 2019 from fugitive emissions in the Crude Oil and Natural Gas source category were 96,000 metric tons methane for petroleum systems and 351,500 metric tons for natural gas systems. These levels represent 6 percent of the total methane emissions estimated from all petroleum systems sources (*i.e.,* exploration through refining) and 5 percent of all methane emissions from natural gas systems (*i.e.,* exploration through distribution). In addition, fugitive emissions may be represented in other categories of the GHGI production segment; for example, a portion of fugitive emissions (as defined in this action) is also expected to be related to fugitive emissions from tank thief hatches, and thief hatches on controlled storage vessels, and those emissions are included in the emissions estimates for storage vessels in the GHGI.

In the 2016 NSPS OOOOa, the EPA promulgated standards to control GHGs (in the form of limitations on methane emissions) and VOC emissions from fugitive emissions components located at well sites and compressor stations. These standards required a fugitive

[215] In the context of developing the draft emissions guidelines contained herein, this general process also follows, and is intended to satisfy, certain requirements of EPA's implementing regulations for CAA section 111(d), namely the specific listed component of a draft EG contained in 40 CFR 60.22a(b)(2), and some elements of paragraph (b)(3).

[216] This is intended to satisfy certain elements of the requirements of EPA's implementing regulations found at 40 CFR 60.22a(b)(3) and (5) with the exception of compliance times which the EPA discusses separately in section XVI.

emissions monitoring and repair program, where well sites and compressor stations had to be monitored semiannually and quarterly, respectively.

a. Fugitive Emissions From Well Sites

Oil and natural gas production practices and equipment vary from well site to well site. A well site can serve one well or multiple wells. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads with a number of operations such as production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate). In addition, the 2016 NSPS OOOOa definition of well site also includes centralized tank batteries for purposes of the fugitive emissions requirements because, like storage vessels at well sites, centralized tank batteries collect crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells; therefore, ''excluding tank batteries not located at the well site could incentivize some owners or operators to place new tank batteries further away from well sites to make use of such an exemption.'' [217] The equipment to perform these production operations (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) has components that may be sources of fugitive emissions. Therefore, the number of components with the potential for fugitive emissions can vary depending on the number of wells and the number of major production and processing equipment at the site. Another factor that impacts the operations at a well site, and the resulting fugitive emissions potential, is the nature of the oil and natural gas being extracted. This can range from well sites that only extract and handle ''dry'' natural gas to those that extract and handle heavy oil.

In both the 2016 NSPS OOOOa and subsequent amendments in the 2020 Technical Rule, the EPA relied on a model plant approach to estimate emissions from well sites. Model plants were developed to provide a representation of well sites across the spectrum. Separate production-based model plants using component counts to determine baseline emissions were developed. The basic approach used was to assign a number of specific equipment types for each well site model plant and then to estimate the number of components based on assigned numbers of components per equipment type. Primarily, the well site model plants utilized information from the DrillingInfo HPDI® database,[218] the 1996 EPA/GRI Study,[219] EPA's GHG Inventory, and GHGRP subpart W. Fugitive model plants were originally developed for the 2015 NSPS OOOOa proposed rule (80 FR 56614, September 18, 2015) and evolved over time in response to new information and public comments. More information on the history of the model plant development can be found in the 2015 NSPS Proposal TSD,[220] the 2016 NSPS Final TSD,[221] the 2018 NSPS Proposal TSD,[222] and the 2020 NSPS Final TSD.[223]

In this proposal, the EPA is shifting away from using model plants for well sites for the BSER analysis and is instead using an individual site-level emission-calculation approach in order to better characterize and take into account the differences at individual well sites that can lead to a vast range in the magnitude of fugitive emissions, which a model plant cannot do. Provided below is a more detailed explanation of the issues concerning the previous model plant approach, followed by a description of the site-specific baseline emission calculation approach, which is similar to the State of Colorado's LDAR program.

In the 2020 Technical Rule, the EPA created separate model plants to represent fugitive emissions from low production well sites (those producing 15 boe or less per day) and non-low production well sites, as it was generally assumed that low producing sites would have fewer major production and processing equipment and thus lower fugitive emissions. This prior estimate of baseline emissions was calculated using model plant site designs with assumed populations of major production and processing equipment and fixed fugitive emissions component counts. While the estimated baseline emissions from the two model plants differ due to the difference in the assumed populations of major production and processing equipment and fixed fugitive emissions component counts, the estimated baseline emissions were intended to represent the baseline emissions for all well sites represented by each model plant. Since that rulemaking, further analysis of existing and new information indicates that there is significant variation in the well characteristics, type of oil and gas products and production levels, gas composition, operations, and types and quantity of equipment at well sites across the U.S. The TSD for this action further describes existing data and new information received since the 2020 Technical Rule that have been evaluated by the EPA to arrive at the conclusion that there is no one-size-fits-all approach to predicting emissions from well sites and that the emissions vary greatly, in ways that bear little correlation to production levels alone. For example, site-level methane emissions data from comprehensive studies sampled across several different regions at numerous well sites, shows a wide range of methane emissions (*i.e.,* ranging from as low as 0 to as high as 1,200 tpy for marginal or low production wells). Additionally, recently obtained ICR data indicate that actual component counts at well sites with equipment could be higher than those estimated by model plants for low and non-low production, *e.g.,* EPA's non-low model plant could be underestimating number of wells, tanks and separators; and similar observations were made for low production based on this data. Contrary to previous general assumptions, information reviewed also shows that it is not necessarily the case that fugitive emissions from sites with lower production have lower emissions than sites with higher production. In fact, it is quite possible that the inverse can be true (*i.e.,* lower producing sites could have higher emissions and inversely, higher producing sites could have lower emissions.) More information can be found in the NSPS OOOOb and EG TSD for this proposal.

Therefore, the EPA has concluded that the previous model plant approach, which was based on two production levels (equal/above or below 15 boe per day) and the estimated equipment types and numbers associated with each of the two production levels, may not be reflective of the actual baseline fugitive emissions from well sites. Further, the potential for fugitive emissions at any given site is impacted more by the number and type of equipment at the site and maintenance practices, which can vary widely among well sites with low production.[224] Given these

[217] See Document ID No. EPA–HQ–OAR–2010–0505–7632 at page 4–221.

[218] Drilling Information, Inc. 2014. *DI Desktop.* 2014 Production Information Database.

[219] Gas Research Institute (GRI)/U.S. EPA. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* June 1996 (EPA–600/R–96–080h).

[220] EPA–HQ–OAR–2010–0505–5021.

[221] EPA–HQ–OAR–2010–0505–7631.

[222] EPA–HQ–OAR–2017–0483–0040.

[223] EPA–HQ–OAR–2017–0483–2290.

[224] See *https://pubs.acs.org/doi/10.1021/acs.est.0c02927, https://data.permianmap.org/*

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limitations in utilizing model plants to analyze fugitive emission reduction programs at well sites with widely varying configurations, operations, and production levels, we find it appropriate to shift away from using model plants and instead rely on the potential fugitive emissions at the individual site in our BSER analysis and resulting proposed standards. Therefore, this new analysis, which is described below, is conducted on this basis.

This site-specific baseline emissions calculation approach is similar to the State of Colorado's LDAR program. The concept is that each site calculates its baseline methane emissions for all the equipment at the site, the number and type of equipment at the well site, the number of fugitive emissions components associated with each piece of equipment, and the site-specific gas composition. The fugitive monitoring frequency would be based on the baseline site-specific methane emissions level calculated based on this information. This calculation is described in detail in section XI.A.2. We believe that this approach will more accurately depict the emissions profile at each individual well site. As a result, the EPA is conducting the BSER analysis based on site-level baseline methane emissions, where the analysis is performed in increments of 1 tpy of site-level baseline methane emissions as discussed more below.

During the rulemaking for the 2016 NSPS OOOOa, the EPA analyzed two options for reducing fugitive methane and VOC emissions at well sites: A fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs and a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Finding that both methods achieve comparable emission reduction but OGI was more cost effective, the EPA ultimately identified semiannual monitoring of well sites using OGI as the BSER. 81 FR 35856 (June 3, 2016). While there are several new fugitive emissions technologies under development, the EPA needs additional information to fully characterize the cost, availability, and capabilities of these technologies, and they are therefore not being evaluated as potential BSER at this time. However, we are proposing the use of these technologies as an alternative screening method as described in section XI.A.5. For this analysis for both the NSPS and the EG, we re-evaluated the use of OGI as BSER. In the discussion below, we evaluate OGI control options based on varying the frequency of conducting the survey and fugitive emissions repair threshold (*i.e.,* the visible identification of methane or VOC when an OGI instrument is used). For this analysis, we considered biennial, annual, semiannual, quarterly, and monthly survey frequency for well sites.

The regulatory concept for the proposed NSPS OOOOb is that the required frequency of fugitive monitoring would be based on total site baseline methane emissions. At well sites, the composition of gas is predominantly methane (approximately 70 percent on average). Therefore, as shown in our analysis, compared to VOC, methane better reflects the baseline emission level where it is cost effective to regulate both methane and VOC fugitive emissions at well sites. For this reason, we chose to use methane as the threshold for our determination.

For the BSER analyses, we selected for evaluation total site-wide methane emissions increments of 1 tpy of site-level baseline methane emissions ranging from 1 tpy to 50 tpy. The EPA acknowledges that the site-level baseline methane emissions calculated may not account for the presence of large emission events when they occur. However, the EPA has found it inappropriate to apply a factor that assumes every site is experiencing a large emission event annually based on information suggesting that only a small percentage of sites experience these events at any given time.[225]

In 2015, we evaluated the potential emission reductions from the implementation of an OGI monitoring program where we assigned an emission reduction of 40, 60, and 80 percent to annual, semiannual, and quarterly monitoring survey frequencies, respectively. The EPA re-evaluated the control efficiencies under different monitoring frequencies for the 2020 Technical Rule based on comments received on the 2018 proposal and concluded that the assigned control efficiencies described above can be expected from the corresponding monitoring frequencies using OGI.[226] No other information reviewed since that time indicates that the assigned reduction frequencies are different than previously established and the reduction efficiencies are consistent with what current information indicates. In addition, we also evaluated biennial survey frequency for well sites assuming an achievable reduction frequency of 30 percent, and monthly monitoring where information evaluated indicated monthly OGI monitoring has the potential of reducing emissions up towards 90 percent.

It is worth noting that these calculations are based on the expected reductions from ''typical'' component equipment leaks that occur with well-maintained sites. The EPA is aware of situations where equipment malfunctions related to equipment components can cause large emission events that are described in detail in section XII.A.5. In these cases, we expect the emission reductions associated with the different monitoring frequencies evaluated would be significantly higher than assumed above and is the reason we solicit comment on the proposed alternative screening program using advanced measurement technologies to identify and quantify large emission sources. Given the intermittent and stochastic nature of large emission events, it is difficult to apply emission factors that predict the probability of a site experiencing these events within any timeframe. As stated above, the EPA finds it inappropriate to apply a factor that assumes every site is experiencing a large emission event annually given the available data. However, we recognize that identifying and stopping these large emission events is a central purpose of the monitoring requirements proposed in this document, and that quantifying the pollution reduction benefits associated with addressing these large emission events is important to fully capture the benefits and cost-effectiveness of our proposed fugitive emissions monitoring requirements. We also acknowledge there is substantial ongoing research on large emission events that may further inform the EPA's calculations, including the potential to develop factors that take into account a distribution of emissions across well sites and the associated emissions reductions achieved when large emission events are included in the calculation.

We evaluated the costs of a monitoring and repair program under various monitoring frequencies. For

pages/flaring, and *https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf.*

[225] Brandt, A.R., Heath, G.A., Cooley, D. (2016). *Methane Leaks from Natural Gas Systems Follow Extreme Distributions.* Environ. Sci. Technol. 50, 12512, *https://pubs.acs.org/doi/abs/10.1021/acs.est.6b04303;* Zavala-Araiza, D., Alvarez, R., Lyon, D, et al. (2016). *Super-emitters in natural gas infrastructure are caused by abnormal process conditions.* Nat Commun 8, 14012 (2017). *https://www.nature.com/articles/ncomms14012;* Zavala-Araiza, D., Lyon, D., Alvarez, R. et al. (2015). PNAS 112, 15597. *https://www.pnas.org/content/112/51/15597.*

[226] See 85 FR 57412 and section 2.4.1.1 of the 2020 TSD.

well sites, the capital costs associated with the fugitives monitoring program were estimated to be $1,030 per well site. These capital costs include the cost of developing the fugitive emissions monitoring plan and purchasing or developing a recordkeeping data management system specific to fugitive emissions monitoring and repair. Consistent with the analyses used for the 2016 NSPS OOOOa and 2020 Technical Rule, the EPA assumes that each company will develop a monitoring plan and recordkeeping system that covers a company-defined area, which is assumed to include 22 well sites. This assumption is used because there are several elements of the fugitive monitoring program that are not site-specific. The total company-defined area (22 well site) capital costs are divided evenly to arrive at the $1,030 capital cost per well site estimate.

When evaluating the annual costs of the fugitive emissions monitoring and repair requirements (*i.e.,* monitoring, repair, repair verification, data management licensing fees, recordkeeping, and reporting), the EPA considers costs at the individual site level. Estimates for these costs were updated extensively as part of the 2020 Technical Rule, and the EPA has made further updates for this proposal based on more recent information. With these updates, the estimated annual costs of the fugitive emissions program at well sites are estimated to range from $2,490 for biennial monitoring to $8,140 for monthly monitoring.[227] These total annual costs include annualization of the up-front cost at 7 percent interest rate over 8 years. We note these costs are representative of the average annual costs expected at well sites, where larger sites may have larger costs associated with longer surveys or potentially more repairs, while smaller sites may experience the opposite with shorter surveys or potentially less repairs. Therefore, we believe the costs developed for well sites are representative of OGI fugitives monitoring program costs and reflect the best information available at this time.

The EPA requests comment on its range of cost estimates for an OGI fugitives monitoring program. The EPA believes that there will be sufficient supply of OGI equipment and available OGI camera operators for industry to conduct all required monitoring, upon the effective date of the NSPS OOOOb and the subsequent implementation of the EG OOOOc. However, the EPA requests additional information on this capacity and whether there is a likelihood of shortages in the early years of the program that might raise costs. The EPA is also requesting comment on the proposed appendix K and whether the proposed training, certification, and audit provisions are appropriate and do not place undue burden on the ability of industry to satisfy the regulatory requirements.

At well sites, there are savings associated with the gas not being released. The value of the natural gas saved is assumed to be $3.13 per Mcf of recovered gas. Annual costs were also calculated considering these savings.

As discussed in section XI.C, natural gas-driven intermittent pneumatic controllers are designed to vent during actuation only, but these devices are known to malfunction and operate incorrectly, which causes them to release natural gas to the atmosphere when idle. The EPA is proposing a zero VOC and methane emissions standard for natural gas-driven intermittent pneumatic controllers. However, for sites in Alaska located in the production segment (well sites, gathering and boosting stations, and centralized tank batteries) and in the transmission and storage segment that do not have electricity, the EPA is proposing a standard wherein intermittent natural gas-driven pneumatic controllers only vent during actuation and not when idle. See section XII.C on pneumatic controllers for a full explanation of this standard. While these intermittent controllers are their own separate affected facility, we are proposing that they be monitored in conjunction with the fugitive emissions components located at the same well site to verify proper actuation and that venting does not occur during idle times.

We created a matrix that includes, for each site-wide methane emission level, the capital (up front) cost, annual costs (with and without the consideration of savings), emission reductions for methane and VOC, and cost effectiveness (dollar per tons of emission reduction). Cost effectiveness was calculated using two approaches; the single pollutant approach where all the costs are assigned to the reduction of one pollutant; and the multipollutant approach, where half the costs are assigned to the methane reduction and half to the VOC reduction, see discussion in preamble section IX. This was repeated for each site-wide methane emissions level for each monitoring frequency. There were several trends shown in this matrix. As noted above, the annual cost for each individual monitoring frequency is applied to all site-wide emission levels when evaluating that frequency. Therefore, as the emissions (and potential emission reductions) increased, the fugitive emissions monitoring became more cost-effective. For example, for semiannual monitoring, the cost effectiveness ranged from $5,300 per ton of methane reduced (for a 1 tpy site-wide methane site) to $100 per ton (for a 50 tpy site-wide methane site). Also, because the emission reduction increase was greater than the cost increase with increasing monitoring frequency, the fugitive emissions monitoring became more cost-effective with increasing monitoring frequency. For example, for a 10 tpy site-wide methane site, the methane cost effectiveness for annual monitoring was $750 per ton, $530 per ton for semiannual monitoring, and $525 per ton for quarterly monitoring. This trend did not extend to monthly monitoring, as the cost of monthly monitoring increases significantly (almost double) compared to quarterly monitoring, while the emission reduction only increased by 10 percent. The complete matrix is available in the NSPS OOOOb and EG TSD for this rulemaking.

The matrix shows that, on a multipollutant basis, both semiannual and quarterly monitoring at well sites with baseline emissions as low as 2 tpy is cost-effective, and that at 3 tpy, both semiannual and quarterly monitoring are cost-effective based on the methane emissions alone. Cost-effectiveness, however, is not the only relevant factor in setting the BSER, particularly for a source as numerous and diverse as well sites. We estimate that there will be approximately 21,000 new wells each year (and 410,000 existing wells) to which the proposed fugitive emissions requirements will apply.[228] Various studies demonstrate that the vast majority of emissions come from a relatively small subset of wells.[229] [230]

[227] As a comparison, the annualized costs for fugitive emissions monitoring and repair at well sites were estimated to range from $1,900 to $3,500 for annual to quarterly monitoring, respectively, in the 2020 Technical Rule. See 2020 TSD, attachment 5 at Document ID No. EPA–HQ–OAR–2017–0483–2290.

[228] Estimated well counts are based on non-wellhead only sites. Based on information provided by API, we assume that 27% of sites are wellhead only; see Memoranda for Meetings with the American Petroleum Institute (API), September 23, 2021, located at Docket ID No. EPA–HQ– OAR–2021–0317. Absent additional information, we also assume that 27% of wells are wellhead only. The estimated new well count reflects the arithmetic average of well counts over the analysis horizon in the RIA, 2023–2035. The estimated existing well count reflects the total in 2026, which is the first year that we estimate impacts for the emissions guidelines.

[229] Brandt, A., Heath, G., Cooley, D. (2016) *Methane leaks from natural gas systems follow*

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The EPA would like to ensure that resources and effort are focused on those wells that emit the most methane and VOC. Moreover, given the diversity of ownership, while our cost assumption that distributes the costs of recordkeeping evenly across 22 sites within a company-defined area is a reasonable estimate for the population as a whole, it may underestimate the costs and therefore overestimate the cost-effectiveness for owners with fewer than 22 well sites (and conversely, underestimate cost-effectiveness for owners with more than 22 well sites). In order to best focus resources and effort on the well sites with the greatest emissions and more accurately capture costs, particularly for owners with fewer well sites, the EPA requests comment on the number of wells that likely emit at each baseline emissions level, and the baseline emissions level of wells generally owned by owners with few wells. The EPA anticipates that it may refine its BSER determination for well sites through its supplemental proposal based on the information gathered from commenters.

Taking these factors into account, and as explained in more detail below, the EPA proposes to conclude that (1) BSER for well sites with a baseline site-wide emissions level of less than 3 tpy is no regular monitoring, but that to help ensure that these sites actually emit at less than 3 tpy, a one-time survey (following each calculation of site-level baseline methane emissions) would be required to ensure that any abnormalities are addressed; (2) BSER for well sites with a baseline site-wide emissions level of 3 tpy or greater is quarterly monitoring. Because of the uncertainties discussed above, and as explained in more detail below, the EPA further co-proposes to conclude that BSER for well sites with a baseline site-wide emissions level of 3 tpy or greater and less than 8 tpy is semiannual monitoring. Our co-proposal is the same as our main proposal with regard to well sites whose baseline site-wide emissions are less than 3 tpy (no regular monitoring, but a one-time survey) and whose emissions are 8 tpy or greater (quarterly monitoring). The EPA estimates that a majority of fugitive emissions (approximately 86%) can be attributed to wells with site-wide baseline emissions of 3 tpy or greater, where 54% can be attributed to wells with site-wide baseline emissions of 8 tpy or greater.[231]

Proposed BSER for Well Sites with Baseline Emissions Less Than 3 tpy. As noted, in both our main proposal and our co-proposal, we propose to conclude that BSER for well sites with baseline emissions of less than 3 tpy is no regular monitoring, but a one-time survey to help ensure that these sites actually emit at less than 3 tpy.

Based on the matrix described above, the EPA determined that where total site baseline methane emissions are 2 tpy, semiannual and quarterly monitoring costs approximately $2,700/ton methane reduced, while biennial and annual monitoring costs approximately $4,000/ton methane reduced. The costs for VOC reductions range from $10,000 to $15,000/ton VOC reduced for quarterly to biennial monitoring, respectively. These costs are outside the range of what we are proposing to consider cost effective on a single-pollutant basis for both methane and VOC. See Section IX.B. However, when considered on a multipollutant basis, the costs of semiannual and quarterly monitoring are approximately $1,350 per ton methane reduced, and approximately $5,000 per ton of VOC, which we do consider cost-effective. Thus, for sites with total baseline methane emissions of 2 tpy, we conclude that regular monitoring at semiannual or quarterly frequencies would be cost-effective.[232]

We do not propose to conclude that routine monitoring with OGI is the BSER for sites with baseline emissions of less than 3 tpy, however, for several reasons. While the estimates for semiannual and quarterly monitoring are within what we consider to be cost effective for well sites with baseline emissions of 2 tpy, in light of the large cohort of relatively lower-emitting sites, we are concerned that our cost effectiveness estimates may not accurately capture the costs, and therefore cost-effectiveness, of routine monitoring with OGI for businesses that own relatively few well sites. Throughout the development of the 2016 NSPS OOOOa, and in subsequent analyses and rulemaking actions, industry stakeholders have consistently stated that the fugitive monitoring requirements are particularly burdensome for smaller entities that own fewer well sites. The EPA believes that many of these smaller entities are likely to own well sites with baseline emissions of less than 3 tpy, a category that tends to include smaller and less complex facilities with few or no major pieces of production and processing equipment.[233] And as noted, the EPA would like to ensure that resources and effort are focused on well sites with significant emissions. Given the possibility that our cost-effectiveness analysis has overestimated the average number of sites, and therefore underestimated the cost-effectiveness, for this cohort of well sites, the EPA is proposing no regular monitoring at sites with baseline site-wide emissions of less than 3 tpy.

While the EPA is proposing to conclude that BSER for well sites with total site-level baseline methane emissions less than 3 tpy is no regular monitoring, we believe it is essential to ensure that well sites in this monitoring tier are operating in a well-controlled manner, and are not experiencing leaks or malfunctions that would cause their emissions to exceed 3 tpy. Therefore, the EPA is proposing a requirement for owners and operators to conduct a survey, and perform repairs as needed, to demonstrate that the well site is free of leaks or malfunctions and is therefore operating in a manner consistent with the baseline methane emissions calculation.[234] This survey could employ any method available that would demonstrate the actual emissions are consistent with the baseline calculation, including, but not limited to, the use of OGI, EPA Method 21 (which includes provisions for a soap bubble test), or alternative methane detection technologies like those discussed in the proposed screening alternative in section XI.A.5.

The EPA seeks comment on all aspects of this proposed BSER determination, including information, data, and analysis that would shed further light on the factors and concerns just expressed and that would support the establishment of ongoing monitoring requirements at the cohort of sites with baseline methane emissions below 3 tpy. Among other things, the EPA seeks

extreme distributions. Environ. Sci. Technol., DOI: 10.1021/acs.est.6b04303.

[230] Zavala-Araiza, D., Alvarez, R., Lyon, D, et al. (2016). *Super-emitters in natural gas infrastructure are caused by abnormal process conditions.* Nat Commun 8, 14012 (2017). *https://www.nature.com/articles/ncomms14012.*

[231] Percentages were estimated for the baseline scenario in the RIA for the 2030 analysis year by combining the bin percentages presented in RIA Table 2–4 with the projected well site activity data documented in the RIA.

[232] The NSPS OOOOb and EG OOOOc TSD also provide costs for monitoring at 1 tpy, which is not considered cost-effective at any frequency evaluated.

[233] Anna M. Robertson, Rachel Edie, Robert A. Field, David Lyon, Renee McVay, Mark Omara, Daniel Zavala-Araiza, and Shane M. Murphy. ''New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates.''

Environmental Science & Technology 2020 *54* (21), 13926–13934. DOI: 10.1021/acs.est.0c02927.

[234] We anticipate that during the survey to confirm their baseline methane emissions and thus exemption status, sources would also repair the leaks found, consistent with our understanding of the standard industry practice.

comment on the ownership profile of well sites with site-wide baseline emissions less than 3 tpy, the extent to which well sites in this cohort are owned by firms that own relatively few wells, and the relative economic costs associated with requiring regular OGI monitoring at these wells. The EPA also seeks information that would improve our understanding of the overall number of wells that would fall in this cohort of sites, and the contribution these wells make to overall fugitive emissions. And the EPA seeks comment on our estimates of the costs and emission reduction associated with OGI monitoring at this cohort of sites, or other data and analysis that would provide support for regular OGI monitoring at these sites. In addition, the EPA notes that the advanced measurement technologies that form the basis of our proposed alternative screening option in section XI.A.5 could be particularly well-suited for rapidly and cost-effectively detecting recurrences of large emitting events at sites with baseline emissions below 3 tpy. Accordingly, the EPA seeks comment that could inform whether to require the use of these technologies for ongoing monitoring at this cohort of sites, including information on the capabilities of these emerging technologies, methodologies for their use, and the costs and emission reductions associated with using these advanced measurement technologies as part of a mandatory monitoring regime. If appropriate, and based on input received during the comment period, the EPA may consider further addressing monitoring requirements for sites with baseline emissions below 3 tpy as part of a supplemental proposal.

Additionally, the EPA is soliciting comment on different criteria, such as the number of well sites owned by a specific owner, that could better account for factors that may affect the costs of fugitive emissions monitoring. As noted, while the EPA has presented costs on an individual site-level, we have also distributed the costs of recordkeeping evenly across an assumed 22 sites within a company-defined area. While this may be appropriate for companies with larger ownership, it is likely underestimating the cost (and overestimating the cost-effectiveness) on owners with fewer sites. Information provided on small businesses, including ownership thresholds, could be used to further determine differences in OGI monitoring requirements at well sites through a supplemental proposal.

Further, the EPA is soliciting comment on whether the presence of specific major production and processing equipment types at a well site warrants a separate monitoring frequency consideration even where the calculated total site-level baseline methane emissions are below 3 tpy. As mentioned throughout this preamble, the EPA is concerned about the presence of large emission events, which various studies have shown are most often attributed to specific equipment. This equipment includes separators paired with onsite storage vessels, combustion devices, and intermittent pneumatic controllers.[235] [236] [237] Therefore, the EPA is soliciting comment on whether well sites with these specific types of equipment present must conduct at least semiannual monitoring, regardless of the total site-level baseline methane emissions calculated, including those sites calculated below 3 tpy.

Finally, the EPA believes there is a subset of well sites (*i.e.,* wellhead only well sites) that will never have baseline methane fugitive emissions of 3 tpy or greater. Therefore, the proposed rule would not define these sites as affected facilities, thus removing the need for these sites to determine baseline emissions. As defined in the 2020 Technical Rule, a ''wellhead only well site'' is ''a well site that contains one or more wellheads and no major production and processing equipment.'' The term ''major production and processing equipment'' is defined as including reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water. As described earlier in this section, sites will calculate their baseline methane emissions using a combination of population-based emission factors and storage vessel emissions. The population-based emission factors include emissions from wellheads, reciprocating and centrifugal compressors, glycol dehydrators, heater/treaters, separators, natural gas-driven pneumatic pumps, and natural gas-driven pneumatic controllers (both continuous and intermittent). By definition, a wellhead only well site would not have emissions associated with the major production and processing equipment, which includes storage vessels. Further, this proposed rule would not allow the use of natural gas-driven pneumatic controllers at any location (except on the Alaska North Slope), including wellhead only well sites. Therefore, the only emissions would be calculated based on the fugitive emissions components associated with the wellhead, which we believe would never be above 3 tpy.

Proposed BSER for Sites with Baseline Emissions of 3 tpy or Greater. The EPA next evaluated what frequency of OGI monitoring is BSER for well sites where the total site-level baseline methane emissions are 3 tpy or greater. Table 14 summarizes the cost-effectiveness information for each monitoring frequency evaluated at this threshold.

TABLE 14—SUMMARY OF EMISSION REDUCTIONS AND COST–EFFECTIVENESS FOR SITE–LEVEL BASELINE METHANE EMISSIONS OF 3 TPY

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Single-pollutant		Multipollutant	
				Methane cost-effectiveness ($/ton)	VOC cost-effectiveness ($/ton)	Methane cost-effectiveness ($/ton)	VOC cost-effectiveness ($/ton)
3 tpy site-level baseline methaneemissions							
Biennial	$2,500	0.90	0.25	$2,800	$10,000	$1,400	$5,000
Annual	3,000	1.20	0.33	2,500	9,000	1,250	4,500
Semiannual	3,200	1.80	0.50	1,800	6,400	900	3,200
Quarterly	4,200	2.40	0.67	1,800	6,300	900	3,200
Monthly	8,100	2.70	0.75	3,000	11,000	1,500	5,400

[235] *Id.*

[236] Tyner, David R., Johnson, Matthew R., ''Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data.'' *Environmental Science & Technology* 2021 *55* (14), 9773–9783. DOI: 10.1021/acs.est.1c01572.

[237] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al.* Closing the methane gap in US oil and natural gas production emissions inventories. *Nat Commun* 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4.*

Based on the information summarized in Table 14, the average costs per ton reduced appear to be reasonable for either semiannual or quarterly monitoring when site-level baseline methane emissions are 3 tpy or greater under the single pollutant approach for methane (biennial, annual, or monthly are outside of what the EPA considers reasonable for VOCs in the single pollutant approach), or reasonable at any frequency under the multipollutant approach.

In addition to considering the average costs per ton reduced for these sites, the EPA also evaluated the incremental cost associated with progressing to greater monitoring frequencies. To conduct this analysis, the EPA first considered semiannual monitoring for these sites as a baseline for comparison. Since 2016, owners and operators have been conducting semiannual monitoring pursuant to NSPS OOOOa, State requirements, or voluntarily, thus demonstrating the reasonableness of that frequency. Additionally, the cost is comparable to the costs found reasonable in the 2016 NSPS OOOOa [238] for both the single pollutant approach for methane or multipollutant approach for both methane and VOC. To determine if quarterly monitoring is reasonable for sites with total baseline methane emissions of 3 tpy, we evaluated the incremental costs of going from semiannual to quarterly monitoring. The incremental costs of semiannual to quarterly monitoring for an emissions baseline of 3 tpy methane is $1,700/ton methane and $6,000/ton VOC using the single pollutant approach (and $800/ton methane and $3,000/ton VOC using the multipollutant cost effectiveness approach). These incremental costs are within the range we find reasonable in this proposal under the single pollutant approach for methane and under the multipollutant approach.

We next evaluated monthly monitoring for this cohort. As shown in Table 14, monthly monitoring appears reasonable under the multipollutant approach. Therefore, we evaluated the incremental costs of going from quarterly monitoring to monthly monitoring to determine if monthly monitoring is appropriate. Table 15 summarizes these incremental costs. As shown in Table 15, the incremental cost of going from quarterly to monthly monitoring when baseline emissions are 3 tpy is $13,000/ton methane and $47,000/ton VOC under the single pollutant approach ($6,500/ton methane and $23,500/ton VOC under the multipollutant approach). In both approaches, these costs are outside the range of what we are proposing to consider cost effective. See Section IX.B.

Based on the analysis described above, we propose to find that quarterly monitoring at well sites with total site-level baseline methane emissions of 3 tpy or greater is the BSER. We note that California requires quarterly inspections for all well sites under its LDAR requirements in Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Article Subarticle 13: *Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities,* which supports a conclusion that quarterly monitoring at these sites is feasible and cost-effective.[239]

Accordingly, the EPA's primary proposal is to conclude that BSER for well sites with total site-level baseline emissions of less than 3 tpy is no regular monitoring (but a one-time survey) and that BSER for well sites with total site-level baseline emissions of 3 tpy or greater is quarterly monitoring and repair.

While the EPA is proposing quarterly OGI monitoring for well sites with total site-level baseline methane emissions of 3 tpy or greater, we are concerned this cost-effectiveness analysis may not fully account for the numerosity and diversity of sites and their potential emission profiles. We further note that some States with established fugitive emissions monitoring programs have provided for more graduated frequencies that recognize this diversity among sites. For example, Colorado's Regulation 7 Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions [240] requires a tiered inspection frequency regime that provides for semiannual monitoring at site-wide baseline emissions thresholds that far exceed the EPA's proposed 3 tpy threshold. Under the Colorado regulations, a semiannual inspection frequency is required for well production facilities with uncontrolled actual VOC emissions between 2 and 12 tpy (corresponding to approximately 7 to 43 tpy methane). Quarterly inspections are required for well sites without storage tanks and with uncontrolled actual VOC emissions between 12 and 20 tpy (corresponding to approximately 43 to 72 tpy methane), and for well sites with storage tanks and with uncontrolled actual VOC emissions between 12 and 50 tpy (corresponding to approximately 43 to 180 tpy methane). Colorado Regulation 7 also requires monthly inspections for well production facilities without storage tanks with uncontrolled actual VOC emissions above 20 tpy (and above 50 tpy for facilities with storage tanks). The proposed thresholds for quarterly monitoring in this action are more stringent than the Colorado regulations when compared using the gas composition ratio of 0.28 VOC to methane that is used in our BSER analysis. Specifically, the VOC emissions associated with a site-level baseline methane emission rate of 3 tpy are 0.83 tpy VOC, less than half the VOC threshold that requires semiannual monitoring and 14.5 times lower than the VOC threshold requiring quarterly monitoring in Colorado.

Although Colorado's regulations are most directly comparable to the EPA's proposed approach, other States also provide for more graduated monitoring frequencies. For example, Ohio's General Permits 12.1 and 12.2 initially require quarterly monitoring for well sites, followed by a reduced monitoring frequency of semiannual or annual monitoring depending on the fraction of equipment found to be leaking.[241]

When considering these State programs, particularly the comparison of our proposal to Colorado's thresholds; the fact that our cost-effectiveness calculation may not account for the diversity of emissions and sites; and the concerns we have raised regarding the cost-effectiveness for businesses with fewer well sites than are assumed in our cost-effectiveness analysis (many of whom we anticipate are small businesses), the EPA believes it is also appropriate to co-propose semiannual monitoring for well sites in a middle cohort—those with total site-level baseline emissions of 3 tpy or greater and less than 8 tpy. We seek comment on the number and ownership profile of wells that would fall into this category to better understand whether semiannual monitoring is an appropriate monitoring frequency for sites in this range.

To inform this analysis, we evaluated methane emissions in 1 tpy increments starting at 3 tpy. Tables 15a and 15b summarize the total costs and incremental costs of semiannual to quarterly for baseline methane

[238] The 2020 Technical Rule amended only the VOC standards in the 2016 NSPS OOOOa and, as discussed in section X.A, incorrectly identified $738/ton as the highest value that the EPA found cost effective for methane reduction in the 2016 NSPS OOOOa.

[239] *https://ww2.arb.ca.gov/sites/default/files/classic/regact/2016/oilandgas2016/ogfro.pdf.*

[240] *https://cdphe.colorado.gov/aqcc-regulations.*

[241] *https://epa.ohio.gov/dapc/genpermit/oil-and-gas-well-site-production.*

emissions of 3 tpy or greater and less than 8 tpy.

TABLE 15A—SUMMARY OF TOTAL COST–EFFECTIVENESS FOR FUGITIVE MONITORING AT WELL SITES

Site-level baseline methane emissions (tpy)	Annual cost ($/yr/site)	Single pollutant cost-effectiveness		Multipollutant cost-effectiveness	
		Methane ($/ton)	VOC ($/ton)	Methane ($/ton)	VOC ($/ton)
Semiannual Monitoring					
3	$3,200	$1,800	$6,400	$890	$3,200
4	3,200	1,300	4,800	670	2,400
5	3,200	1,100	3,800	530	1,900
6	3,200	890	3,200	440	1,600
7	3,200	760	2,700	380	1,400
8	3,200	670	2,400	330	1,200
Quarterly Monitoring					
3	4,200	1,800	6,300	880	3,200
4	4,200	1,300	4,700	660	2,400
5	4,200	1,000	3,800	530	1,900
6	4,200	880	3,200	440	1,600
7	4,200	750	2,700	380	1,400
8	4,200	660	2,400	330	1,200

TABLE 15B—SUMMARY OF INCREMENTAL COST–EFFECTIVENESS FOR FUGITIVE MONITORING AT WELL SITES

Site-level baseline methane emissions (tpy)	Incremental annual cost ($/yr/site)	Incremental methane emission reduction (tpy/site)	Incremental VOC emission reduction (tpy/site)	Incremental cost-effectiveness	
				Methane ($/ton)	VOC ($/ton)
Incremental for semiannual to quarterly					
3	$1,000	0.60	0.17	$1,700	$6,000
4	1,000	0.80	0.22	1,250	4,500
5	1,000	1.00	0.27	1,000	3,600
6	1,000	1.20	0.33	840	3,000
7	1,000	1.40	0.39	720	2,600
8	1,000	1.60	0.45	630	2,250

While there is no obvious cutoff point, the EPA anticipates that well sites with calculated baseline emissions of 8 tpy or greater will generally consist of complex sites comprising multiple wellheads and/or one or more of the major pieces of production or processing equipment that are known to have a propensity for causing large emissions events. The EPA also believes it is possible that at 8 tpy and greater, well sites are both more likely to be owned by companies with a larger number of sites and that the owners of these wells are likely to be larger companies. Lastly, the EPA estimates that a large share of fugitive emissions (approximately 54%) can be attributed to wells with site-wide baseline emissions of 8 tpy or greater.[242] For these reasons, the EPA believes that an 8 tpy threshold for quarterly monitoring would appropriately focus resources on the wells with the largest emissions profiles, and that concerns about on the costs for small owners or operators are most attenuated for this cohort of relatively large and high-emitting sites. As noted above, we seek comment on whether it is sensible to have a middle cohort with a semiannual monitoring requirement and, if so, what the bounds of that cohort should be. In making this determination, the EPA is particularly interested in comments regarding the number and ownership profiles of well sites that may fall into this middle cohort.

As required by section 111, the EPA's proposed BSER analysis for fugitive emissions from all well sites has considered nonair quality health and environmental impacts. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by contractors conducting the OGI camera monitoring associated with driving to and from the site for the fugitive emissions survey. Using AP–42 mobile emission factors and assuming a distance of 70 miles to the well site, the emissions generated from semiannual monitoring at a well site (140 miles to and from the well site twice a year) is estimated to be 0.35 lb/yr of hydrocarbons, 6.0 lb/yr of CO and 0.40 lb/yr of NO_x. No other secondary impacts are expected. We do not believe these secondary emissions are so significant as to affect the proposed determinations described above.

In summary, based on the analysis described above, the EPA is proposing OGI monitoring based on tiered total site-wide baseline methane emission levels to represent thresholds that would determine the monitoring frequency. For well sites with total site-level methane emissions less than 3 tpy,

[242] Percentage estimated using the analysis underpinning the baseline scenario in the RIA for the 2030 analysis year.

the EPA is proposing to require a one-time survey to demonstrate that the well site is free of leaks or other abnormal conditions that are not accounted for in the baseline calculation. For well sites with total site-level methane emissions of 3 tpy or greater, the EPA is proposing quarterly monitoring at all sites. Lastly, the EPA is co-proposing semiannual monitoring for well sites with total site-level methane emissions of 3 tpy or greater and less than 8 tpy, and quarterly monitoring for all sites with baseline emissions of 8 tpy or greater. As noted earlier, site-level baseline emission levels would be calculated by owners and operators for each site based on prescribed population emission factors for components and equipment at the site, combined with an assessment of potential methane emission from storage vessels (after applying controls).

b. Fugitive Emissions From Compressor Stations

The EPA continues to utilize the model plant approach in estimating baseline fugitive emissions from compressor stations. Unlike well sites, we believe that compressor station designs are less variable and that model plants are an effective construct to analyze fugitive emission control programs. The EPA has evaluated feedback received from several industry stakeholders related to development of compressor station model plants over multiple years since the original 2015 NSPS OOOOa proposal were model plants for compressor stations (including those at gathering and boosting stations, transmission stations, and storage facilities) were first introduced. Consistent with this early approach for estimating emissions from compressor stations, the EPA still believes the model plant approach is the best way to assess fugitive emissions from compressor stations, in the absence of information indicating otherwise. Baseline model plant emissions for compressor stations can reasonably be calculated using equipment counts, fugitive emissions component counts, and emissions factors from the 1995 Emissions Protocol. The EPA has evaluated each specific model plant for gathering and boosting, transmission, and storage, based on information that has become available, and model plants were updated where information indicated an update was appropriate. For example, information from actual compressor stations in operation provided by GPA Midstream for several of their member companies representing numerous sites across the country, was used to refine the gathering and boosting model plant in 2020. Refinements have also been made to the transmission and storage model plants based on information received from companies in these segments. The size and equipment located at compressor stations do not vary as widely as at well sites, and therefore emissions are expected to be less variable as well. Furthermore, stakeholders have not indicated that a model plant approach is not reasonable. For these reasons, the EPA retains a model plant approach for compressor stations which are representative in estimating fugitive emissions.

There are three types of compressor stations in the Crude Oil and Natural Gas source category: (1) Gathering and boosting stations, (2) transmission stations, and (3) storage stations. The equipment associated with these compressor stations vary depending on the volume of natural gas that is transported and whether any treatment of the gas occurs, such as the removal of water or hydrocarbons. The model plants developed for these sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) and associated components (*e.g.,* valves and connectors) that may be sources of fugitive emissions associated with these operations. One model plant was developed for each of the three types of compressor stations described above, which are discussed in detail in the 2020 NSPS OOOOa TSD and in the NSPS OOOOb and EG TSD supporting this action. For gathering and boosting stations, the fugitive baseline emissions were estimated to be 16.6 tpy of methane and 4.6 tpy of VOC. For transmission stations, the fugitive baseline emissions were estimated to be 40.4 tpy of methane and 1.1 tpy of VOC. For storage stations, the fugitive baseline emissions were estimated to be 142.2 tpy of methane and 3.9 tpy of VOC.

As with well sites, in the original BSER analysis for the 2016 NSPS OOOOa rulemaking, two options for reducing fugitive methane and VOC emissions at compressor stations were identified, which were (1) a fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs and (2) a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Finding that both methods achieve comparable emission reduction but OGI was more cost effective, the EPA ultimately identified quarterly monitoring of compressor stations using OGI as the BSER. 81 FR 35862. While there are several new fugitive emissions technologies under development, the EPA needs additional information and better understanding of these technologies, and they are therefore not being evaluated as potential BSER at this time. For this analysis for both the NSPS and the EG, we re-evaluated OGI as BSER. In the discussion below, we evaluate OGI control options based on varying the frequency of conducting the survey and fugitive emissions repair threshold (*i.e.,* the visible identification of methane or VOC when an OGI instrument is used). For this analysis, we considered annual, semiannual, quarterly, and monthly survey frequency for compressor stations.

In 2015, we evaluated the potential emission reductions from the implementation of an OGI monitoring program where an emission reduction of 40, 60 and 80 percent for annual, semiannual, and quarterly monitoring survey frequencies, respectively, were determined appropriate. No other information reviewed since 2015 indicates that the assigned reduction frequencies are different than previously established and the reduction efficiencies are consistent with what current information indicates. In addition, we also evaluated monthly monitoring for compressor stations where information evaluated indicated monthly OGI monitoring has the potential of reducing emissions up towards 90 percent.

We evaluated the costs of monitoring and repair under various monitoring frequencies described above, including the cost of OGI monitoring via the camera survey, repair costs, resurvey costs, monitoring plan development and the cost of a recordkeeping system. For compressor stations, the capital cost associated with the fugitives monitoring program were estimated to be $3,090 for each gathering and boosting compressor station, which includes development of a fugitive emissions monitoring plan for a company-defined area (assumed to include 7 gathering and boosting compressor stations) and database management development or licensing for recordkeeping. These capital costs are divided evenly amongst the 7 gathering and boosting compressor stations in the company-defined area for purposes of the model plant analysis, consistent with the 2016 NSPS OOOOa and 2020 Technical Rule analyses. The capital cost associated with the fugitives monitoring program for transmission and storage compressor stations was estimated at $23,880, which is for a single transmission and storage compressor station. The annual costs

include the capital recovery cost (calculated at a 7 percent interest rate for 10 years), survey and repair costs, database management fees, and recordkeeping and reporting costs. The annual costs estimated for compressor stations range from $6,350 for annual monitoring to $33,220 for monthly monitoring at gathering and boosting compressor stations. For transmission compressor stations, the annual costs estimated range from $12,900 for annual monitoring to $39,770 for monthly monitoring. For storage compressor stations, the annual costs estimated range from $17,000 for annual monitoring to $43,860 for monthly monitoring.

As discussed above, the EPA is proposing that natural gas-driven intermittent vent controllers at production and natural gas transmission sites in Alaska without electricity would be subject to a standard that prohibits emissions when the controller is idle. Intermittent pneumatic controllers are designed to vent during actuation only, but these devices are known to malfunction and operate incorrectly which causes them to release natural gas to the atmosphere when idle. For sites in Alaska that do not have electricity located in the production segment (well sites, gathering and boosting stations, and centralized tank batteries) and in the transmission and storage segment, the EPA is proposing to define intermittent natural gas-driven pneumatic controllers as an affected facility and proposing to apply a standard that these controllers only vent during actuation and not when idle. See section XII.C on pneumatic controllers for a full explanation of this standard. We have determined that it would be efficient and reasonable to verify proper actuation and that venting does not occur during idle times by proposing that these devices are monitored along with fugitive emissions components at a site to ensure these devices are meeting the standard. We believe the cost of monitoring of intermittent pneumatic controllers will be absorbed by the cost of the fugitive emissions program, and that little to no additional cost would be associated with monitoring these devices on the fugitive emissions components monitoring schedule. If compressor stations have electricity, they would be required to have non-emitting controllers, and no additional costs are expected to be incurred relayed to repair and/or replacement of malfunctioning intermittent vent controllers.

At gathering and boosting compressor stations there are savings associated with the gas not being released. The value of the natural gas saved is assumed to be $3.13 per Mcf of recovered gas. Transmission and storage compressor stations do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted/lost was not applied for this segment.

The EPA evaluated the cost-effectiveness of monitoring for each sub-type of compressor station, starting with evaluating whether quarterly monitoring remains the BSER. The 2016 NSPS OOOOa requires a fugitive emissions monitoring and repair program, where compressor stations have to be monitored quarterly. Compressor stations have successfully met this standard. Further, several State agencies have rules that require quarterly monitoring at compressor stations. For example, Colorado's Regulation 7 Control of Ozone via *Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions* [243] requires a semiannual inspection frequency for compressor stations with uncontrolled actual VOC emissions between 2 and 12 tpy, a quarterly inspection frequency for compressor stations with uncontrolled actual VOC emissions between 12 and 50 tpy, and monthly inspections for compressor stations with uncontrolled actual VOC emissions above 50 tpy. California requires quarterly inspections under their LDAR requirements [244] and similarly, Ohio's General Permit 18.1 also requires quarterly monitoring for compressor stations.[245] These examples of State rules, where quarterly monitoring appears to be the lowest monitoring frequency required with one exception where the VOC baseline emissions were extraordinarily high, is a demonstration of the reasonableness of monitoring fugitive emissions components on a quarterly basis for compressor stations.

Given the apparent reasonableness of quarterly monitoring as discussed above, the EPA evaluated whether it was reasonable to require monthly monitoring for compressor stations. Table 16 summarizes the cost, emission reductions, and cost-effectiveness of quarterly and monthly OGI monitoring at compressor stations for the single pollutant approach, while Table 17 summarizes the multi-pollutant approach.

TABLE 16—SUMMARY OF THE SINGLE POLLUTANT COST OF CONTROL FOR COMPRESSOR STATION FUGITIVE EMISSIONS MONITORING

Model plant	Capital cost ($)	Annual cost ($/yr)	Annual cost w/savings ($/yr)	Emission reductions		Methane cost of control w/o savings ($/ton)	VOC cost of control w/o savings ($/ton)
				Methane (tons/yr)	VOC (tons/yr)		
Quarterly Monitoring							
Gathering & Boosting	$3,100	$13,400	$11,000	13.3	3.7	$1,000	$3,600
Transmission	23,900	19,900	19,900	32.3	0.9	600	22,300
Storage	23,900	24,000	24,000	114.0	3.2	200	7,600
Compressor Program Weighted Average						900	4,400
Monthly Monitoring							
Gathering & Boosting	3,100	33,200	30,500	15.0	4.2	2,200	8,000
Transmission	23,900	39,800	39,800	36.4	1.0	1,100	39,500
Storage	23,900	43,900	43,900	128.2	3.5	340	12,400
Compressor Program Weighted Average						1,800	9,300

[243] *https://cdphe.colorado.gov/aqcc-regulations.*

[244] *https://ww2.arb.ca.gov/sites/default/files/classic/regact/2016/oilandgas2016/ogfro.pdf.*

[245] *https://www.epa.state.oh.us/dapc/genpermit/ngcs/GP_181.*

TABLE 17—SUMMARY OF THE MULTI–POLLUTANT COST OF CONTROL FOR COMPRESSOR STATION FUGITIVE EMISSIONS MONITORING

Model plant	Capital cost ($)	Annual cost ($/yr)	Annual cost w/savings ($/yr)	Emission reductions		Methane cost of control w/o savings ($/ton)	VOC Cost of control w/o savings ($/ton)
				Methane (tons/yr)	VOC (tons/yr)		
Quarterly Monitoring							
Gathering & Boosting	$3,100	$13,400	$11,000	13.3	3.7	$500	$1,800
Transmission	23,900	19,900	19,900	32.3	0.9	300	11,100
Storage	23,900	24,000	24,000	114.0	3.2	100	3,800
Compressor Program Weighted Average						430	2,200
Monthly Monitoring							
Gathering & Boosting	3,100	33,200	30,500	15.0	4.2	1,100	4,000
Transmission	23,900	39,800	39,800	36.4	1.0	550	19,800
Storage	23,900	43,900	43,900	128.2	3.5	200	6,200
Compressor Program Weighted Average						900	4,600

Based on the single pollutant approach, both quarterly and monthly frequencies are reasonable for methane emissions, while only quarterly is reasonable for VOC emissions. Like described for well sites, owners and operators of compressor stations have been monitoring quarterly since 2016 pursuant to NSPS OOOOa, State requirements, or voluntarily, which suggests these costs are reasonable. These costs for quarterly monitoring are also comparable to those found reasonable in both the 2016 NSPS OOOOa and the 2020 Technical Rule. Further, both frequencies are reasonable under the multipollutant approach when considering the total cost-effectiveness compared to a baseline of no OGI monitoring.

The EPA then looked at the incremental costs of going from quarterly to monthly monitoring. Quarterly monitoring achieves an emission reduction ranging from 13.3 tpy at gathering and boosting compressor stations to 114 tpy at storage compressor stations. Monthly monitoring achieves additional reductions ranging from 1.7 tpy at gathering and boosting compressor stations to 14.2 tpy at storage compressor stations. However, these additional reductions are achieved at $9,400/ton methane (and nearly $50,000/ton VOC). The EPA finds that achieving these additional emissions reductions is not reasonable for the cost, given the only small fraction of additional reductions realized at monthly monitoring. Based on the cost analysis summarized above, we find that the cost effectiveness of quarterly monitoring for compressor stations is reasonable.

Finally, no secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the OGI camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey. Using AP–42 mobile emission factors and assuming a distance of 70 miles to the compressor station, the emissions generated from quarterly monitoring at a compressor station (140 miles to and from the compressor station four times a year) is estimated to be 0.70 lb/yr of hydrocarbons, 12.0 lb/yr of CO and 0.80 lb/yr of NO_X. No other secondary impacts are expected.

In light of the above, we find that the BSER for reducing methane and VOC emissions from all compressor stations, including gathering and boosting stations, transmission stations, and storage stations is quarterly monitoring for this proposal. Therefore, for NSPS OOOOb, we are proposing to require quarterly monitoring for all compressor stations.

2. EG OOOOc

The EPA also evaluated BSER for the control of fugitive emissions at existing well sites and compressor stations. The findings were that the controls evaluated for new sources for NSPS OOOOb are appropriate for consideration under the EG OOOOc. Further, the EPA finds that the OGI monitoring, methane emission reductions, costs, and cost effectiveness results discussed above for new sources are also applicable for existing sources.

Therefore, for the EG OOOOc, the EPA is proposing presumptive standards to require quarterly monitoring for well sites with site-level baseline methane emissions greater than and equal to 3 tpy. Further, we are co-proposing semiannual monitoring for well sites with site-level baseline methane emissions greater than and equal to 3 tpy and less than 8 tpy, and quarterly monitoring for well sites with site-level baseline methane emissions greater than and equal to 8 tpy. We find the costs reasonable for existing well sites with total site-level baseline methane emissions greater than or equal to 3 tpy to conduct quarterly OGI monitoring at an incremental cost of $1,700/ton methane reduced. We are aware that there is a large percentage of existing well sites that are likely owned and operated by small businesses. We continue to be concerned about the burden of frequent OGI monitoring on these small businesses and are requesting comment consistent with our solicitation for new sources.

The EPA also finds, and is proposing, that the BSER for reducing methane emissions from all existing compressor stations, including gathering and boosting stations, transmission stations, and storage stations is quarterly monitoring. For compressor stations, we find that both quarterly (at $430/ton methane reduced) and monthly monitoring (at $900/ton methane reduced) are reasonable when looking at total cost-effectiveness against a baseline of no monitoring, however, at an incremental cost of $9,400/ton methane reduced, monthly monitoring is not reasonable. Therefore, for the EG OOOOc, we are proposing a presumptive standard of quarterly monitoring for all compressor stations.

3. Alternative Screening Using Advanced Measurement Technology

As discussed throughout this preamble, the EPA recognizes the existence large emission events. In certain instances, these situations could be caused by severely and continuously leaking components that would be identified and corrected via the routine OGI-based periodic monitoring program, but only on a quarterly or semiannual basis. Moreover, some large emission events are intermittent and stochastic in nature and may not be identified via these OGI surveys. Since the 2016 NSPS OOOOa, significant strides have occurred in developing and deploying methane detection technologies that can detect fugitive emissions (especially large emission events) in a potentially faster and more cost-effective manner than traditional techniques such as OGI and EPA Method 21. The EPA has continued following the development of these technologies and their applications through various public programs, such as the DOE ARPA–E programs, which have focused on the development of cost-effective tools to locate and measure methane emissions. Additionally, the EPA has continued discussions with stakeholders, including academic researchers and private industry, as they develop and evaluate novel tools for the detection and quantification of methane emissions in the oil and gas sector. As noted in section VII.B, the EPA also held a two-day workshop in August 2021 to hear perspectives on these new technologies. Some of the promising technologies now emerging include, but are not limited to, fixed-base and open path sensor networks, unmanned aircraft systems (UAS) equipped with methane detection equipment, the use of high-end instruments for mobile measurements on the ground and in the air, and satellite observations with advanced optical techniques.

As the EPA learned during the Methane Detection Technology Workshop, industry has utilized these advanced measurement technologies to supplement existing fugitive emissions programs and to quickly identify unexpected emissions events (*e.g.,* emissions from controlled storage vessels) in order to make repairs as quickly as possible.[246] While most of these advanced measurement technologies are not sensitive enough to pin-point the exact same emission sources as the current fugitive emission detection programs, many can more quickly detect the largest emissions sources (*e.g.,* malfunctions and undersized or non-performing major equipment), and they can also find emissions that may be missed by fugitive emission surveys (*e.g.,* component-level leaks on valves, connectors, and meters). Moreover, the EPA understands the stochastic nature, distribution, and frequency of these large emission events across sites and over time is uncertain, and that these events occur sporadically at an individual site in ways that may take longer to detect or might not be detected through a periodic fugitive emissions survey using traditional technologies. Integrating advanced emission detection technologies into this rule—whether deployed by owner-operators themselves or by third parties—could be a valuable way to reduce fugitive emissions more cost-effectively and rapidly detect and remedy ''super-emitting'' events that make an outsize contribution to overall emissions from this source category.

There are many other advantages to these advanced measurement technologies over technologies currently used for fugitive emissions detection (*i.e.,* OGI and EPA Method 21 technologies). For instance, these advanced measurement technologies may be less susceptible to operator error or judgment than traditional methods of leak detection, thus making surveys more consistent and reliable. Many of these technologies can survey broader areas than can be effectively surveyed with field personnel, drastically reducing the driving time from site to site, which could have potential cost and safety benefits and allow for more frequent monitoring, which could allow for the identification and mitigation of large volume methane emissions sooner than OGI or EPA Method 21 surveys.

As described in section XI.A.5, the EPA is proposing an alternative work practice for detecting fugitive emissions that incorporates these advanced measurement technologies. There were a number of presentations during the Methane Detection Technology Workshop that discussed the detection capabilities of various methane measurement technologies which could be used for a screening approach. Given the diverse array of advanced technologies that are now in use, and the rapid pace at which these technologies are being refined and new technologies are being developed, the EPA believes that it is appropriate to articulate a foundational set of performance criteria and documentation requirements for this alternative work practice that can be applied to multiple existing and forthcoming technologies. Based on the information available to the Agency, including the information presented in the Methane Detection Technology Workshop, the EPA believes setting a minimum detection threshold of 10 kg/hr methane might be appropriate for use in determining what technologies and in what deployment platforms (*e.g.,* fixed, ground and aerial) are appropriate for a potential screening alternative within the proposed NSPS OOOOb and EG OOOOc. Therefore, the specific alternative work practice that the EPA is proposing includes a provision that would allow the use of any technology with a minimum detection threshold of 10 kg/hr.

Although we have focused this discussion on advanced measurement technologies, the EPA is also soliciting comment on whether there are ways to utilize existing technologies to screen for large emission events. For example, could gauges or meters be utilized to identify potential large losses between the wellhead and the custody meter assembly.

Further, the EPA is seeking comment on very simple AVO checks that could be performed in conjunction with the periodic OGI monitoring surveys to help identify potential large emission events. For example, two often-cited causes of super-emitter sources are unlit flares and separator dump valves that are stuck open allowing unintentional gas carry-through to emit from storage vessels. The additional time and cost required to perform visual inspections to see if the flare pilot light is working, or to see if a dump valve is stuck open, would be minimal. Yet the benefits of simple AVO inspections could be significant. The EPA is soliciting comment on this concept, as well as comments on the common items that could be included on a checklist for such low-burden AVO inspections in conjunction with fugitive monitoring.

B. Proposed Standards for Storage Vessels

1. NSPS OOOOb

a. Background

In the 2012 NSPS OOOO, the EPA established VOC standards for storage vessels. Based on our review of these standards, we are proposing to retain the current standard of 95 percent reduction. However, the EPA is proposing to redefine the affected facility to include a tank battery. Specifically, the EPA is proposing to define a storage vessel affected facility as a single storage vessel or a group of storage vessels that are physically adjacent and that receive fluids from the

[246] See summary report of the EPA's Methane Detection Workshop located at Docket ID No. EPA–HQ–OAR–2021–0317.

same source (*e.g.,* well, process unit, or set of wells or process units) or manifolded together for the transfer of liquid or vapors. In this definition, we consider tanks to be physically adjacent when they are near or next to each other and may or may not be connected or piped together. In addition, the EPA is proposing methane standards for new, reconstructed, and modified storage vessels under the proposed NSPS OOOOb. Both the proposed revised VOC standards and the proposed methane standards would be the same (*i.e.,* 95 percent reduction of emissions from storage vessel affected facilities as defined above in this proposal). These reductions can be achieved by utilizing a cover and closed vent system to capture and route the emissions to a control device that achieves an emission reduction of 95 percent, or by routing the captured emissions to a process.

Both methane and VOC emissions from storage vessels are a result of working, breathing and flashing losses. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. Breathing losses are the release of gas associated with daily temperature fluctuations when the liquid level remains unchanged. Flashing losses occur when a liquid with dissolved gases is transferred from a vessel with higher pressure (*e.g.,* separator) to a vessel with lower pressure (*e.g.,* storage vessel), thus allowing dissolved gases and a portion of the liquid to vaporize or flash. In the Crude Oil and Natural Gas source category, flashing losses occur when crude oils or condensates flow into a storage vessel from a separator operated at a higher pressure. Typically, the higher the operating pressure of the upstream separator, the greater the flash emissions from the storage vessel. Temperature of the liquid may also influence the amount of flash emissions. Lighter crude oils and condensate generally flash more hydrocarbons than heavier crude oils.

b. Definition of Affected Facility

The current standards apply to single storage vessels with potential VOC emissions of 6 tpy or greater, although the EPA has long observed that these storage vessels are typically located as part of a tank battery. 76 FR 52738, 52763 (Aug. 23, 2011). Further, the 6 tpy applicability threshold was established by directly correlating VOC emissions to throughput, was based on the use of a single combustion control device, regardless of the number of storage vessels routing emissions to that control device, and control of 6 tpy VOC was cost effective using that single control device. *Id.* at 52763–64. Over the years, there have been questions and issues raised regarding how to calculate the potential VOC emissions from individual storage vessels that are part of a tank battery. The EPA attempted to address this issue through various amendments to NSPS OOOO and NSPS OOOOa,[247] most recently in the 2020 Technical Rule. In the 2020 Technical Rule, the EPA continued to recognize that tank batteries are more prevalent than individual storage vessels. While the 2020 Technical Rule included amendments to the calculation methodology for determining potential VOC emissions from storage vessels that are part of a tank battery, the EPA has now determined that it is more appropriate to evaluate the control of methane and VOC emissions from tank batteries [248] as a whole instead of each individual storage vessel within a tank battery.[249] In this review the EPA evaluated regulatory options based on the use of a single control device to reduce both methane and VOC emissions from a tank battery, which is consistent with the 2012 NSPS OOOO, 2016 NSPS OOOOa, and subsequent amendments to each of those rules. The EPA believes that this approach will simplify applicability criteria for owners and operators of storage vessels, and more accurately aligns with the EPA's original intent of how storage vessel affected facility status should be determined.

c. Modification

Section 60.14(a) of the general provisions to part 60 defines modification as follows: ''Except as provided in paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification. . . .'' We also note that 40 CFR 60.14(f) states that ''Applicable provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.'' The EPA understands the difficulty assessing emissions from storage vessels and seeks to provide clarity on actions that are considered modification of a tank battery by explicitly listing these in the proposed NSPS OOOOb. We evaluated circumstances that would lead to an increase in the VOC and methane emissions from a tank battery and therefore constitute a modification of an existing tank battery. A modification of an existing tank battery would then require the tank battery owner or operator to assess the potential emissions relative to the proposed NSPS instead of the EG.

The EPA is proposing that a single storage vessel or tank battery is modified when any of the following physical or operational changes are made: (1) The addition of a storage vessel to an existing tank battery; (2) replacement of a storage vessel such that the cumulative storage capacity of the existing tank battery increases; and/or (3) an existing single storage vessel or tank battery that receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery). For both items 1 and 2, even if the type and quantity of fluid processed remains the same, the increased storage capacity will lead to higher breathing losses and thereby increase the VOC emissions from the tank battery relative to the VOC emissions prior to the vessel addition or replacement. Therefore, we conclude that these actions are a modification of the tank battery. However, we are soliciting comment to help us better understand the effect of the proposed definition number 1 and 2 on the number of new storage vessels or tank batteries that would be subject to the NSPS. Under the current definition of a storage vessel affected facility in NSPS OOOOa, which is each single storage vessel that meets the 6 tpy applicability threshold, a new storage vessel that is installed in an existing tank battery is an affected facility (assuming the 6 tpy applicability threshold is met for the single storage vessel) whether the new storage vessel is a replacement or an addition to the tank battery. However, under the proposed definition number 1 and 2 above, the NSPS OOOOb is triggered only if the new storage vessel is an addition to the tank battery or is of bigger capacity than the storage vessel it is replacing in a tank battery. We therefore solicit comment on how often a storage vessel in a tank battery is replaced with one that is of bigger capacity, or whether the need to increase a tank battery's capacity is

[247] See 79 FR 79018 and 80 FR 48262.

[248] For purposes of this analysis and the resulting proposed standards, the term ''tank battery'' refers to a single storage vessel or a group of storage vessels that are physically adjacent and that receive fluids from the same source (*e.g.,* well, process unit, or set of wells or process units) or which are manifolded together for liquid or vapor transfer.

[249] This approach would no longer allow facilities to apply certain criteria and average the total potential VOC emissions of the tank battery across the number of storage vessels in the battery to determine a per-vessel potential for VOC emissions.

generally accomplished by adding storage vessels as opposed to replacing an existing one with a bigger one. We further solicit comment on whether, under our proposed definition of a tank battery (*i.e.,* a single storage vessel or a group of storage vessels that are physically adjacent and that receive fluids from the same source (*e.g.,* well, process unit, or set of wells or process units)), the replacement of a storage vessel in a tank battery should also require the assessment of the potential VOC and methane emissions from the tank battery.

Item 3 will increase the volumetric throughput of the tank battery relative to the throughput prior to storage of the additional fluid. This will increase the working losses and potentially increase the flashing losses from the tank battery, depending on the properties of the new fluid stream. In any event, adding a new fluid stream to an existing tank battery increases the VOC emissions from that tank battery relative to just prior to the addition of a new fluid stream and is therefore considered a modification of the tank battery.

The EPA is proposing to require that the owner or operator recalculate the potential VOC emissions when any of these actions occur on an existing single storage vessel or tank battery to determine if the modification may require control of VOC emissions. The existing single storage vessel or tank battery will only become subject to the proposed NSPS if it is modified pursuant to this proposed definition of modification and its potential VOC emissions exceed the proposed 6 tpy VOC emissions threshold for the tank battery.

d. Technology Review

The available control techniques for reducing methane and VOC emissions from storage vessels include routing the emissions from the storage vessels to a combustion control device or a VRU, which would route the emission to a process (including a gas sales line). These are the same control systems that were evaluated under the 2012 NSPS OOOO. While floating roofs can also be used to reduce emissions from many storage vessel applications, including at natural gas processing plants and compressor stations, floating roofs are not effective at reducing emissions from storage vessels that have flashing losses (*e.g.,* storage vessels at well sites or centralized production facilities). Besides the control options described above, we did not find other available control options through our review, including review of the RACT/BACT/LAER Clearinghouse.

In the development of the 2012 NSPS OOOO, we found that using either a VRU or a combustion control device could achieve a 95 percent or higher VOC emission reduction efficiency. Available information since then continues to support that such devices can achieve a 95 percent control efficiency for both methane and VOC emissions. We are not proposing to require higher control efficiency because, in order to achieve a minimum of 95 percent control efficiencies on a continuous basis, operators will need to design and operate the control to achieve greater than 95 percent. Thus, while the control device may commonly operate at greater than 95 percent control efficiencies, there may be process fluctuations in heat loads, inlet backpressure, and other variables that may affect performance that may lower the control efficiencies achieved. For example, there are field conditions, such as high winds that may influence combustion efficiencies.[250] We also note that, while the EPA established operating and monitoring requirements to ensure flares achieve a 98 percent control efficiency at petroleum refineries in 40 CFR part 63, subpart CC, these requirements include sophisticated monitoring and operational controls and tend to lead to additional fuel use and greater secondary impacts than combustion systems targeting to achieve a minimum of 95 percent control efficiency. Considering these factors, we conclude that, consistent with CAA section 111(a) definition of a ''standard of performance,'' 95 percent control efficiency as the minimum allowable control efficiency at any time continues to reflect ''the degree of emission limitation achievable'' through the application of the BSER for tank batteries (a combustor or a VRU). We solicit comment on the issues described above for requiring higher than 95 percent reduction.[251]

During pre-proposal outreach, some small businesses raised a concern that the NSPS OOOOa requirement for a continuous pilot light for a storage vessel control device generated more emissions than it prevented for storage vessels with low emissions. Specifically, small business representatives raised concerns that there are situations where propane or other fossil fuel must be used to maintain continuous pilot lights for flares used as control devices on storage vessels that do not produce enough emissions. The EPA is interested in whether the benefits of reducing emissions with these control devices are negated by the need to burn additional fossil fuels and whether there are additional factors that lead to variability in emissions from storage vessels that could be used to more narrowly target these requirements to limit the unnecessary operation of flares. We are soliciting comment from all stakeholders on this issue.

e. Control Options and BSER Analysis

For this proposal, the EPA evaluated regulatory options based on different potential emissions thresholds for VOC and methane. We assumed the potential tank battery emissions were reduced by 95 percent using either a VRU or a combustion control device. Since VRUs recover saleable products, we also estimated the value of the recovered product when VRUs were used. The EPA encourages the use of VRUs to capture and sell the emissions from the storage vessels by classifying VRUs as part of the process, therefore emission recovered would not be included in the potential emissions at a site.

For new, modified, or reconstructed sources, we evaluated the cost of control using a single combustion device (or VRU) on a single storage vessel as well as a tank battery made up of multiple storage vessels. To do this, we evaluated the use of a single control device achieving 95 percent reduction of VOC and methane emissions at the following potential emission thresholds: 6 tpy VOC from a single storage vessel; 3 and 6 tpy VOC from a tank battery; and 1.3 tpy, 5.3 tpy, 20 tpy, and 50 tpy methane from a tank battery. Based on our cost analysis we propose to retain the 6 tpy applicability threshold.

The estimated all-in capital costs for a single combustion control device are approximately $80,000. The estimated annualized costs include the capital recovery cost (calculated at a 7 percent interest rate for 15 years) and labor costs for operations and maintenance and are estimated at approximately $31,500/yr. The estimated capital costs for a VRU sized for a source with potential VOC emissions of 6 tpy are approximately $32,000 and the estimated annualized costs are estimated at approximately $24,000/yr not considering any potential recovery credits from sales. More information on this cost analysis

[250] EPA. April 2012. *Parameters for Properly Designed and Operated Flares.* Prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC.

[251] Further, in section XIII.E (solicitation of comment on control device efficiency), the EPA solicits comment on the level of reduction that can be reliably achieved using a flare and what measures need to be in place to assure such reduction.

is available in the NSPS OOOOb and EG TSD for this proposal.

Based on our analysis, the cost effectiveness of controlling VOC and methane emissions from a tank battery with the potential for VOC emissions of 6 tpy, under the single pollutant approach where all the costs are assigned to the reduction of VOC, is $5,540 per ton of VOC eliminated assuming the use a single combustion control device. As explained above, storage vessels are commonly located adjacent to one another as part of tank battery, which allows the vapors from the storage vessels within the tank battery to be collected and routed to a single control device, when one is used. The single pollutant cost effectiveness for a VRU to control a tank battery with potential VOC emissions of 6 tpy is approximately $4,000 per ton of VOC eliminated. As shown in section IX, costs ranging from $4,000 to $5,540 per ton of VOC reduced are within the range that the EPA considers to be cost effective for reducing VOC emissions. Because it is cost effective to reduce the VOC emissions from a tank battery with potential VOC emissions of 6 tpy or greater, one of the two targeted pollutants in this action, it is cost effective to reduce both VOC and methane emissions from a single storage vessel or a tank battery at that level. Based on our estimate, a tank battery with potential 6 tpy VOC emissions has potential 1.3 tpy of methane emissions. Because storage vessels contain crude oil, condensate, intermediate hydrocarbons, or produced water, which are approximately 80 percent VOC, the methane emissions from storage vessels are generally less than the VOC emissions.

We also evaluated the cost effectiveness at a lower VOC threshold of 3 tpy. As shown in the NSPS OOOOb and EG TSD, the single pollutant cost effectiveness for controlling a tank battery with potential emissions of 3 tpy ranges from $7,500 to $11,000. As shown in section IX, costs ranging from $7,500 to $11,000 per ton of VOC reduced is not within the range that the EPA considers to be cost effective for reducing VOC emissions. Using the multipollutant approach, the VOC cost effectiveness is between $3,800 and $5,500, which is considered reasonable, but the methane cost effectiveness is between $17,000 and $25,000 for any of the methane thresholds assessed in conjunction with 3 tpy VOC limit, which is considered unreasonable. Therefore, the 3 tpy VOC control option was not considered reasonable at this time using either the single pollutant or multipollutant approach.

Our analysis also shows that, under the single pollutant approach where all the costs are assigned to the reduction of methane and zero to VOC, it is cost effective to control a single storage vessel or a tank battery with potential methane emissions of 20 tpy (at costs ranging from $1,250 to $1,660 per ton methane). Based on our estimate, a tank battery with potential methane emissions of 20 tpy would have the potential VOC emissions of 91 tpy, 95 percent of which would be reduced at zero cost. Under the multipollutant cost-effectiveness approach, where half of the cost is allocated to methane reduction and the other half to VOC reduction, it is cost effective to control a tank battery with potential methane emissions of 10 tpy and corresponding potential VOC emissions of 46 tpy, at an average cost of $1,500 per ton methane reduced and $330 per ton VOC reduced. In light of the above, 6 tpy of VOC is the lowest threshold that is cost effective to control both VOC and methane emissions. Therefore, the EPA is proposing to define the affected facility for purposes of regulating both VOC and methane emissions as a tank battery with potential VOC emissions of 6 tpy or greater.

2. EG OOOOc

The EPA is proposing presumptive standards for reducing methane emissions from existing storage vessels. For purposes of the EG, we are proposing to define a designated facility as a single storage vessel or tank battery with the potential for methane emissions of 20 tpy or greater. For purposes of the EG, we are proposing the same definition of a storage vessel affected facility, which is a single storage vessel or a group of storage vessels that are physically adjacent and that receive fluids from the same source (*e.g.,* well, process unit, or set of wells or process units).

The available controls for reducing methane emissions from existing tank batteries are the same as those for reducing methane and VOC emissions from new, modified and reconstructed tank batteries. In assessing the control costs for existing sources, we applied a 30 percent retrofit factor to the capital and installation costs to account for added costs of manifolding existing storage vessels and installing the control system on an existing tank battery. When applying controls to new sources, there is limited additional costs in designing the fixed roof with fittings to manifold the vapors and installing the closed vent piping or ducts during the tank installation process. For existing sources, installing fittings on an existing tank may require special lifts to access the roof and cut new ports in the roof. This may also require the tank to be taken out of service to conduct these installations, which requires additional time and labor. Additionally, when installing controls as part of the design for a new source, the facility layout can be designed to accommodate the control systems near the tank battery and the control device can be installed with the same crew installing the storage vessels, minimizing additional installation costs. For existing sources, there may be other equipment near the tanks that may require the control equipment to be further from the tank battery, which increases materials and installation costs. Also, control equipment costs will include the full costs of crew mobilization. Therefore, it is more expensive to install controls at an existing tank battery than to install controls as part of a new tank battery. We considered the same regulatory options based on potential methane emissions thresholds of 1.3 tpy, 5.3 tpy, 20 tpy, and 50 tpy per tank battery.

The estimated capital costs for a single combustion control device for emissions in this range are approximately $103,000. The estimated annual costs include the capital recovery cost (calculated at a 7 percent interest rate for 15 years) and labor costs for operations and maintenance and are estimated at approximately $34,000. The costs for VRU are more variable than combustion control systems and dependent on the potential emissions for which the VRU is designed to recover. The estimated capital costs for a VRU sized for a source with potential methane emissions of 20 tpy device are approximately $106,000 and the estimated annualized costs are approximately $49,000/yr not considering any potential recovery credits. With a VRU, the recovered VOC and methane are recovered as salable products. Considering the value of recovered product, the annualized cost for VRU sized to recover potential methane emissions of 20 tpy is estimated to be $26,000/yr. More information on this cost analysis is available in the NSPS OOOOb and EG TSD for this proposal.

The resulting cost effectiveness, for the application of a single combustion control device or VRU to achieve a 95 percent emission reduction ranges from $19,000 to $27,400 per ton of methane eliminated at a threshold of 1.3 tpy methane. This cost is not considered reasonable. Next, we evaluated the cost effectiveness at a methane threshold of 5.3 tpy, which ranged from $10,000 to $13,700 per ton of methane reduced,

which is also not considered reasonable. At a threshold of 20 tpy methane, the cost effectiveness ranges from $1,400 to $1,800 per ton methane reduced. At a threshold of 50 tpy methane, the cost effectiveness ranges from $340 to $720 per ton methane reduced. When we considered the application of these options at a national level, the overall cost effectiveness of the 20 tpy potential methane emissions threshold was $400 per ton methane reduced without considering product recovery credits and has a net cost savings considering product recovery credits. Additionally, the incremental cost effectiveness of the 20 tpy option relative to the 50 tpy potential methane emissions threshold was approximately $900 per ton additional methane reduced when considering product recovery credits.

Based on the cost analysis summarized above, we find that the cost effectiveness for achieving 95 percent emission reduction of methane from a tank battery with potential methane emissions of 20 tpy is reasonable for methane. A cost-effective value of $1,800/ton of methane reduction is comparable to the estimated methane cost-effectiveness values for the controls identified as BSER for the 2016 NSPS OOOOa and which we consider to be representative of reasonable control cost for reducing methane emissions from the Crude Oil and Natural Gas source category, as explained in section IX.B. We further note that both California and Colorado require 95 percent reduction of methane (California) and hydrocarbon (Colorado) emissions from storage vessels. For California, existing separator and tank systems with an annual emission rate greater than 10 tpy methane must control emissions using a vapor collection system that reduces emissions by at least 95 percent.[252] For Colorado, storage vessels that emit greater than or equal to 2 tpy of actual uncontrolled VOC emissions must reduce VOC emissions by 95 percent.[253] These requirements, which are comparable to the proposed presumptive standards, are further indication that the cost of implementing the proposal is reasonable and not excessive.

3. Legally and Practicably Enforceable Limits

In addition to the BSER analysis described above, the EPA is clarifying the term ''legally and practicably enforceable limits'' as it related to storage vessel affected facilities in the proposed NSPS OOOOb and EG OOOOc. In the 2016 NSPS OOOOa, the EPA stated that ''any owner or operator claiming technical infeasibility, nonapplicability, or exemption from the regulation has the burden to demonstrate the claim is reasonable based on the relevant information. In any subsequent review of a technical infeasibility or nonapplicability determination, or a claimed exemption, the EPA will independently assess the basis for the claim to ensure flaring is limited and emissions are minimized, in compliance with the rule.'' See 81 FR 35824, 35844 (June 3, 2016).

In the context of storage vessels under both the 2012 NSPS OOOO and 2016 NSPS OOOOa, the EPA has learned that numerous owners and operators claim that their storage vessels are not affected facilities under 40 CFR 60.5365(e) and 40 CFR 60.5365a(e). This claim is made based on a determination that the potential for VOC emissions is less than 6 tpy when taking into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, State, local or Tribal authority.[254] However, when the EPA has reviewed the limits considered by these facilities as legally and practicably enforceable, we have become aware that the limits do not require a reduction in emissions; they are often self-imposed or of such a general nature as to be unenforceable or otherwise lack measures to assure the required emission reduction. For example, a permit contains an emission limit of 2 tpy for a single storage vessel, but does not contain any performance testing requirements, continuous or other monitoring requirements, recordkeeping and reporting, or other requirements that would ensure that emissions are maintained below the emissions limit in the permit. In *National Mining Ass'n* v. *EPA,* 59 F.3d 1351 (D.C. Cir. 1995), the court explained what constitutes ''effective'' control in assessing a source's potential to emit. According to the court, while ''effective'' controls need not be Federally enforceable, ''EPA is clearly not obliged to take into account controls that are only chimeras and do not really restrain an operator from emitting pollution.'' *Id.* at 1362. The court also emphasized that these non-Federally enforceable controls must stem from state or local government regulations, and not ''operational restrictions that an owner might voluntarily adopt.'' *Id.* at 1362. Further, as a general ''default rule,'' the burden of proof falls ''upon the party seeking relief.'' *Schaffer ex rel. Schaffer* v. *Weast,* 546 U.S. 49, 57–58, 126 S.Ct. 528, 163 L.Ed.2d 387 (2005).

In light of the above, the EPA is proposing to include a definition for a ''legally and practicably enforceable limit'' as it relates to limits used by owners and operators to determine the potential for VOC emissions from storage vessels that would otherwise be affected facilities under these rules. The intent of this proposed definition is to provide clarity to owners and operators claiming the storage vessel is not an affected facility in the Oil and Gas NSPS due to legally and practicably enforceable limits that limit their potential VOC emissions below 6 tpy. This definition is being proposed for NSPS OOOOb and the proposed presumptive standard included in EG OOOOc. This proposed definition of ''legally and practicably enforceable limit'' is consistent with the EPA's historic position on what is considered ''legally and practicably enforceable,'' as tailored to storage vessels in the oil and gas sector that would otherwise be affected facilities under these rules. The proposed definition is as follows:

''For purposes of determining whether a single storage vessel or tank battery is an affected facility, a legally and practicably enforceable limit must include all of the following elements:

i. A quantitative production limit and quantitative operational limit(s) for the equipment, or quantitative operational limits for the equipment;

ii. an averaging time period for the production limit in (i) (if a production-based limit is used) that is equal to or less than 30 days;

iii. established parametric limits for the production and/or operational limit(s) in (i), and where a control device is used to achieve an operational limit, an initial compliance demonstration (*i.e.,* performance test) for the control device that establishes the parametric limits;

iv. ongoing monitoring of the parametric limits in (iii) that demonstrates continuous compliance with the production and/or operational limit(s) in (i);

v. recordkeeping by the owner or operator that demonstrates continuous

[252] See sections 95668 and 95671 of California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4.

[253] See section I.D.3.a of Colorado Department of Public Health and Environment, ''Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides), Regulation Number 7'' (5 CCR 1001–9), July 2021.

[254] 40 CFR 60.5365(e) and 40 CFR 60.5365a(e)(1) and (2) allow owners and operators to take into account these requirements when calculating the potential VOC emissions.

compliance with the limit(s) in (i–iv); and

vi. periodic reporting that demonstrates continuous compliance.''

In this proposed definition, the EPA is not addressing the various ways in which a State or other authority's permit may be issued since the format of permit issuances varies by jurisdiction. The proposed definition of ''legally and practicably enforceable'' does not specify limits, monitoring requirements, or recordkeeping. Instead, the owner or operator should work with the permitting authority to establish specific limits, monitoring requirements and recordkeeping that will ensure any permitted emission limit is achieved. Only those limits that include the elements described above will be considered ''legally and practicably enforceable'' for purposes of determining the potential for VOC emissions from a single storage vessel or tank battery, and thus applicability (or non-applicability) of each single storage vessel or tank battery as an affected facility under the rule.

This proposed definition will provide clarity to owners and operators in what limits are necessary to ensure they have appropriately determined their single storage vessels or tank batteries are affected facilities under the proposed NSPS OOOOb or designated facilities under the proposed EG OOOOc. Further, as stated in the 2016 NSPS OOOOa, well-designed rules ensure fairness among industry competitors and are essential to the success of future enforcement efforts. 81 FR 35844 (June 3, 2016). The EPA is soliciting comment on this proposed definition from all stakeholders.

C. Proposed Standards for Pneumatic Controllers

1. NSPS OOOOb

a. Background

In the 2012 NSPS OOOO, the EPA established VOC standards for natural gas-driven pneumatic controllers. Specifically, subpart OOOO established a natural gas bleed rate limit of 6 scfh for individual, continuous bleed, natural gas-driven controllers located in the production segment. Continuous bleed, natural gas-driven controllers with a bleed rate of 6 scfh or less are commonly called ''low bleed'' controllers. However, that rule also allowed for the use of ''high bleed'' controllers (those with a bleed rate over 6 scfh) where required by functional needs such as response time, safety, and positive actuation. At natural gas processing plants, subpart OOOO implemented a VOC standard that required a bleed rate of zero (''zero bleed'' or ''no bleed''). The rule also included allowances for the use of continuous bleed natural gas-driven controllers at natural gas processing plants where required by functional needs.

In the 2016 NSPS OOOOa, the EPA extended the 6 scfh natural gas bleed rate standard to the natural gas transmission and storage segment and established GHG standards for all segments. Effectively, the 2016 NSPS OOOOa required low bleed controllers to reduce methane and VOC emissions from the production and transmission and storage segments and required a bleed rate of zero for pneumatic controllers at natural gas processing plants. Like the 2012 NSPS OOOO, the 2016 NSPS OOOOa included allowances for the use of continuous high bleed controllers in the production and transmission and storage segments and continuous natural gas-driven pneumatic controllers at natural gas processing plants where required by functional needs.

Emissions from natural gas-driven intermittent vent pneumatic controllers were not addressed in either the 2012 NSPS OOOO or the 2016 NSPS OOOOa. This was because, when operated and maintained properly, methane and VOC emissions from intermittent controllers are substantially lower (by an order of magnitude) than emissions from other types of natural gas-driven controllers. However, the EPA is now aware that these intermittent controllers often malfunction and vent during idle periods. Emissions factors considering this fact are around four times higher than the factors for low-bleed controllers. Further, as presented in subsection c of this section, methane emissions from intermittent controllers make up a significant portion of the overall methane emissions from all natural gas and petroleum system sources in the GHGI. As such, the EPA is now proposing to reduce emissions from intermittent controllers via NSPS OOOOb.

b. Affected Facility Definitions and Zero Emissions Standard

As a result of the review of these requirements in the 2016 NSPS OOOOa, the previous BSER determinations, and the consideration of new information, including State regulations that have been enacted since 2016, the EPA is proposing GHG (methane) and VOC standards for natural gas-driven pneumatic controllers in all segments of the industry included in the Crude Oil and Natural Gas source category (*i.e.,* production, processing, transmission and storage).

First, in terms of the definition of an affected facility, the EPA is proposing to revise the types of pneumatic controllers that are affected facilities to include both continuous bleed controllers and intermittent vent controllers. For continuous bleed controllers, an affected facility is each single continuous bleed natural gas-driven pneumatic controller that vents to the atmosphere. For intermittent vent controllers, an affected facility is each single natural gas-driven pneumatic controller that is not designed to have a continuous bleed rate but is designed to only release natural gas to the atmosphere as part of the actuation cycle. These affected facility definitions apply for pneumatic controllers in both the production and transmission and storage segments, as well as for those at natural gas processing plants.

Next, in terms of standards, we are proposing a requirement that all controllers (continuous bleed and intermittent vent) in the production and natural gas transmission and storage segments must have a methane and VOC emission rate of zero. Controllers that emit zero methane and VOC to the atmosphere can include, but are not limited to, air-driven pneumatic controllers (also referred to as instrument air-driven or compressed air-driven controllers), mechanical controllers, electronic controllers, and self-contained natural gas-driven pneumatic controllers. While these ''zero-emissions controllers'' would not technically be affected facilities because they are not driven by natural gas (air-driven, mechanical, and electronic) or because they do not vent to the atmosphere, owners and operators should maintain documentation if they would like to be able to demonstrate to permit writers or enforcement officials that there are no methane or VOC emissions from the controllers and that these controllers are not affected facilities and are not subject to the rule. The proposed standard would apply to both continuous bleed and intermittent vent controllers at these sites.

For all natural gas processing plants, we are proposing to essentially retain the 2016 NSPS OOOOa standard that requires that controllers must have a methane and VOC emission rate of zero (*i.e.,* zero-emissions controllers must be used). However, we are proposing to slightly change the wording of the standard from subparts OOOO and OOOOa, which require a ''bleed rate of zero.'' Many natural gas processing plants use pneumatic controllers that are powered by compressed air, which

can technically have a compressed air bleed rate greater than zero. Put another way, some controllers that are powered with compressed air can allow some of that compressed air to leave the controller and thus be released into the atmosphere (they can ''bleed'' compressed air). However, since the compressed air does not contain any natural gas, methane, or VOC, we are clarifying the standard by proposing to require that pneumatic controllers at natural gas processing plants have a methane and VOC emission rate of zero.

In both NSPS OOOO and OOOOa, there is an exemption from the standards in cases where 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. The EPA is not maintaining this exemption in the proposed NSPS OOOOb, except for in very limited circumstances explained below. As discussed below, the reasons to allow for an exemption based on functional need in NSPS OOOO and OOOOa were based on the inability of a low-bleed controller to meet the functional requirements of an owner/operator such that a high-bleed controller would be required in certain instances. Since we are now proposing that pneumatic controllers have a methane and VOC emission rate of zero, we do not believe that the reasons related to the use of low bleed controllers are still applicable.

The proposed rule also does include an exemption from the zero-emission requirement for pneumatic controllers in Alaska at locations where electricity power is not available. In these situations, the proposed standards would require the use of a low-bleed controller instead of high-bleed controller. The proposed rule also includes the exemption for pneumatic controllers in Alaska at sites without power that would allow the use of high-bleed controllers instead of low-bleed based on functional needs. In addition, inspections of intermittent vent controllers to ensure they are not venting during idle periods described above would also be required at sites in Alaska without power.

c. Description

Pneumatic controllers are devices used to regulate a variety of physical parameters, or process variables, using air or gas pressure to control the operation of mechanical devices, such as valves. The valves, in turn, control process conditions such as levels, temperatures and pressures. When a pneumatic controller identifies the need to alter a process condition, it will open or close a control valve. In many situations across all segments of the Oil and Natural Gas Industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control the valve. In these ''natural gas-driven'' pneumatic controllers, natural gas may be released with every valve movement (intermittent) and/or continuously from the valve control. Pneumatic controllers can be categorized based on the emissions pattern of the controller. Some controllers are designed to have the supply-gas provide the required pressure to power the end-device, and the excess amount of gas is emitted. The emissions of this excess gas are referred to as ''bleed,'' and this bleed occurs continuously. Controllers that operate in this manner are referred to as ''continuous bleed'' pneumatic controllers. These controllers can be further categorized based on the rate of bleed they are designed to have. Those that have a bleed rate of less than or equal to 6 scfh are referred to as ''low bleed,'' and those with a bleed rate of greater than 6 scfh are referred to as ''high bleed.'' Another type of controller is designed to release gas only when the process parameter needs to be adjusted by opening or closing the valve, and there is no vent or bleed of gas to the atmosphere when the valve is stationary. These types of controllers are referred to as ''intermittent vent'' pneumatic controllers. A third type of natural gas-driven controller releases gas to a downstream pipeline instead of the atmosphere. These ''self-contained'' types of controllers can be used in applications with very low pressure.

As discussed above, emissions from natural gas-powered pneumatic controllers occur as a function of their design. Self-contained controllers do not emit natural gas to the atmosphere. Continuous bleed controllers using natural gas as the power source emit a portion of that gas at a constant rate. Intermittent vent controllers using natural gas as the power source are designed to emit natural gas only when the controller sends a signal to open or close the valve, which is called actuation. From continuous bleed and intermittent vent controllers, another source of emissions is from improper operation or equipment malfunctions. In some instances, a low bleed controller may emit natural gas at a higher level than it is designed to do (*i.e.,* over 6 scfh) or an intermittent vent controller could emit continuously or near continuously rather than only during actuation.

Not all pneumatic controllers are driven by natural gas. At sites with power, electrically powered pneumatic devices or pneumatic controllers using compressed air can be used. As these devices are not driven by pressurized natural gas, they do not emit any natural gas to the atmosphere, and consequently, they do not emit VOC or methane to the atmosphere. In addition, some controllers operate mechanically without a power source or operate electronically rather than pneumatically. At sites without electricity provided through the grid or on-site electricity generation, mechanical controllers and electronic controllers using solar power can be used.

The emissions from natural gas-powered pneumatic controllers represent a significant portion of the total emissions from the Oil and Natural Gas Industry. In the 2021 GHGI, the estimated methane emissions for 2019 from pneumatic controllers were 700,000 metric tons of methane for petroleum systems and 1.4 million metric tons for natural gas systems. These levels represent 45 percent of the total methane emissions estimated from all petroleum systems (*i.e.,* exploration through refining) sources and 22 percent of all methane emissions from natural gas systems (*i.e.,* exploration through distribution). The vast majority of these emissions are from natural gas-driven intermittent vent controllers, which the EPA is proposing to define as an affected facility for the first time in NSPS OOOOb. Of the combined methane emissions from pneumatic controllers in the petroleum systems and natural gas systems production segments, emissions from intermittent vent controllers make up 88 percent of the total. Continuous high bleed and low bleed controllers make up 8 and 4 percent, respectively.

d. Control Options

In identifying control options for this NSPS OOOOb proposal, we re-examined the options previously evaluated in the rulemakings to promulgate the 2012 NSPS OOOO and the 2016 NSPS OOOOa, and also examined State rules with requirements for pneumatic controllers that achieve emission reductions beyond those achieved by NSPS OOOOa. For NSPS subparts OOOO and OOOOa, we identified options for reducing emissions from continuous bleed natural gas-driven pneumatic controllers. These options included using low bleed controllers in place of

high bleed controllers, enhanced maintenance (*i.e.,* periodic inspection and repair), and using zero-emissions controllers. For the production and transmission and storage segments, only the option to require low bleed controllers was fully analyzed in these previous analyses. Based on the EPA's determination at that time that electricity was ''likely unavailable'' at production and transmission and storage sites, the EPA did not fully consider instrument air or electronic controllers. The EPA also did not evaluate enhanced maintenance, as it was concluded that the highly variable nature of determining the proper methods of maintaining a controller could incur significant costs. The EPA did not evaluate options to reduce emissions from intermittent vent controllers in either the 2012 or 2016 NSPS.

Three U.S. States (California, Colorado, and New Mexico) and two Canadian provinces (Alberta and British Columbia) have rules or proposed rules that achieve emission reductions beyond those achieved by NSPS OOOOa. Starting on January 1, 2019, and subject to certain exceptions, a California rule requires that all new and existing continuous bleed devices must not vent natural gas to the atmosphere. The rule allows low bleed devices installed prior to January 1, 2016, to continue to operate, provided that annual testing is performed to verify that the low bleed rate is maintained. A Colorado rule adopted in February 2021, requires that all new controllers are no-bleed controllers (which includes self-contained natural gas-driven controllers), and over a period of two years, a sizeable portion of existing controllers must be retrofit to have a natural gas bleed rate of zero. New Mexico has proposed a rule that would require an emission rate of zero from all controllers located at sites with access to electrical power. The Canadian provinces of Alberta (effective 2022) and British Columbia (effective 2021) also regulate emissions from pneumatic controllers. In British Columbia, pneumatic devices that emit natural gas must not be used at new sources and at existing gas processing plants and large compressor stations, and in Alberta, owners and operators must prevent or control (by 95 percent) vent gas from new pneumatic controllers. While the terminology differs across these regulations, the EPA believes that all these requirements (with the exception of the 95 percent reduction requirement in Alberta) are very similar to if not the same as the zero methane and VOC emission requirement being proposed by the EPA for NSPS OOOOb.

From EPA's review of our past BSER analysis as well as reviewing these other rules, several options were identified for the BSER analysis for NSPS OOOOb to reduce methane and/or VOC emissions from natural gas-driven pneumatic controllers. These include the following: (1) Use of low bleed natural gas-driven pneumatic controllers in the place of high bleed natural gas-driven pneumatic controllers; (2) require zero emissions from intermittent vent controllers except during actuation, and (3) prohibit the emissions of methane and VOC from all pneumatic controllers (*i.e.,* establish a zero methane and VOC emission standard for both continuous bleed and intermittent bleed controllers).

e. 2021 BSER Analysis

Production and Transmission and Storage Segments

For production and transmission and storage sites, the EPA evaluated two options. The first was an option to require the use of low bleed natural gas-driven pneumatic controllers in the place of high bleed natural gas-driven pneumatic controllers, along with a requirement that natural gas-driven intermittent vent pneumatic controllers only discharge natural gas during actuation. We also evaluated an option of establishing a zero methane and VOC emissions standard, which we propose to determine represents the BSER for production and natural gas transmission and storage sites.

The first option evaluated was the use of low bleed natural gas-driven pneumatic controllers in the place of high bleed natural gas-driven pneumatic controllers. In the analysis of this option, we examined the emissions reduction potential, the cost of implementation, and the cost effectiveness in terms of cost per ton of emissions eliminated.

The emission reduction potential of using a low bleed controller in place of a high bleed controller depends on the actual bleed rate of each device, which varies from device to device. Using average emission factors for each device type, the difference in emissions can be estimated on a per-controller basis. We estimated this difference between a low bleed and a high bleed device to be an 84 percent reduction for controllers in the production segment and a 92 percent reduction in emissions in the transmission and storage segment, equating to a difference of 2.1 tpy methane and 0.6 tpy VOC per controller in the production segment and 2.9 tpy methane and 0.08 tpy VOC per controller in the transmission and storage segment. The cost of a new low bleed natural gas-driven pneumatic controller is approximately $255 higher than the cost of a new high bleed device. On an annualized basis, assuming a 15-year equipment lifetime and a 7 percent interest rate, the cost is $28 per year per low bleed controller. Under the single pollutant approach where all the costs are assigned to the reduction of one pollutant, the estimated cost effectiveness is $13 per ton of methane avoided and $48 per ton of VOC avoided per controller in the production segment. Using the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the estimated cost effectiveness is $7 per ton of methane avoided and $24 per ton of VOC avoided. When considering the cost of saving the natural gas that would otherwise be emitted for the production segment, the cost effectiveness shows an overall savings under both the single pollutant and multipollutant approaches. For the natural gas transmission and storage segment, the cost effectiveness is $10 per ton methane avoided and $355 per ton VOC avoided per controller using the single pollutant method, and $5 per ton of methane and $178 per ton of VOC avoided per controller using the multipollutant method. Transmission and storage facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted/lost was not applied for this segment. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

We also evaluated a requirement that natural gas-driven intermittent vent pneumatic controllers only discharge natural gas during actuations. This emissions reduction option would be required in conjunction with a requirement to use low bleed controllers in place of high bleed controllers. The average emission factor determined by an industry study for natural gas-driven intermittent vent controllers, including both properly and improperly operating controllers, is 9.2 scfh natural gas.[255] Comparing this to the emission factor for a properly operating intermittent vent controller of 0.3 scfh natural gas illustrates the significant potential for reductions from a program that

[255] API Field Measurement Study: ''Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas.'' November 7, 2019—Pittsburgh PA. Paul Tupper.

identifies intermittent vent controllers that are improperly operating and repairing, replacing, or altering their operating conditions so they may function properly. To ensure these devices are emitting natural gas only during actuations in accordance with their design, there would be no equipment expenditure or associated capital costs; however, emissions monitoring or inspections, combined with repair as needed, would be necessary to ensure this proper operation is achieved. We considered requiring independent inspections specifically for intermittent vent controllers but concluded that it would be more efficient to couple inspections of these controllers with the inspections of equipment for leaks under the fugitive monitoring program (see section XII.A of this preamble).

The second option we evaluated was a zero methane and VOC emissions standard. While applicability of both the 2012 NSPS OOOO and the 2016 NSPS OOOOa are based on an individual pneumatic controller (as is the proposed definition of affected facility under NSPS OOOOb), zero-emissions controller options are more appropriately evaluated as ''site-wide'' controls. While individual natural gas-driven pneumatic controllers can be switched to other types of natural-gas driven pneumatic controllers (*e.g.,* high bleed to low bleed types or low bleed to self-contained), the implementation of some zero-emissions controllers options would require equipment that would presumably be used for all the controllers at the site. For example, in order to utilize instrument air driven controllers, a compressor and related equipment would need to be installed. For the vast majority of situations, the EPA does not believe that an owner and operator would install a compressor just for a single controller, but rather would instead install a site-wide system to provide compressed air to all the controllers at the site. Therefore, to adequately account for the costs of the system, including the controllers and the common equipment, we evaluated these zero-emissions controller options using ''model'' plants.

These model plants include assumptions regarding the number of each type of pneumatic controller at a site. Emissions were estimated for each of the model plants using a calculation based on of the number of controllers at the plant and emission factors for each controller. Three sizes of model plants (*i.e.,* small, medium, and large) were developed and used for both the production and transmission and storage segments. Each model plant contained one high bleed natural gas-driven controller and increasing numbers of low bleed and intermittent natural gas-driven controllers. For the production segment, the controller-specific emission factors used are from a recent study conducted by the American Petroleum Institute,[256] and are 2.6 scfh, 16.4 scfh, and 9.2 scfh total natural gas emissions for low bleed, high bleed, and intermittent bleed controllers, respectively. This API study did not cover the transmission and storage segment; therefore, the emission factors from GHGRP subpart W were used, which are 1.37 scfh, 18.2 scfh, and 2.35 scfh for low bleed, high bleed, and intermittent bleed controllers, respectively. It was assumed that the portion of natural gas that is methane is 82.9 percent in the production segment and 92.8 percent in the transmission and storage segment. Further, it was assumed that VOCs were present in natural gas at a certain level compared to methane. The specific ratios assumed were 0.278 pounds VOC per pound methane in the production segment and 0.0277 pounds VOC per pound methane in the transmission and storage segment. This information results in estimated emissions for a single natural gas-driven pneumatic controller in the production segment of 0.39, 2.48, and 1.39 tpy methane and 0.1, 0.7, and 0.4 tpy VOC per low bleed, high bleed, and intermittent vent controller, respectively. The emissions for a single natural gas-driven pneumatic controller in the transmission and storage segment are 0.23, 3.08, and 0.40 tpy methane and 0.006, 0.08, and 0.01 tpy VOC per low bleed, high bleed, and intermittent vent controller, respectively.

Based on the factors described above and the number of each type of controller in each model plant, baseline emissions for the model plants were calculated. For the production model plants, the baseline emissions were calculated to be 5.7 tpy methane and 1.6 tpy VOC for the small model plant (assumes fewer controllers on site than medium plant), 11.2 tpy methane and 3.1 tpy VOC for the medium model plant (assumes more controllers on site than small plant), and 24.9 tpy methane and 6.9 tpy VOC for the large model plant (assumes more controllers on site than the medium plant). For the transmission and storage model plants, the baseline emissions were calculated to be 4.1 tpy methane and 0.1 tpy VOC for the small model plant, 5.7 tpy methane and 0.2 tpy VOC for the medium model plant, and 10.0 tpy methane and 0.3 tpy VOC for the large model plant. For detailed information on the configuration of these model plants and the calculation of the baseline emissions, see the NSPS OOOOb and EG TSD for this rulemaking, which is available in the docket.

Instrument air controllers and electronic controllers were the two zero emission options evaluated. Both these options require electricity to operate. Instrument air systems use compressed air as the signaling medium for pneumatic controllers and pneumatic actuators, whereas electronic controllers send an electric signal to an electric actuator (rather than sending a pneumatic signal to a pneumatic actuator). As instrument air systems are usually installed at facilities where there is a high concentration of pneumatic control valves, electrical power from the grid, and the presence of an operator that can ensure the system is properly functioning, we evaluated the use of instrument air for the large model plant with more controllers and the use of electronic controllers, which can be powered by solar panels, at the small and medium-sized model plant with less controllers. The emission reduction potential of using these zero-emissions controllers rather than natural-gas-driven pneumatic controllers is 100 percent since these systems eliminate all natural gas emissions (they do not emit any VOC or methane). Based on the information available to the EPA during development of this proposal, these two zero-emissions options were the only two analyzed. The EPA solicits comment on the other potential zero-emission options for these sites (mechanical-only controllers, self-contained natural gas-driven controllers, and natural gas-driven controllers where the emissions are captured and routed to a process).

For the small and medium-sized model plants, the zero-emissions option evaluated was the use of electronic controllers. The respective emissions reduction for small and medium-sized plants would be 5.7 and 11.2 tpy methane and 1.6 and 3.1 tpy VOC in the production segment and 4.1 and 5.7 tpy methane and 0.11 and 0.16 tpy VOC in the transmission and storage segment. The cost of a new electronic controller system using electricity from the grid or other on-site power generation is estimated to be $26,000 and $46,000, for small and medium-sized plants respectively. The cost of a new solar-powered electronic controller system is

[256] API Field Measurement Study: ''*Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas.*'' November 7, 2019—Pittsburgh PA. Paul Tupper.

estimated to be $28,000 and $52,000, for small and medium-sized plants respectively. The estimated annualized capital costs, assuming a 15-year equipment lifetime and a 7 percent interest rate, are $2,800 and $5,040, respectively for a system powered with electricity from the grid or other power source for small and medium-sized plants, and $3,090 and $5,630, respectively, for a solar-powered system for small and medium-sized plants.

For the production segment, considering the slightly more expensive solar-powered system, under the single pollutant approach, the estimated cost effectiveness is $550 per ton of methane avoided and $1,970 per ton of VOC avoided for a small plant and $500 per ton of methane avoided and $1,810 per ton of VOC avoided for a medium-sized plant. Using the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the estimated cost effectiveness is $275 per ton of methane avoided and $980 per ton of VOC avoided for a small plant and $250 per ton of methane avoided and $900 per ton of VOC avoided for a medium-sized plant in the production segment. When considering the cost of saving the natural gas that would otherwise be emitted for the production segment, the cost effectiveness is $370 per ton of methane avoided and $1,320 per ton of VOC avoided for a small plant and $320 per ton of methane avoided and $1,150 per ton of VOC avoided for a medium-sized plant. Using the multipollutant approach, the estimated cost effectiveness is $185 per ton of methane avoided and $660 per ton of VOC avoided for a small plant and $160 per ton of methane avoided and $580 per ton of VOC avoided for a medium-sized plant in the production segment. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

For the natural gas transmission and storage segment, considering the slightly more expensive solar-powered system, the estimated cost effectiveness is $750 per ton of methane avoided and $27,200 per ton of VOC avoided for a small plant and $990 per ton of methane avoided and $35,700 per ton of VOC avoided for a medium-sized plant. Using the multipollutant approach, the estimated cost effectiveness is $380 per ton of methane avoided and $13,600 per ton of VOC avoided for a small plant and $490 per ton of methane avoided and $17,800 per ton of VOC avoided for a medium-sized plant. Transmission and storage facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted/lost was not applied for this segment. While the cost effectiveness values for VOC are higher than the range of what the EPA considers to be reasonable for VOC, the cost effectiveness for methane is within the range of what the EPA considers to be reasonable for methane using the single pollutant approach.

For the large model plants, the zero-emissions option evaluated was the use of instrument air systems. For the production segment, the emissions avoided would be 24.9 tpy methane and 6.9 tpy VOC, and in the transmission and storage segment 10.0 tpy methane and 0.3 tpy VOC. The cost of a new instrument air system is estimated to be $96,000 and the estimated annualized capital costs, assuming a 15-year equipment lifetime and a 7 percent interest rate, are $10,500. For the production segment, under the single pollutant approach, the estimated cost effectiveness is $420 per ton of methane avoided and $1,520 per ton of VOC avoided. Using the multipollutant approach, the estimated cost effectiveness is $210 per ton of methane avoided and $760 per ton of VOC avoided. When considering the cost of saving the natural gas that would otherwise be emitted for the production segment, the cost effectiveness is $240 per ton of methane avoided and $860 per ton of VOC avoided. Using the multipollutant approach, the estimated cost effectiveness is $120 per ton of methane avoided and $430 per ton of VOC avoided in the production segment. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

For the natural gas transmission and storage segment, the estimated cost effectiveness is $1,050 per ton of methane avoided and $38,000 per ton of VOC avoided. Using the multipollutant approach, the estimated cost effectiveness is $530 per ton of methane avoided and $19,000 per ton of VOC avoided. Transmission and storage facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted/lost was not applied for this segment. While the cost effectiveness values for VOC are higher than the range of what the EPA considers to be reasonable for VOC, the cost effectiveness for methane is within the range of what the EPA considers to be reasonable for methane using the single pollutant approach.

Note that the annual costs for these zero-emissions controllers are based on the annualized capital costs only. While we assume the maintenance costs for electric controllers is less than the costs for natural gas-driven controllers, there are costs associated with the use of electricity that are not incurred for natural gas-driven controllers. We solicit comments on whether such operational costs should be included in these estimates, as well as information regarding these costs.

The capital costs of solar-powered controllers include the cost of the batteries, which represents around 7 percent of the total cost of a solar-powered system. As noted above, the capital cost was annualized assuming a 15-year lifetime, however batteries for a solar system may have a shorter life. We are soliciting comment on the life of these batteries and, if this life is shorter than 15 years, how the costs of these batteries should be included as a maintenance cost for solar powered systems.

The EPA finds that the cost effectiveness for both the low bleed and zero-emissions options are reasonable for sites in the production and natural gas transmission and storage segments. The incremental cost effectiveness in going from the low bleed option to the zero-emissions option is estimated to be $390 and $340 per ton of additional methane eliminated for small and medium-sized plants ($1,400 and $1,200 per ton of VOC), respectively, in the production segment and $640 and $870 per ton of additional methane eliminated for small and medium-sized plants ($23,000 and $31,500 per ton of VOC), respectively, in the transmission and storage segment. The incremental cost effectiveness in going from the low bleed option to the non-emissions option is estimated to be $260 and $940 per ton of additional methane and VOC avoided, respectively, for large plants in the production segment and to be $940 and $34,000 per ton of additional methane and VOC avoided, respectively, for large plants in the transmission and storage segment. These incremental costs of control do not consider savings for the production segment. The EPA believes the incremental costs of control are reasonable for methane and VOC in the production segment, and for methane in the transmission and storage segment.

As discussed above, several States and Canadian provinces require the use of controllers that do not emit methane or VOC throughout the Oil and Natural Gas Industry, which further demonstrates the reasonableness of this option and that there are no technical barriers inhibiting the use of electronic controllers or instrument air systems at sites in the production and transmission

and storage segments. In 2015, the EPA concluded that, ''[a]t sites without available electrical service sufficient to power an instrument air compressor, only gas driven pneumatic devices are technically feasible in all situations.'' (80 FR 56623, September 18, 2015). However, since that time, at least two States and two Canadian provinces have adopted regulations that require zero emitting controllers at all new sites. The EPA evaluated these rules, and considers these rules, along with the basic understanding that sources in these areas are able to comply with the rules, evidence that the feasibility issues that led to the EPA's previous decision not to require zero emission controllers in 2015 have been overcome. Further, the EPA recognizes that industry commenters on the proposed Colorado rule raised some of the same technical feasibility issues that have been presented to the EPA in the past, including battery storage capacity issues, weather-related issues, and mechanical issues related to vibration.[257] However, despite these issues being raised, Colorado finalized the requirement that new controllers have a natural gas bleed rate of zero at all sites, even though without power. The EPA has considered new information since 2016 and has now concluded that use of zero-emission controllers is technically feasible subject to a particular proposed exception discussed below. The EPA specifically requests comments on this conclusion. The EPA further solicits comment on market availability of zero-emission options.

Secondary impacts from the use of electronic controllers and instrument air systems are indirect, variable, and dependent on the electrical supply used to power the compressor or controllers. These impacts are expected to be minimal. For example, it is estimated that the electricity needed to operate a compressor is only around 0.4 kW/hour/controller when the compressor is operating. No other secondary impacts are expected. The EPA solicits comment on whether owners and operators would use diesel generators to generate power to run zero-emissions controllers. The EPA recognizes that diesel generators would generate formaldehyde emissions and there could be associated secondary impacts. The EPA does not intend for diesel generators to be used.

[257] Pneumatic Controller Task Force Report to the Air Quality Control Commission. Pneumatic Controller Field Study and Recommendations. Colorado Department of Public Health and Environment. Air Pollution Control Division. June 1, 2020.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven pneumatic controllers at production and transmission and storage sites is the use of zero-emissions controllers. Therefore, for NSPS OOOOb, we are proposing to require zero emissions of methane and VOC to the atmosphere for all pneumatic controllers at production and transmission and storage sites.

Both NSPS OOOO and NSPS OOOOa allow the use of high-bleed pneumatic controllers at production sites and natural gas-driven continuous bleed controllers at natural gas processing plants if it is determined that the use of such 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.'' See 40 CFR 60.5390(a) and 60.5390a(a). This exemption was based on comments received on the 2011 proposed NSPS OOOO rule. There, ''[t]he commenters suggest exemptions that address situations such as those where the natural gas includes impurities that could increase the likelihood of fouling a low-bleed pneumatic controller, such as paraffin or salts; where weather conditions could degrade pneumatic controller performance; during emergency conditions; where flow is not sufficient for low-bleed pneumatic controllers; where electricity is not available; and where engineering judgment recommends their use to maintain safety, reliability or efficiency.'' (77 FR 49520, August 16, 2012). These reasons to allow for an exemption based on functional need were based on the inability of a low-bleed controller to meet the functional requirements of an owner/operator such that a high-bleed controller would be required in certain instances. Since we are now proposing that nearly all pneumatic controllers have a methane and VOC emission rate of zero, subject to exemption explained below, we do not believe that the reasons cited above are still applicable. Therefore, the proposed rule does not include an exemption based on functional need. The EPA is requesting comment regarding the possibility of situations where functional requirements/needs dictate that a natural gas-driven controller that emits any amount of VOC and/or methane be used. For example, are there situations where a zero-emission controller cannot be used due to functional needs such that an owner/operator must use a low-bleed controller or an intermittent controller instead? Comments requesting such an exemption should include details of the specific functional need and why all zero-emission controller options are not suitable.

For many sites, the EPA believes that the most feasible zero-emission option will be solar-powered controllers. The EPA recognizes that solar-powered controllers are dependent on sunshine, and in areas at higher latitudes that undergo prolonged periods without sunshine, this option could be problematic to implement due to the technical limitations of solar panels coupled with the practical realities related to the hours of sunshine received. Therefore, the proposed rule includes an exemption from the zero-emission requirement for pneumatic controllers at sites in Alaska that do not have access to power (*i.e.,* electricity from the grid or produced using natural gas on-site). Sites with power have clearly demonstrated that zero emissions from controllers is achievable, and therefore the EPA is not proposing to exempt pneumatic controllers at sites in Alaska that have power. The proposed exemption would only apply to pneumatic controllers at sites located in Alaska that do not have access to power. In those situations, affected facilities would not be required to comply with the zero-emission standard, but instead must use low-bleed pneumatic controllers (unless a high bleed device is needed for functional reasons) and must monitor any intermittent controllers in conjunction with the fugitives monitoring program to ensure they are not venting when idle. The EPA is soliciting comment on this proposed exemption. Specifically, the EPA is interested in comments regarding the technical feasibility of solar panels to power pneumatic controllers in Alaska. The EPA is also interested in comments regarding whether there are other locations outside of Alaska where such an exemption may be warranted. In submitting responses to this request, commenters should be mindful that two Canadian Provinces, which are north of any U.S. State other than Alaska, require zero-emitting controllers at all new sites.

Natural Gas Processing Plants

Natural gas processing plants typically have higher numbers of pneumatic controllers than production and transmission and storage sites. Model plants were also used for this analysis, specifically the model plants used are the same as those used for the 2011 and 2015 BSER analyses, and include small, medium, and large sites.

The number of controllers is 15, 63, and 175 for small, medium, and large model plants, respectively. All controllers at these sites are assumed to be continuous, but the number of low bleed and high bleed devices is not specified for the model plants. It was assumed that each controller emitted 1 tpy methane, as derived from Volume 12 of a 1996 GRI report.[258] In addition, it was assumed that the portion of natural gas that is methane is 82.8 percent in the natural gas processing segment, and the specific VOC to methane ratio assumed was 0.278 pounds VOC per pound methane. For detailed information on the configuration of these model plants, see the NSPS OOOOb and EG TSD, which is available in the docket.

For natural gas processing plants, the only option evaluated was the requirement to use zero-emission controllers. For our analysis, we examined the use of instrument air, which is the most commonly used controller technology at natural gas processing plants. For this analysis, we used cost data from the 2011 NSPS OOOO TSD updated to 2019 dollars. The updated capital costs for an instrument air system at a natural gas processing plant ranges from $20,000 to $162,000, depending on the system size. The annualized costs were based on a 7 percent interest rate and a 10-year equipment life. This equated to an annualized cost of approximately $13,000 to $96,000 per system. The emissions reduction associated with the installation of an instrument air system over natural gas-driven pneumatic controllers ranged from approximately 15 to 175 tpy methane and 4.2 to 49 tpy VOC per system. The cost effectiveness is estimated to range from approximately $550 to $900 per ton methane eliminated $2,000 to $3,100 per ton VOC eliminated. When considering the costs of saving the natural gas that would otherwise be emitted, the cost effectiveness improves, with a cost effectiveness of $370 to $700 per ton of methane eliminated and $1,300 to $2,500 per ton of VOC eliminated. These cost effectiveness values are presented on a single pollutant basis, and the cost of control on a multipollutant basis is 50 percent of these values. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

The 2012 NSPS OOOO and 2016 NSPS OOOOa require a zero-bleed emission rate for pneumatic controllers at natural gas processing plants. Natural gas processing plants have successfully met this standard for many years now. Further, several State agencies have rules that include this zero-bleed requirement for controllers at natural gas processing plants. This is further demonstration of the reasonableness of a zero methane and VOC emission standard for pneumatic controllers at natural gas processing plants.

We find the cost effectiveness of eliminating methane and VOC emissions using both the single pollutant and multipollutant approaches to be reasonable.

Secondary impacts from the use of instrument air systems are indirect, variable, and dependent on the electrical supply used to power the compressor. These impacts are expected to be minimal, and no other secondary impacts are expected.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven pneumatic controllers at natural gas processing plants is the use of zero-emissions controllers. Therefore, for NSPS OOOOb, we are proposing to require a natural gas emission rate of zero for all pneumatic controllers at natural gas processing plants. However, we recognize that there may be technical limitations in some situations where zero-emissions controllers may not be feasible, and therefore, we are proposing an allowance for the use of natural gas-driven pneumatic controllers with an emission rate of methane and VOC greater than zero where needed due to functional requirements in this BSER determination. Justification of this functional need must be provided in an annual report and maintained in records.

f. Use of Combustion Devices and VRUs

Another option that could potentially be used to reduce emissions from pneumatic controllers is to collect the emissions from natural gas driven continuous bleed controllers and intermittent vent controllers and route the emissions through a closed vent system to a control device or process. This option is allowed in some State rules. While the EPA did not evaluate the cost effectiveness of this option due to a lack of available information regarding control system costs and feasibility across sites, we think this option could be cost effective for owners and operations in certain situations, particularly if the site already has a control device to which the emissions from controllers could be routed. As this option could be used to achieve significant methane and VOC emission reductions (95 percent or greater), we are soliciting comment on whether this is a control technique used in the industry to reduce emissions from natural gas-driven pneumatic controllers. We are also interested in information related to the performance testing, monitoring, and compliance requirements associated with these control devices. Finally, we are interested in ideas as to how this option could potentially fit with the proposed requirements for pneumatic controllers. For example, if an owner or operator determines that a natural gas-driven pneumatic controller is required for functional need reasons, the EPA could require that emissions be collected and routed to a control device that achieves 95, or 98, percent control.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing pneumatic controllers (designated facilities) in all segments in the Crude Oil and Natural Gas source category covered by the proposed NSPS OOOOb and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities that essentially mirrors the proposed NSPS OOOOb.

First, based on the same criteria and reasoning as explained above, the EPA is proposing to define the designated facilities in the context of existing pneumatic controllers as those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should change these definitions as applied to existing sources. As such, for purposes of the emission guidelines, the definition of a designated facility in terms of pneumatic controllers is each individual natural gas driven pneumatic controller (continuous bleed or intermittent vent) that vents to the atmosphere.

Next, the EPA finds that the control options evaluated for new sources for NSPS OOOOb are appropriate for consideration in the context of existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission

[258] Radian International LLC. *Methane Emissions from the Natural Gas Industry*, Vol. 12: Pneumatic Devices. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA–600/R–96–080k. June 1996.

reduction, for pneumatic controllers that could be used for existing sources but not for new sources.

Next, the methane emission reductions expected to be achieved via application of the control measures identified above for new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

For the most part, the information presented above regarding the costs related to new sources and the NSPS are also applicable for existing sources. The instance where the EPA estimated a difference in the costs between a new and existing source was for the retrofit of an existing production site to use instrument air at sites equipped with electrical power. While the equipment needed is the same as for new sites, it may be more difficult to design and install a retrofitted system. Therefore, the EPA estimates the costs for design and installation to be twice that of the costs for new systems (from approximately $32,000 for new systems to approximately $64,000 for existing systems), resulting in the capital cost of the system being approximately $127,000 with an annualized cost of approximately $14,000.

As noted above, the EPA's analysis for this proposal only examined the cost of instrument air for the large model plant. The total elimination of methane emissions (25 tons per year methane for production sites and 10 tons per year methane for transmission and storage sites) would be the same for existing sources as presented above for new sources. Considering the cost difference, the cost effectiveness for production sites is $560 per ton of methane eliminated without considering savings, and $365 per ton when considering savings. For the transmission and storage segment, the cost effectiveness is $1,400 per ton of methane eliminated. These values are within the range of what the EPA considers to be reasonable for methane. Since none of the other factors are different for existing sources when compared to the information discussed above for new sources, the EPA concludes that BSER for existing sources and the proposed presumptive standard for EG OOOOc to be the requirement to use zero-emission controllers. This proposed EG includes the exemption from the zero-emission standard for pneumatic controllers in Alaska as explained above in the context of the proposed NSPS OOOOb.

b. Possible Phase-In Approach for Existing Sources

The EPA recognizes there could be different compliance time approaches that could be implemented for existing pneumatic controllers. The EPA's proposal for compliance times State plans must include to meet the requirements of the EG can be found in Section XIV.E. As explained there, the EPA is proposing that State plans must generally include a 2-year timeline for compliance in the proposed EG, but is also soliciting comment on the possibility of the EG requiring different compliance timelines for different emission points. Specifically, in the context of pneumatic controllers, the EPA is further soliciting comment on including a phase-in approach in the EG. The EPA recognizes that a phase-in approach may only be appropriate for existing sources as new facilities could presumably plan for zero-emission controllers during construction. A phase-in period could span a number of years (*e.g.,* 2 years), to allow owners and operators to prioritize conversion of natural gas-driven controllers at existing sites based on specific factors (*e.g.,* focus first on sites with onsite power, sites with highest production, sites with the highest number of controllers). A phase-in approach could also result in the conversion of a certain percentage of sites within a given area (*e.g.,* State or basin). For example, the State of Colorado requires a minimum of 40 percent of sites to be converted after 2 years, with 15 percent in year 1 and 25 percent in year 2. The EPA also recognizes potential challenges with a phase-in approach, such as difficulties with enforcement and calculation of the percentage converted due to the frequency at which sites may change ownership. The EPA solicits comment on all aspects of the EG requiring State plans to include a phase-in approach, and whether the agency should consider this type of approach rather than a single compliance time. The EPA also solicits comment on cost and feasibility factors that would enter into adopting and designing a phase-in timeline.

c. Natural Gas Processing Plants

The information presented above regarding the emissions, emission reduction options and their effectiveness, costs, and other factors related to new natural gas processing plants and the NSPS are also applicable for existing sources. Therefore, the EPA concludes that BSER for existing sources and the EG OOOOc for natural gas processing plants is the requirement to use zero-emission controllers.

D. Proposed Standards for Well Liquids Unloading Operations

1. NSPS OOOOb

a. Background

In the 2015 NSPS OOOOa proposal (80 FR 56614–56615, September 18, 2015), the EPA stated that based on available information and input received from stakeholders on the 2014 *Oil and Natural Gas Sector Liquids Unloading Processes* review document,[259] sufficient information was not available to propose a standard for liquids unloading.

At that time, the EPA requested comment on technologies and techniques that could be applied to new gas wells to reduce emissions from liquids unloading events in the future. In the 2016 NSPS OOOOa final rule (81 FR 35846, June 3, 2016), the EPA stated that, although the EPA received valuable information from the public comment process, the information was not sufficient to finalize a national standard representing BSER for liquids unloading at that time.

For this proposal, the EPA conducted a review of available information, including new information that became available after the 2016 NSPS OOOOa rulemaking. As a result of this review, the EPA is proposing a zero VOC and methane emission standard under NSPS OOOOb for liquid unloading, which can be achieved using non-venting liquids unloading methods. In the event that it is technically infeasible or not safe to perform liquids unloading with zero emissions, the EPA is proposing to require that an owner or operator establish and follow BMPs to minimize methane and VOC emissions during liquids unloading events to the extent possible. These proposed requirements apply to each well liquids unloading event.

An overall description of liquids unloading, the definition of a modification, the definition of affected facility, our BSER analysis, and the proposed format of the standard are presented below.

[259] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Liquids Unloading Processes.* Report for Oil and Natural Gas Sector. Liquids Unloading Processes Review Panel. April 2014.

b. Description

In new gas wells, there is generally sufficient reservoir pressure/gas velocity to facilitate the flow of water and hydrocarbon liquids through the well head and to the separator to the surface along with produced gas. In mature gas wells, the accumulation of liquids in the wellbore can occur when the bottom well pressure/gas velocity approaches the average reservoir pressure (*i.e.,* volumetric average fluid pressure within the reservoir across the areal extent of the reservoir boundaries).[260] This accumulation of liquids can impede and sometimes halt gas production. When the accumulation of liquids results in the slowing or cessation of gas production (*i.e.,* liquids loading), removal of fluids (*i.e.,* liquids unloading) is required in order to maintain production. These gas wells therefore often need to remove or ''unload'' the accumulated liquids so that gas production is not inhibited.

The 2019 U.S. GHGI estimates almost 175,800 metric tpy of methane emissions from liquids unloading events for natural gas systems. Specifically, this includes almost 175,800 metric tpy from natural gas production, 98,900 metric tpy of which is from liquids unloading events that use a plunger lift, and 76,900 metric tpy from liquids unloading events that do not use a plunger lift. The overall total represents 3 percent of the total methane emissions estimated from natural gas systems.

In addition to the GHGI information, we also examined the information submitted under GHGRP subpart W. Specifically, we examined the GHGRP subpart W liquids unloading emissions data reported for Reporting Years 2015 to 2019. The liquids unloading emissions reported under GHGRP subpart W include emissions from venting wells, including those wells that vent during events that use a plunger lift and wells that vent during events that do not use a plunger lift. The information reported shows that methane emissions from liquids unloading for a well range from 0 to over 1,000 metric tons (1,100 tons) per year. While the single well with liquids unloading emissions of 1,100 tpy appears to be an outlier, there were over 65 subbasins with reported average liquids unloading emissions of 50 tpy or greater per well when disaggregating data by year and calculation method. There were over 1,000 wells reporting in these subbasins. In addition, there were almost 300 sub-basins with reported average liquids unloading methane emissions of 10 tpy or greater per well. There were almost 8,000 wells reporting in these subbasins.

Another source of information reviewed related to emissions information from liquids unloading was a study published in 2015 by Allen, et al. (University of Texas (UT) Study).[261] [262] The UT Study collected monitoring data across regions of the U.S. Among other findings in this report, for wells that vent more than 100 times per year, the average methane emissions per well per year were 27 metric tpy, with 95 percent confidence bounds of 10 to 50 Mg/yr (based on the confidence bounds in the emissions per event). The monitoring data shows that methane emissions from liquids unloading for a well range from 1 to 19,500 Mscf per year, or 0.02 to 406 tpy.[263] As indicated by the UT study [264] emissions information, a small fraction of wells account for a large fraction of liquids unloading emissions.

c. Modification

As noted in section XII.D.1.b, new wells typically do not require liquids unloading until the point that the accumulation of liquids impedes or even stops gas production. At that point, the well must be unloaded of liquids to improve the gas flow. One method to accomplish this involves the intentional manual venting of the well to the atmosphere to improve gas flow. This is done using various techniques. One common manual unloading technique diverts the well's flow, bypassing the production separator to a lower pressure source, such as an atmospheric pressure tank. Under this scenario, venting to the atmospheric tank occurs because the separator operates at a higher pressure than the atmospheric tank and the well will temporarily flow to the atmospheric tank (which has a lower pressure than the pressurized separator). Natural gas is released through the tank vent to the atmosphere until liquids are unloaded and the flow diverted back to the separator. As discussed later in this section, the EPA has received feedback that there are technical difficulties with flaring vented emissions as a result of the intermittent and surging flow characteristic of venting for liquids unloading, and the changing velocities during an unloading event.

Since each unloading event constitutes a physical or operational change to the well that has the potential to increase emissions, the EPA is proposing to determine each event of liquids unloading constitutes a modification that makes a well an affected facility subject to the NSPS. See 40 CFR 60.14(a) (''any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act''). The EPA solicits comment on this determination.

d. Definition of Affected Facility

Given that we have proposed to determine that every liquids unloading event is a modification, the next step is to define the affected facility. The EPA recognizes that methods are commonly employed that significantly reduce, or even eliminate, emissions from liquids unloading. Therefore, the EPA is co-proposing two options on how a modified well due to a liquids unloading event would be covered under the rule.

Under the first option, the affected facility subject to the requirements of NSPS OOOOb would be defined as every well that undergoes liquids unloading after the effective date of the final rule. Under this scenario, a well that undergoes liquids unloading is an affected facility regardless of whether the liquids unloading approach used results in venting to the atmosphere. This option posits that techniques employed to unload liquids that do not increase emissions are not to be considered in whether the unloading event is an affected facility or not, since the liquids unloading event in their absence could result in an emissions increase. This is somewhat analogous to a physical change to an existing storage vessel that resulted in the ability to increase throughput, and thus emissions. This physical change could result in an increase in emissions even if emissions were captured and routed back to a process such that the level of pollutant actually emitted to the atmosphere did not change. Under this scenario, the EPA could request and obtain compliance and enforcement information on non-venting liquids

[260] Gordon Smith Review. *Oil & Natural Gas Sector Liquids Unloading Processes.* Submitted: June 16, 2014. Pg. 4.

[261] D.T. Allen, D.W. Sullivan, D. Zavala-Araiza, A.P. Pacsi, M. Harrison, K. Keen, M.P. Fraser, A. Daniel Hill, B.K. Lamb, R.F. Sawyer, J.H. Seinfeld, *Methane emissions from process equipment at natural gas production sites in the United States: Liquid unloadings.* Environ. Sci. Technol. 49, 641–648 (2015). doi:10.1021/es504016r Medline. (UT Study).

[262] D.T. Allen, D.W. Sullivan, D. Zavala-Araiza, A.P. Pacsi, M. Harrison, K. Keen, M.P. Fraser, A. Daniel Hill, B.K. Lamb, R.F. Sawyer, J.H. Seinfeld. *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings—Supporting Information;* (UT Study—SI). Table S5–1, pg. 21.

[263] UT Study—SI. Tables S3–1 to S3–3, pgs. 11–14.

[264] UT Study. pg. 642.

unloading event methods commonly employed (simple records and reporting requirements), as well as venting liquids unloading events.

Under the second option, the affected facility would be defined as every well that undergoes liquids unloading using a method that is not designed to totally eliminate venting (*i.e.,* that results in emissions to the atmosphere). Under this scenario, if an owner or operator employs a method to unload liquids that does not vent to the atmosphere, the liquids unloading event would not constitute an increase in emissions and therefore, the well would not be an affected facility. As such, the first liquids unloading event that vents to the atmosphere after the effective date of the final rule, would be an affected facility subject to the requirements of NSPS OOOOb. This option could create an enforcement information and compliance gap. Specifically, the EPA would not be able to obtain compliance assurance information on liquids unloading events and emissions/methods and there could be a decreased incentive for owners or operators to ensure that no unexpected emission episodes occur when a method designed to be non-venting is used.

The EPA solicits comments on the two affected facility definition options being co-proposed. Specifically, we request comment on whether there are implementation and/or compliance assurance concerns that arise with applying either of the co-proposed options. In addition, we request comment on if there are any appropriate exemptions for operations that may be unlikely to result in emissions, such as wellheads that are not operating under positive pressure.

e. 2021 BSER Analysis

The choice of what liquids unloading technique to employ is based on an operator well-by-well and reservoir-by-reservoir engineering analysis. Because liquids unloading operations entail a number of complex science and engineering considerations that can vary across well sites, there is no single technological solution or technique that is optimal for liquids unloading at all wells. Rather, a large number of differing technologies, techniques and practices (*i.e.,* ''methods'') have been developed to address the unique characteristics of individual wells so as to manage liquids and maintain production. These methods include, but are not limited to, manual unloading, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps, intermittent unloading, gas lift (*e.g.,* use of a plunger lift), foam agents, wellhead compression, and routing the gas to a sales line or back to a process.

Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production. The situation is further complicated as the best method for a particular well can change over time. At the onset of liquids loading, techniques that rely on the reservoir energy are typically used. Eventually a well's reservoir energy is not sufficient to remove the liquids from the well and it is necessary to add energy to the well to continue production.

In the 2016 NSPS OOOOa final rule preamble, the EPA acknowledged that operators must select the technique to perform liquids unloading operations based on the conditions of the well each time production is impaired. During the development of the 2016 NSPS OOOOa rule, the EPA considered subcategorization based on the potential for well site liquids unloading emissions but determined that the differences in liquids unloading events (with respect to both frequency and emissions level) are due to specific conditions of a given well at the time the operator determines that well production is impaired such that unloading must be done. Since owners and operators must select the technique to perform an unloading operation based on those conditions, and because well conditions change over time, each iteration of unloading may require repeating a single technique or attempting a different technique that may not have been appropriate under prior conditions. As noted above, we recognized that the choice of method to unload liquids from a well needs to be a production engineering decision based on the characteristics of the well at the time of the unloading, and owners and operators need the flexibility to select a method that is effective and can be safely employed. No information has become available since 2016 that leads the EPA to reach a different conclusion regarding subcategorization of wells for the purpose of developing standards to address liquids unloading emissions. Further, the EPA acknowledges the need for owners and operators to have the flexibility to select the most appropriate method(s) and recognize that any standard must not impede this flexibility.

Many methods used for liquids unloading do not result in any venting to the atmosphere, provided that the method is properly executed. High-level summaries of a few of these methods are provided below.[265]

A commonly used method employed in the field is the use of a plunger lift system. While plunger lift systems often are used in a way to minimize emissions, under certain conditions they can be operated to unload liquids in a manner that eliminates the need to vent to the atmosphere. Plunger lifts use the well's own energy (gas/pressure) to drive a piston or plunger that travels the length of the tubing in order to push accumulated liquids in the tubing to the surface. Specific criteria regarding well pressure and liquid to gas ratio can affect applicability. Candidate wells for plunger lift systems generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system. Optimized plunger lift systems (*e.g.,* with smart well automation) can decrease the amount of gas vented by up to and greater than 90 percent, and in some instances can reduce the need for venting due to overloading. Plunger lift costs range from $1,900 to $20,000.[266] Adding smart automation can cost anywhere between an estimated $4,700 to $18,000 depending on the complexity of the well. Natural Gas STAR estimates that the annual cost savings from avoided emissions from the use of an automated system ranges anywhere between $2,400 and $10,241 per year.[267]

Other artificial lifts (*e.g.,* rod pumps, beam lift pumps, pumpjacks and downhole separator pumps) are typically used when there is inadequate pressure to use a plunger lift, and the only means of liquids unloading to keep gas flowing is downhole pump technology. Artificial lifts can be operated in a manner that produces no emissions. The use of an artificial lift requires access to a power source. The capital and installation costs (including location preparation, well clean out, artificial lift equipment and pumping unit) is estimated to be $41,000 to $62,000/well, with the average cost of a pumping unit being between $17,000 to $27,000. [268]

[265] ''Oil and Natural Gas Sector Liquids Unloading Processes''. Report for Oil and Natural Gas Sector Liquids Unloading Processes Review Panel. Prepared by U.S. EPA OAQPS. April 2014.

[265] 80 FR 56593, September 18, 2015.

[266] U.S. Environmental Protection Agency. *Installing Plunger Lift Systems in Gas Wells.* Office of Air and Radiation: Natural Gas Star Program. Washington, DC. 2006.

[267] U.S. Environmental Protection Agency. (U.S. EPA) 2011. *Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.* Office of Air and Radiation: Natural Gas Star Program. Washington, DC. 2011. pg. 1.

[268] U.S. EPA, 2011. pg. 9.

Velocity tubing is smaller diameter production tubing that reduces the cross-sectional area of flow, increasing the flow velocity and achieving liquids removal without blowing emissions to the atmosphere. Generally, a gas flow velocity of 1,000 feet per minute (fpm) is necessary to remove wellbore liquids. Velocity tubing strings are appropriate for low volume natural gas wells upon initial completion or near the end of their productive lives with relatively small liquids production and higher reservoir pressure. Candidate wells include marginal gas wells producing less than 60 Mcfd. Similarly, coil tubing can also be used in wells with lower velocity gas production (*i.e.,* seamed coiled tubing may provide better lift due to elimination of turbulence in the flow stream). The proper use of velocity tubing is considered to be a ''no emissions'' solution. It is also low maintenance and effective for low volumes lifted. Velocity lifting can be deployed in combination with foaming agents (discussed below). The capital and installation costs are estimated to range anywhere from $7,000 to $64,000 per well.[269] Installation requires a well workover rig to remove existing production tubing and placement of the smaller diameter tubing string in the well.

The use of foaming agents (soap, surfactants) as a method to unload liquids is implemented by the injection of foaming agents in the casing/tubing annulus by a chemical pump on a timer basis. The gas bubbling of the soap-water solution creates gas-water foam which is more easily lifted to the surface for water removal. This, like the use of artificial lifts, requires power to run the surface injection pump. Additionally, foaming agents work best if the fluid in the well is at least 50 percent water and are not effective for natural gas liquids or liquid hydrocarbons. This method requires that the soap supply be monitored. If the well is still unable to unload fluid, smaller tubing may be needed to help lift the fluids. Foaming agents and velocity tubing are reported as possibly being more effective when used in combination. No equipment is required in shallow wells. In deep wells, a surfactant injection system requires the installation of surface equipment and regular monitoring. Foaming agents are reported as being low cost ''no emissions'' solution. The capital and startup costs to install soap launchers and velocity tubing is estimated to range between $7,500 and $67,880, with the monthly cost of the foaming agent is approximately $500 per well or approximately $6,000 per year.[270]

These are just a few examples of demonstrated methods that are being used in the industry to unload accumulated liquids that impair production, that can be implemented without venting and, thus, without emissions. As stressed earlier, the selection of a specific method must be made based on well-specific characteristics and conditions.

Since GHGRP subpart W only requires reporting of liquids unloading events that resulted in venting of methane, no information is submitted regarding those wells that utilize a non-venting method. The EPA is also not aware of information that specifies the total number of wells that need to undergo liquids unloading. A 2012 report sponsored by the API and American Natural Gas Alliance (ANGA)[271] provided more definitive insight into the number of wells that use non-venting liquids unloading methods. This report indicated that an estimated 21.1 percent of plunger equipped wells vent, and 9.3 percent of non-plunger equipped wells vent. The EPA interprets this to mean that almost 80 percent of plunger-equipped wells, and over 90 percent of non-plunger-equipped wells perform liquids unloading and utilize non-venting methods.

As noted above, there is a tremendous range in the emissions from liquids unloading reported for individual wells. Further, as discussed above, the costs for the non-venting methods range considerably. Also, as discussed above, we have determined that the myriad of possible reservoir conditions and unloading methods do not lend to any reasonable subcategorization of the industry for which representative wells could be designed. Therefore, it is not possible to develop a ''model'' well, or even a series of model wells, that can be used to conduct the type of analysis frequently performed for BSER determinations that calculates a cost per ton of emissions reduced (or in this case eliminated).

Based on the highest costs included in the cost examples provided above, the cost effectiveness of a non-venting method would be considered reasonable for wells with annual methane emissions from liquids unloading of 16 tpy or greater, or VOC emissions of 3 tpy or greater. This upper range is based on the cost of the combination of velocity tubing and soap launchers. The upper range of the capital cost cited above was $67,800. Annualizing this capital cost at a 7 percent interest rate over 10 years, and adding in the $6,000 per year foaming agent cost, results in a total annual cost of $15,600. Given the total elimination of emissions, the cost effectiveness for a well with 16 tpy methane emissions would be $980 per ton of methane reduced, which is a level that the EPA considers reasonable for methane. Similarly, for VOC, the cost effectiveness for a well with 3 tpy VOC emissions would be $5,200 per ton of VOC reduced. This is also a level that the EPA considers reasonable. Given the range of costs, it could be reasonable even for some wells with annual liquids unloading methane emissions as low as 2.5 tpy ($400 per ton of methane reduced (velocity tubing)), or VOC emissions as low as 0.2 tpy ($5,000 per ton of VOC reduced (velocity tubing)). Based on the GHGRP subpart W data for the years 2015 through 2019, around 50 percent of the wells that performed liquids unloading and reported emissions reported emissions higher than these levels.

While owners and operators must select a liquids unloading method that is applicable for the well-specific conditions, they have the choice of many methods that can be used to eliminate venting/emissions from liquids unloading events. While we do not have information to calculate the specific percentage of total wells undergoing liquids unloading that use non-venting methods, available information suggests that a majority of wells that undergo liquids unloading do not vent. The EPA solicits information on the number (or percent) of liquids unloading events that vent to the atmosphere versus do not vent to the atmosphere under normal conditions and whether there are technical obstacles (other than costs) that would not allow liquids unloading to be performed without venting.

CAA section 111(a) requires that the standard reflect the BSER that the EPA determines ''has been adequately demonstrated.'' An ''adequately demonstrated system'' is one that ''has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' *Essex Chem.,* 486 F.2d at 433. For the reasons explained above and further elaborated below, the EPA considers non-venting methods such as those described above

[269] U.S. EPA, 2011. pg. 8.

[270] U.S. EPA. 2011. Pg. 8.

[271] Shires, T. URS Corporation and Lev-On, M. the LEVON Group. *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production.* Summary and Analysis of API and ANGA Survey Responses. Prepared for the American Petroleum Institute and the American Natural Gas Alliance. September 21, 2012.

to have been adequately demonstrated as the BSER for liquids unloading events. The complete elimination of emissions from liquids unloading with these non-venting methods have been adequately demonstrated in practice. The EPA notes that as part of decisions regarding liquids unloading, one goal of owners and operators is to eliminate venting to prevent the loss of product (natural gas) that could be routed to the sales line. States currently encourage the use of methods to eliminate emissions unless venting of emissions is necessary for safety reasons or when it is technically infeasible to not vent to unload liquids from the wellbore. For example, Pennsylvania has a general plan approval and/or general operating permit application (BAQ–GPA/GP–5A) that specifies that an owner or operator that conducts wellbore liquids unloading operations shall use best management practices including, but not limited to, plunger lift systems, soaping, swabbing, unless venting is necessary for safety to mitigate emissions during liquids unloading activities (Best Available Technology (BAT) Compliance Requirements under Section L of the General Permit).

As discussed previously, a majority of wells already conduct liquids unloading operations without venting to the atmosphere. Also, as discussed previously, there are multiple non-venting liquids unloading methods that an owner and operator can select based on a well's specific characteristics and conditions. Our evaluation of costs shows that there are non-venting liquids unloading methods that could be employed to unload liquids that are reasonable given a wide range of emission levels. Finally, there are no negative secondary environmental impacts that would result from the implementation of methods that would eliminate venting of methane and VOC emissions to the atmosphere. In light of the above, the EPA considers non-venting liquids unloading methods to have been adequately demonstrated to represent BSER for reducing methane and VOC emissions during liquids unloading events.

An ''adequately demonstrated'' system needs not be one that can achieve the standard ''at all times and under all circumstances.'' *Essex Chem.,* 486 F.2d at 433. That said, as discussed below, the EPA recognizes that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible.

The EPA recognizes that there may be safety and technical reasons why venting to the atmosphere is necessary to unload liquids. In addition, it is possible that a well production engineer has already explored non-venting options and determined that there was no feasible option due to its specific characteristics and conditions. For scenarios where a liquids unloading method employed requires venting to the atmosphere, the EPA evaluated requiring BMPs that would minimize venting to the maximum extent possible. There are several States that require the development and implementation of BMPs that minimize emissions from liquids unloading events that vent. For example, Colorado requires specified BMPs to eliminate or minimize vented emissions from liquids unloading. The rule requires that all attempts be made to unload liquids without venting unless venting is required for safety reasons. If venting is required, the rule requires that owners and operators be on site and that they ensure that any venting is limited to the maximum extent practicable. Specific BMPs evaluated are based on State rules that require BMPs to minimize emissions during liquids unloading events are to require operators to monitor manual liquids unloading events onsite and to follow procedures that minimize the need to vent emissions during an event. This includes following specific steps that create a differential pressure to minimize the need to vent a well to unload liquids and reducing wellbore pressure as much as possible prior to opening to atmosphere via storage tank, unloading through the separator where feasible, and requiring closure of all well head vents to the atmosphere and return of the well to production as soon as practicable. For example, where a plunger lift is used, the plunger lift can be operated so that the plunger returns to the top and the liquids and gas flow to the separator. Under this scenario, venting of the gas can be minimized and the gas that flows through the separator can be routed to sales. In situations where production engineers select an unloading technique that results or has the potential to vent emissions to the atmosphere, owners and operators already often implement BMPs in order to increase gas sales and reduce emissions and waste during these (often manual) liquids unloading activities. We performed a cost and impacts evaluation of the use of BMPs to reduce emissions from liquids unloading. This evaluation is provided in the NSPS OOOOb and EG TSD for this rulemaking.

Another potential method for reducing emissions from liquids unloading is to capture the vented gas from an unloading event and route it to a control device. At the time the Crude Oil and Natural Gas Sector Liquids Unloading Processes draft review document was submitted to reviewers, the EPA noted that, although the EPA was not aware of any specific instances where combustion devices/flares were used to control emissions vented from unloading events, the EPA requested information on the technical feasibility of flaring as an emissions control option for liquids unloading events. Feedback received from reviewers indicated that there are technical reasons that flaring during liquids unloading is not a feasible option.[272] Reviewers emphasized that, in order to flare gas during liquids unloading, the liquids would need to be separated from the well stream, and the intermittent and surging flow characteristics of venting for liquids unloading, changing velocities during an unloading, and flare ignition considerations for a sporadically used flare (*i.e.,* would require either a continuous pilot or electronic igniter) would make use of a flare technically and financially infeasible.[273] [274] The reviewers indicated that separating the liquids from the well stream would require the well stream to flow through a separator with sufficient backpressure to separate the gas and liquids. One reviewer noted that after separating the liquids from the well stream the gas would then be piped to flare system, where the backpressure needed to operate the separator would affect the performance of a plunger lift system (if used). Based on feedback received on the technical and cost feasibility of using a flare to control vented emissions from liquids unloading events indicating that a flare cannot be used in all situations, we did not consider this option any further in this proposal. However, the EPA is soliciting comments about the use of control devices to reduce emissions from liquids unloading events. Specifically, we request information on the types of wells and unloading events for which routing to control is feasible

[272] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Liquids Unloading Processes.* Report for Crude Oil and Natural Gas Sector. Liquids Unloading Processes Review Panel. April 2014.

[273] Gordon Smith Review. *Oil and Natural Gas Sector Liquids Unloading Processes.* Review Submitted: June 16, 2014. Pg. 31.

[274] Jim Bolander, P.E., Senior Vice President, Southwestern Energy (SWN). Review Submitted: April 2014. Pg. 8.

and effective, the level of emission reduction achieved, and the testing and monitoring requirements that apply.

A similar potential method is to capture the vented gas from an unloading event and route it to the sales line or back to a process. This could potentially represent another method that results in zero emissions. While this is not a mitigation option that has been specifically mentioned for emissions from liquids unloading, it is a common option for other emission sources in the oil and natural gas production segment. The EPA is soliciting comments about the option to collect and route emissions back to the sales line or to a process. Specifically, we request information on the types of wells and unloading events for which this option is feasible (if any). If this option is feasible, we also request information on the specifics of the equipment and processes needed to accomplish this, as well as the costs.

In conclusion, the EPA evaluated several options and identified the use of non-venting methods as the BSER for reducing methane and VOC emissions during liquids unloading events. However, the EPA recognizes there could be situations where it is infeasible to utilize a non-venting method. Therefore, the EPA proposes to allow for the development and implementation of BMPs to reduce emissions to the extent possible during liquids unloading where it is infeasible to utilize a non-venting method.

f. Format of the Standard

As discussed under section XII.D.1.d of this preamble, the EPA is co-proposing two regulatory approaches to implement the BSER determination.

For Option 1, the affected facility would be defined as every well that undergoes liquids unloading. This would mean that wells that utilize a non-venting method for liquids unloading would be affected facilities and subject to certain reporting and recordkeeping requirements. These requirements would include records of the number of unloadings that occur and the method used. A summary of this information would also be required to be reported in the annual report. The EPA also recognizes that under some circumstances venting could occur when a selected liquids unloading method that is designed to not vent to the atmosphere is not properly applied (*e.g.,* a technology malfunction or operator error). Under the proposed rule Option 1 owners and operators in this situation would be required to record and report these instances, as well as document and report the length of venting and what actions were taken to minimize venting to the maximum extent possible.

For wells that utilize methods that vent to the atmosphere, the proposed rule would require that they: (1) Document why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons; (2) develop BMPs that ensure that emissions during liquids unloading are minimized; (3) follow the BMPs during each liquids unloading event and maintain records demonstrating they were followed; (4) report the number of liquids unloading events in an annual report, as well as the unloading events when the BMP was not followed. While the proposed rule would not dictate the specific practices that must be included, it would specify minimum acceptance criteria required for the types and nature of the practices. Examples of the types and nature of the required practice elements for BMP are provided in section XII.D.1.e, such as those contained in Colorado's rule. The EPA is specifically requesting comment on the minimum elements that should be required in BMPs and the specificity that the proposed rule should include regarding these elements.

An advantage of this regulatory option is that it would provide information to the EPA on the number of liquids unloading events that occur and the types of unloading methods used. Having this important information would enhance the EPA, the industry, and the public's knowledge of emissions from liquids unloading. Option 1 would also provide incentive for owners and operators to ensure that non-venting methods are applied as they are designed such that unexpected emissions do not occur as the result of technology malfunctions or operator error. However, it would result in some recordkeeping and reporting burden for wells that already use or plan to use non-venting methods that would not be incurred under Option 2.

For Option 2, the affected facility would be defined as every well that undergoes liquids unloading using a method that is not designed to eliminate venting. The significant difference in this option is that wells that utilize non-venting methods would not be affected facilities that are subject to the NSPS OOOOb. Therefore, they would not have requirements other than to maintain records to demonstrate that they used non-venting liquids unloading methods. The requirements for wells that use methods that vent would be the same as described above under Option 1.

The EPA believes that this option would provide additional incentive for owners and operators to seek ways to overcome potential infeasibility issues to ensure that their wells are not affected facilities and subject to reporting and recordkeeping requirements. This would ultimately result in lower emissions. However, this would not provide the EPA information to have a more comprehensive understanding of emissions and emission reduction methods from liquids unloading. It would also not provide incentive for owners and operators to ensure that no unexpected emission episodes occur when a method designed to be non-venting is used.

2. EG OOOOc

As described above, the EPA is proposing that each unloading event represents a modification, which will make the well subject to new source standards under NSPS. Therefore, existing wells that undergo liquids unloading would become subject to NSPS OOOOb. This will mean that there will never be a well that undergoes liquids unloading that will be ''existing'' for purposes of CAA section 111(d). Therefore, there is no need for emissions guidelines or an associated presumptive standard under EG OOOOc for liquids unloading operations.

E. Proposed Standards for Reciprocating Compressors

1. NSPS OOOOb

a. Background

The 2012 NSPS OOOO and the 2016 NSPS OOOOa applied to each individual new or reconstructed reciprocating compressor, except for those compressors located at a well site, or those located at an adjacent well site and servicing more than one well site. The 2016 NSPS OOOOa required the reduction of methane and VOC emissions from new, reconstructed, or modified reciprocating compressors by replacing rod packing systems within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing. As an alternative, the 2016 NSPS OOOOa allowed owners or operators to collect the emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system.

In determining BSER for reciprocating compressors in 2016, the EPA determined that the previous determination for NSPS OOOO conducted in 2011/2012 still represented BSER in 2016. In the 2012 determination the EPA first concluded that the piston rod packing wear

produces fugitive emissions that cannot be captured and conveyed to a control device, and that an operational standard pursuant to section 111(h) of the CAA was appropriate. The EPA conducted analyses of the costs and emission reductions of the replacement of rod packing every 3 years or 26,000 hours of operation and determined that the costs per ton of emissions reduced were reasonable for the industry, with the exception of compressors at well sites. Based on the 2011 BSER analysis, requiring replacement of rod packing every 3 years or 26,000 hours of operation for well site reciprocating compressors was not considered cost effective (almost $57,000 per ton of VOC reduced).[275] No other more stringent control options were evaluated at that time.

For this review of the NSPS, the EPA focused on these control options which were previously assessed for the 2012 NSPS OOOO and the 2016 NSPS OOOOa. In addition, we evaluated an option that would require annual monitoring to determine if the rod packing needed to be replaced. This option is in contrast to the option where replacement is required on a fixed (*e.g.,* 3 year) schedule. For this review, BSER was evaluated for reciprocating compressors at gathering and boosting stations in the production segment (considered to be representative of emissions from reciprocating compressors at centralized production facilities), at natural gas processing plants, and at sites in the transmission and storage segment. In 2012 and in 2016, the EPA determined that the cost effectiveness of replacement of the rod packing based on the fixed 3-year (or 26,000 hours) schedule was unreasonable for reciprocating compressors located at the well site (discussed below). No new information has become available to change this determination. Therefore, we did not include reciprocating compressors located at well sites in our evaluation of regulatory options.

However, as discussed in section XI.L (Centralized Production Facilities) of this preamble, the EPA believes the definition of ''well site'' in NSPS OOOOa may cause confusion regarding whether reciprocating compressors located at centralized production facilities are also exempt from the standards. The EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. This proposal is necessary in the context of reciprocating compressors to distinguish between these compressors at centralized production facilities where the EPA has determined that the standard should apply, and compressors at standalone well sites where the EPA has determined that the standard should not apply. In our current analysis, described below, we consider the reciprocating compressor gathering and boosting segment emission factor as being representative of reciprocating compressor emissions located at centralized production facilities. As such, the EPA is proposing that reciprocating compressors located at centralized production facilities would be subject to the standards in NSPS OOOOb and the EG in subpart OOOOc, but reciprocating compressors at well sites (standalone well sites) would not.

As a result of the EPA's review of NSPS OOOOa, we are proposing that BSER is to replace the rod packing when, based on annual flow rate measurements, there are indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels. We are proposing that if annual flow rate monitoring indicates a flow rate for any individual cylinder as exceeding 2 scfm, an owner or operator would be required to replace the rod packing.

b. Description

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder.

As discussed previously, emissions from a reciprocating compressor occur when, over time, during operation of the compressor, the rings that form a seal around the piston rod that prevents gas from escaping become worn. This results in increasing emissions from the compression cylinder. Based on the 2021 GHGI,[276] the methane emissions from reciprocating compressors in 2019 represented 14 percent of the total methane emissions from natural gas systems in the Crude Oil and Natural Gas Industry sector. For segments where the GHGI included a breakdown of methane emissions for reciprocating compressors, the reported emissions were 309,500 metric tons for the gathering and boosting segment, 46,700 metric tons for the processing segment, 406,500 metric tons for the transmission segment, and 103,200 metric tons for the storage segment.

c. Affected Facility

For purposes of the NSPS, the reciprocating compressor affected facility is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under the proposed rule for the NSPS OOOOb. As discussed above, the EPA is proposing that the affected facility includes reciprocating compressors located at centralized production facilities and the affected facility exception for ''a well site, or an adjacent well site servicing more than one well site'' applies to standalone well sites and not centralized production facilities.

d. 2021 BSER Analysis

The methodology used for estimating emissions from reciprocating compressor rod packing is consistent with the methodology developed for the 2012 NSPS OOOO BSER analysis and then also used to support the 2016 NSPS OOOOa BSER. This approach uses volumetric methane emission factors referenced in the EPA/GRI study[277] as the basis, multiplied by the density of methane. These factors were per cylinder, so they were multiplied by the average number of cylinders per reciprocating compressor at each oil and gas industry segment, the pressurized factor (percentage of hours per year the compressor was pressurized), and 8,760 hours (number of hours in a year). Once the methane emissions were calculated, VOC emissions were calculated by multiplying the methane by ratios developed based on representative gas composition. The specific ratios that were used for this analysis were 0.278

[275] 2011 NSPS OOOO TSD. pg. 6–17.

[276] U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990–2019). Published in 2021. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019.

[277] EPA/GRI. (1996). *Methane Emissions from the Natural Gas Industry: Volume 8—Equipment Leaks.*

pounds VOC per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane for the transmission and storage segment. The resulting baseline emissions from reciprocating compressors were 12.3 tpy methane (3.4 tpy VOC) from gathering and boosting stations, 23.3 tpy methane (6.5 tpy VOC) from natural gas processing plants, 27.1 tpy methane (0.75 tpy VOC) from transmission stations, and 28.2 tpy methane (0.78 tpy VOC) from storage facilities.

Reducing emissions that result from the leaking of natural gas past the piston rod packing can be accomplished through several approaches including: (1) Specifying a frequency for the replacement of the compressor rod packing, (2) monitoring the emissions from the compressor and replacing the rod packing when the results exceed a specified threshold, (3) specifying a frequency for the replacement of the piston rod, (4) requiring the use of specific rod packing materials, and/or (5) capturing the leaking gas and routing it either to a process or a control device.

There was either insufficient information to establish BSER or it was determined that the option cannot be applied in all situations for approach options (3) through (5). These are discussed briefly below.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[278] Rods wear ''out-of-round'' or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. We assume that operators will choose, at their discretion, when to replace/realign or retrofit the rod as part of regular maintenance procedures and replace the rod when appropriate when the compressor is out of service for other maintenance such as rod packing replacement. Although replacing/realigning or retrofitting the rod has been identified as a potential methane and VOC emission reduction option for reciprocating compressors, there is insufficient information on its emission reduction potential and use throughout the industry. Therefore, we did not evaluate this option any further as BSER for this proposal.

Although specific analyses have not been conducted, there may be potential for reducing methane and VOC emissions by updating rod packing components made from newer materials, which can help improve the life and performance of the rod packing system. One option is to replace the bronze metallic rod packing rings with longer lasting carbon-impregnated Teflon rings. Compressor rods can also be coated with chrome or tungsten carbide to reduce wear and extend the life of the piston rod. Although changing the rod packing material has been identified as a potential methane and VOC emission reduction option for reciprocating compressors, there is insufficient information on its emission reduction potential and use throughout the industry. Therefore, we did not evaluate this option any further as BSER for this proposal.

The 2016 NSPS OOOOa includes the alternative to route the emissions from reciprocating compressors to a process. One estimate obtained by the EPA states that a gas recovery system can result in the elimination of over 99 percent of methane emissions that would otherwise occur from the venting of the emissions from the compressor rod packing. The emissions that would have been vented are combusted in the compressor engine to generate power. It was estimated that, if a facility is able to route rod packing vents to a VRU system, it is possible to recover approximately 95–100 percent of emissions. As a comparison, the EPA estimated that the 3-year/26,000-hour changeout results in between 55 and 80 percent emission reduction. Therefore, an option to achieve additional emission reductions could be to require routing the reciprocating compressor emissions to a process/through a closed vent system under negative pressure. Although this was a control option considered in the 2016 NSPS OOOOa (and included as an alternative), the EPA did not require routing to a process for all compressors because at that time there was insufficient information to require this as a control for all reciprocating compressors. The EPA received feedback that this option cannot be applied in every installation, and has not received any new information that indicates this has changed. Thus, this option was not considered further as a requirement but for this proposal, as with the 2016 NSPS OOOOa, it is considered to be an acceptable alternative to mitigate methane and VOC emissions where it is technically feasible to apply.

Similarly, another option evaluated as having the potential to achieve methane and VOC emission reductions was to require the collection of emissions in a closed vent system and routing them to a flare or other control device. If the gas is routed to a flare, approximately 95 percent of the methane and VOC would be reduced. The EPA has expressed historically and maintains that combustion is not believed to be a technically feasible control option for reciprocating compressors because, as detailed in the 2011 NSPS OOOO TSD, routing of emissions to a control device can cause positive back pressure on the packing, which can cause safety issues due to gas backing up in the distance piece area and engine crankcase in some designs. The EPA has not identified any new information to indicate that this has changed. Therefore, this option was not considered further as BSER for this proposal.

The remaining two control option approaches that were evaluated further for this proposal include: (1) Specifying a frequency for the replacement of the compressor rod packing (equivalent to the frequency used in the 2016 NSPS OOOOa BSER control level), and (2) monitoring the emissions from the compressor and replacing the rod packing when the results exceed a specified threshold. Both of these approaches would reduce the escape of natural gas from the piston rod. No wastes would be created (other than the worn packing that is being replaced) and no wastewater would be generated.

As noted previously, periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod, thereby limiting emissions occurring around the flexible rings that fit around the shaft by recreating a seal against leakage that may have been lost due to wear. The potential emission reductions for reciprocating compressors at gathering and boosting stations, processing plants, and transmission and storage facilities were calculated by comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing. As noted above, because the EPA concluded that the cost effectiveness of this option was extremely unreasonable for reciprocating compressors at well sites in previous BSER analyses (see the 2011 NSPS OOOO TSD, section 2.2; 80 FR 56620, September 18, 2015), and since no new information was identified that

[278] U.S. Environmental Protection Agency. *Lessons Learned from Natural Gas STAR Partners. Reducing Methane Emissions from Compressor Rod Packing Systems.* Natural Gas STAR Program. 2006.

would change this outcome as it relates to stand alone well sites, reductions and costs were not re-evaluated in this analysis for reciprocating compressors at production well sites.

The emissions after the replacement of the rod packing were calculated using the methodology used under previous NSPS actions (see NSPS OOOOb and EG TSD, section 7.1). The resulting emission reductions used for the analysis represented the emission reductions expected in the year the rod packing is replaced. It is expected that there would be an increase in the emissions (and decrease in the emission reductions) from a compressor where the rod packing was replaced the second and third years before the next replacement. As noted above, this assumed reduction was between 55 and 80 percent depending on the location of the compressor.

The costs of replacing rod packing were obtained from a Natural Gas STAR Lessons Learned document [279] and the dollars were converted to 2019 dollars. The estimated cost to replace the packing rings in 2019 dollars was estimated to be $1,920 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance, and therefore no additional travel costs would be incurred for implementing a rod packing replacement program. Since the assumed number of cylinders differs for reciprocating compressors at different segments, this means the capital costs also vary. These estimated capital costs are $6,350 at gathering and boosting and transmission stations, $4,800 at processing plants, and $8,650 at storage stations.

The 26,000-hour replacement frequency used for the cost impacts in the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD was determined using a weighted average of the annual percentage of time that reciprocating compressors are pressurized. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3.8 years for gathering and boosting compressors, 3.3 years for processing compressors, 3.8 years for transmission compressors, and 4.4 years for storage compressors. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3093, 0.3498, 0.3093, and 0.2695 for the gathering and boosting part of production, processing, transmission, and storage segments, respectively.

The capital costs were calculated using the average rod packing cost noted above and the average number of cylinders per compressor (which differs depending on sector segment). The annual capital costs were calculated using the capital costs and the capital recovery factors. The estimated annual costs ranged from $1,700 at processing plants to just over $2,300 at storage facilities. Note that these estimated costs represent the costs, and associated emission reductions, that would occur in the year when the rod packing was changed. There would be no costs for the other two years in the three-year cycle. The costs presented for gathering and boosting segment reciprocating compressors represent the estimated costs assumed for reciprocating compressors located at centralized production facilities.

There are monetary savings associated with the amount of natural gas saved with reciprocating compressor rod packing replacement. Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement were estimated using a natural gas price of $3.13 per Mcf. Estimated savings were only applied for gathering and boosting stations and processing plants, as it is assumed the owners of the compressor station do not own the natural gas that is compressed at the station.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness of replacement of the reciprocating rod packing within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing, is approximately $290 per ton of methane reduced for gathering and boosting ($100 per ton if gas savings are considered), $90 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $90 per ton of methane reduced for the transmission segment, and $110 per ton of methane reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of replacement of the reciprocating rod packing within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing, is approximately $140 per ton of methane reduced for gathering and boosting ($50 per ton if gas savings are considered), $45 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $45 per ton of methane reduced for the transmission segment, and $50 per ton of methane reduced for the storage segment.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the VOC cost effectiveness of replacement of the reciprocating rod packing within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing, is approximately $1,030 per ton of VOC reduced for gathering and boosting ($380 per ton if gas savings are considered), $330 per ton of VOC reduced for the processing segment (net savings if gas savings are considered), $3,260 per ton of VOC reduced for the transmission segment, and $3,860 per ton of VOC reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of replacement of the reciprocating rod packing within 26,000 hours or 36 months of operation, regardless of the condition of the rod packing, is approximately $520 per ton of VOC reduced for gathering and boosting ($190 per ton if gas savings are considered), $160 per ton of VOC reduced for the processing segment (net savings if gas savings are considered), $1,630 per ton of VOC reduced for the transmission segment, and $1,930 per ton of VOC reduced for the storage segment.

As an alternative to replacing the rod packing on a fixed schedule, another option is to replace the rod packing when, based on measurements, there are indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels. This is an approach required by the California Greenhouse Gas Emission Regulation and in Canada. The California Greenhous Gas Emission Regulation requires that the rod packing/seal be tested during periodic inspections and, if the rod packing/seal leak concentration exceeds the specified threshold of 2 scfm/cylinder, repairs must be made within 30 days.[280] Similarly, certain Canadian jurisdictions require periodic monitoring measurements of rod packing vent

[279] EPA (2006). *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems.* Natural Gas STAR. Environmental Protection Agency.

[280] State of California Air Resources Board (CARB). ''Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.'' Oil and Gas Final Regulation Order (*ca.gov*).

volumes (typically annually) for existing reciprocating compressors. Where specified vent volumes are exceeded, the rules require corrective action be taken to reduce the flow rate to below or equal to a specified limit, as demonstrated by a remeasurement. Vent volume thresholds specified that would result in the need for corrective action vary from 0.49 to 0.81 scfm/cylinder.[281]

This approach is similar to an approach identified in the Natural Gas STAR Program referred to as ''Economic Packing and Piston Rod Replacement.'' [282] Under this approach, facilities use specific financial objectives and monitoring data to determine emission levels at which it is cost effective to replace rings and rods. Benefits of calculating and utilizing this ''economic replacement threshold'' include methane and VOC emission reductions and natural gas cost savings. Using this approach, one Natural Gas STAR partner reportedly achieved savings of over $233,000 annually at 2006 gas prices. An economic replacement threshold approach can also result in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term savings. The EPA is not proposing to establish a financial objective or economic replacement threshold in this proposal, but the costs and emission reductions of replacing rod packing based on monitoring from this program were considered in the analysis discussed below.

The elements of such a program include establishing a frequency of monitoring, identifying a threshold where action is required to reduce emissions, and specifying the action for reducing emissions. The option defined by the EPA and evaluated below is for annual monitoring and requiring the replacement of the rod packing if the measured flow rate for any individual cylinder exceeds 2 scfm. This threshold is consistent with California's regulation. However, this option differs from the California regulation in that it would require a complete replacement of the rod packing if this threshold is exceeded, where California allows repair sufficient to reduce the flow rate back below 2 scfm. The 2 scfm flow rate threshold was established based on manufacturer guidelines indicating that a flow rate of 2 scfm or greater was considered indicative of rod packing failure.[283]

We estimated the emission reductions from requiring annual flow rate monitoring and repair/replacement of packing when the measured flow rate exceeds 2 scfm total gas during pressurized operation. Based on California's background regulatory documentation, information provided to the State indicated that the average leak rate for those compressors emitting more than 2 scfm was about 3 scfm during pressurized operation, and less than 2 scfm during pressurized idle and unpressurized states. Therefore, we assumed that the leak rate for compressors emitting more than 2 scfm was about 3 scfm during pressurized operation. As indicated above for the fixed schedule rod packing replacement option, based on the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD, the average emissions from a newly installed rod packing are assumed to be 11.5 scfh per cylinder.[284] Using a ratio of 0.829 methane: Total natural gas ratio, 3 scfm total gas is approximately 2.49 scfm (149.2 scfh) methane. This compressor emission rate, which was used for all industry segments, was converted to an annual mass emission rate by applying segment-specific pressurized factors, then converted to a mass basis.

The estimated percent reduction in methane emissions that would be achievable from reducing 149.2 scfh methane/cylinder to 11.5 scfh methane/cylinder (average emissions from a newly installed rod packing/cylinder) is 92 percent. We applied this percent reduction in methane emissions and estimated reciprocating compressor methane and VOC emission reductions that would be achieved from repairing/replacing rod packing based on the annual flow rate monitoring option. The calculations assume that all cylinders are emitting at 3 scfm, and that the rod packings for all compressor cylinders are replaced. This represents the emission reductions expected for the year in which the rod packings are replaced. Emissions would be expected to increase (and emission reductions decrease) in subsequent years until the next time the annual measurements require that the rod packing be replaced.

The capital and annual costs of replacing the rod packings are the same as presented above for the fixed interval rod packing replacement option. In addition, this option would include the costs associated with the annual flow measurements. The estimated costs of this monitoring are based on the costs for annual flow rate monitoring under GHGRP subpart W for similar flow rate annual measurement requirements ($597). The capital costs associated with replacing compressor rod packing would only occur in the year when packing is required to be replaced. The monitoring costs would be incurred every year.

Additionally, the cost estimates assume that the packing of all compressor cylinders would need to be replaced (which is unlikely to be the case in many instances) and are therefore conservative estimates. Support information for the California rule cites data indicating that approximately 14 percent of compressors measurements indicated a leak rate of over 2 scfm per cylinder. Based on an average of 3.45 cylinders/compressor, California assumed that the packing for 2 cylinders/compressor would need to be replaced to come into compliance with the 2 scfm standard (57.9 percent).[285]

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness of the annual monitoring option is approximately $230 per ton of methane reduced for gathering and boosting ($40 per ton if gas savings are considered), $110 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $100 per ton of methane reduced for the transmission segment, and $110 per ton of methane reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of replacement of the reciprocating rod packing based on the annual monitoring approach is approximately $110 per ton of methane reduced for gathering and boosting ($20 per ton if gas savings are considered), $50 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $50 per ton of methane reduced for the transmission

[281] Canadian Federal standards: *http://gazette.gc.ca/rp-pr/p2/2018/2018-04-26-x1/pdf/g2-152x1.pdf;* Discussion Draft Regulation 26.11.41 (*maryland.gov*); *MAP-Technical-Report-December-19-2019-FINAL.pdf* (*nm.gov*).

[282] U.S. Environmental Protection Agency. *Lessons Learned from Natural Gas STAR Partners. Reducing Methane Emissions from Compressor Rod Packing Systems.* Natural Gas STAR Program. 2006.

[283] State of California. *Air Resources Board Public Hearing to Consider the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.* Staff Report: Initial Statement of Reasons. pgs. 96–97.

[284] 2011 TSD, pg. 6–13.

[285] Based on Appendix B. Economic Analysis. State of California. Air Resources Board. *Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.* pg. B–28. Notice Package for Oil and Gas Reg (*ca.gov*); State of California. *Air Resources Public Hearing to Consider the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.* Staff Report: Initial Statement of Reasons. Date of Release: May 31, 2016. pg. 99.

segment, and $60 per ton of methane reduced for the storage segment.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the VOC cost effectiveness of the annual monitoring option is approximately $810 per ton of VOC reduced for gathering and boosting ($160 per ton if gas savings are considered), $380 per ton of VOC reduced for the processing segment (net savings if gas savings are considered), $3,700 per ton of VOC reduced for the transmission segment, and $4,100 per ton of VOC reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of replacement of the reciprocating rod packing based on the annual monitoring approach is approximately $410 per ton of VOC reduced for gathering and boosting ($80 per ton if gas savings are considered), $190 per ton of VOC reduced for the processing segment (net savings if gas savings are considered), $1,850 per ton of VOC reduced for the transmission segment, and $2,040 per ton of VOC reduced for the storage segment.

We also assessed the incremental cost effectiveness of the annual monitoring option compared to the fixed 3-year/26,000 replacement schedule. Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the incremental cost effectiveness (without natural gas savings) from the fixed replacement option to the annual monitoring option for methane is approximately $130 per ton for gathering and boosting stations, $210 per ton for processing plants, $180 per ton for transmission stations, and $140 per ton for storage facilities. For VOC, the incremental cost effectiveness is approximately $480 per ton for gathering and boosting stations, $750 per ton for processing plants, $6,600 per ton for transmission stations, and $5,150 per ton for storage facilities.

The cost effectiveness of both options (fixed schedule and annual monitoring) are reasonable for methane and VOC using either the single pollutant or multipollutant approach. The incremental cost effectiveness in going from the fixed schedule option to the annual monitoring option is reasonable for all scenarios, with the exception of VOC for transmission stations. Therefore, based on the consideration of the costs in relation to the emission reductions, the EPA finds that the annual monitoring option is the most reasonable option.

Further, as discussed above, California requires reciprocating compressor annual rod packing flow rate monitoring and repair and or replacement of the packing where flow rate monitoring indicates a measurement that exceeds 2 scfm. This further supports the reasonableness of a monitoring program.

Neither the fixed schedule rod packing replacement option nor the rod packing replacement based on annual monitoring option would result in secondary emissions impacts as both options would reduce the escape of natural gas from the piston rod. No wastes would be created (other than the worn packing that is being replaced) and no wastewater would be generated. An advantage related to the replacement of rod packing for reciprocating compressors based on annual rod packing monitoring is that it would only require replacement of the rod packing where monitoring of the rod packing indicates wear and increasing flow rate/emissions to unacceptable levels. This optimizes the output of capital expenditures to focus on emissions control where an increased emissions potential is identified.

In light of the above we determined that annual rod pack flow rate monitoring and replacement of the packing where flow rate monitoring indicates a measurement that exceeds 2 scfm represents BSER for NSPS OOOOb for this proposal for all segments including reciprocating compressors located at centralized productions facilities (with the exception of compressors at stand-alone well sites). As in the 2016 NSPS OOOOa, the EPA is proposing to allow the collection and routing of emissions to a process as an alternative standard because that option would achieve emission reductions equivalent to, or greater than, the proposed standard for NSPS OOOOb.

The affected facility based on EPA's review would continue to be each reciprocating compressor not located at a well site, or an adjacent well site and servicing more than one well site. As discussed above, the EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. Thus, the EPA is proposing that reciprocating compressors located at centralized production facilities would be subject to the standards in NSPS in OOOOb, but reciprocating compressors at well sites (standalone well sites) would not.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing reciprocating compressors (designated facilities) in all segments in the Crude Oil and Natural Gas source category covered by the proposed NSPS OOOOb and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities that essentially mirrors the proposed NSPS OOOOb.

First, based on the same criteria and reasoning as explained above, the EPA is proposing to define the designated facility in the context of existing reciprocating compressors as those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should alter this definition as applied to existing sources. Next, the EPA finds that the control measures evaluated for new sources for NSPS OOOOb are appropriate for consideration for existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission reduction, for reciprocating compressors that could be used for existing sources but not for new sources. Next, the methane emission reductions expected to be achieved via application of the control measures identified above to new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

The EPA has not identified any costs associated with applying these controls at existing sources, such as retrofit costs, that would apply any differently than, or in addition to, those costs assessed above regarding application of the identified controls to new sources. The cost effectiveness values for the

proposed presumptive standard of replacement of the rod packing based on an annual monitoring threshold is approximately $230 per ton of methane reduced ($40 per ton if gas savings are considered) for the gathering and boosting segment (including reciprocating compressors located at centralized tank facilities), $110 per ton of methane reduced for the processing segment (net savings if gas savings are considered), $100 per ton of methane reduced for the transmission segment, and $110 per ton of methane reduced for the storage segment.

In summary, the EPA did not identify any factors specific to existing sources, as opposed to new sources, that would alter the analysis above for the proposed NSPS OOOOb as applied to the designated pollutant (methane) and the designated facilities (reciprocating compressors). As a result, the proposed presumptive standard for existing reciprocating compressors is as follows.

For reciprocating compressors in the gathering and boosting segment (including reciprocating compressors located at centralized tank facilities), processing, and transmission and storage segments, the presumptive standard is replacement of the rod packing based on an annual monitoring threshold. Specifically, the presumptive standard would require an owner or operator of a reciprocating compressor designated facility to monitor the rod packing flow rate annually. When the measured leak rate exceeds 2 scfm (in pressurized mode), the standard would require replacement of the rod packing. As an alternative, the presumptive standard would be routing rod packing emissions to a process via a closed vent system under negative pressure.

F. Proposed Standards for Centrifugal Compressors

1. NSPS OOOOb

a. Background

The 2012 NSPS OOOO and the 2016 NSPS OOOOa applied to each wet seal compressor not located at a well site, or an adjacent well site and servicing more than one well site. The 2016 NSPS OOOOa required methane and VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95.0 percent. Compliance with this requirement allowed routing of emission from the wet seal fluid degassing system to a control device or to a process. Dry seal compressors were not subject to requirements under the 2016 NSPS OOOOa.

In determining BSER for wet seal compressors in 2016, the EPA determined that the previous determination for NSPS OOOO conducted in 2011/2012 still represented BSER for the control of VOC in 2016. In addition, the EPA determined that analogous control of methane represented BSER. In the 2012 determinations, the EPA conducted analyses of the cost and emission reductions of (1) requiring the conversion of a wet seal system to a dry seal system, and (2) routing to a control device or process. The 2011 NSPS OOOO rule (76 FR 52738, 52755, August 23, 2011) proposed an equipment standard that would have required the use of dry seals to limit the VOC emissions from new centrifugal compressors. At that time, the EPA solicited comments on the emission reduction potential, cost, and any technical limitations for the option of routing the gas back to a low-pressure fuel stream to be combusted as fuel gas. In addition, in 2011 (76 FR 52738), the EPA solicited comments on whether there are situations or applications where a wet seal is the only option, because a dry seal system is infeasible or otherwise inappropriate. The EPA received information indicating that the integration of a centrifugal compressor into an operation may require a certain compressor size or design that is not available in a dry seal model, and in the case of capture of emissions with routing to a process, there may not be down-stream equipment capable of handling a low-pressure fuel source. In the final 2012 NSPS OOOO rule, the EPA made the determination that the replacement of wet seals with dry seals and routing to a process was not technically feasible or practical for some centrifugal compressors, and also that the costs per ton of emissions reduced were reasonable for routing emissions to a control device or process. No other more stringent control options were evaluated at that time. During the development of the 2016 NSPS OOOOa rule, the EPA reviewed available information on control options for wet seal compressors and did not identify any new information to indicate that this has changed.

For this review, the EPA also focused on these control options. BSER was evaluated for wet-seal centrifugal compressors at gathering and boosting stations (considered to be representative of emissions from centrifugal compressors at centralized production facilities) in the production segment, at natural gas processing plants, and at sites in the transmission and storage segment. During the development of the 2012 NSPS OOOO and 2016 NSPS OOOOa rulemakings, our data indicated that there were no centrifugal compressors located at well sites. Since the 2012 NSPS OOOO and 2016 NSPS OOOOa rulemakings, we have not received information that would change our understanding that there are no centrifugal compressors in use at well sites.

However, as discussed in section XI.L (Centralized Production Facilities) of this preamble, the EPA believes the definition of ''well site'' in NSPS OOOOa may cause confusion regarding whether centrifugal compressors located at centralized production facilities are also exempt from the standards. The EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. This proposal is necessary in the context of centrifugal compressors to distinguish between these compressors at centralized production facilities where the EPA has determined that the standard should apply, and compressors at standalone well sites where the EPA has determined that the standard should not apply. In our current analysis, described below, we consider the centrifugal compressor gathering and boosting segment emission factor as being representative of centrifugal compressor emissions located at centralized production facilities. As such, the EPA is proposing that centrifugal compressors located at centralized production facilities would be subject to the standards in NSPS OOOOb and the EG in subpart OOOOc, but centrifugal compressors at well sites (standalone well sites) would not.

In addition to the requirement to reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent, the 2016 NSPS OOOOa requires compressor components to be monitored as fugitive emissions components and leaks found are to be repaired under the fugitive emissions monitoring requirements of 40 CFR 60.5397a. The monitoring frequency depends on source (*i.e.,* well sites, compressor stations) and sector segment. These fugitive emissions components were not considered part of the centrifugal compressor affected facility.

Based on the EPA's review of NSPS OOOOa, we are proposing that BSER continues to be that methane and VOC

emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

b. Description

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Some centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and adsorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process. Off gassing of entrained natural gas from wet seal centrifugal compressors is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process.

Some centrifugal compressors utilize dry seal systems. Dry seal systems minimize leakage by using the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed natural gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This natural gas is pumped between the grooves in the rotating and stationary rings. The opposing force of high-pressure natural gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little natural gas can leak. While the compressor is operating, the rings are not in contact with each other and, therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case. Historically, the EPA has considered dry seal centrifugal compressors to be inherently low-emitting and has never required control of emissions from dry seal compressors. The EPA has received feedback,[286] however, that there are some wet seal compressor system designs that are also low emitting when compared to dry seal compressors and is soliciting comment on lower emitting wet seal compressor system designs and dry seal compressor emissions in this proposed action.

The 2021 U.S. GHGI estimates over 166,700 metric tpy of methane emissions in 2019 from compressors from natural gas systems. For the natural gas processing and transmission segments, wet seal compressor methane emissions are estimated to be about 78,700 metric tons and dry seal compressor methane estimated emissions are estimated to be about 88,000 metric tons.[287] The wet seal and dry seal compressor methane emission estimates reflect the increasing prevalence of the use of dry seals over wet seals and emissions control requirements that require the control of emissions from wet seal compressors. The methane emissions from centrifugal compressors represent 3 percent of the total methane emissions from natural gas systems in the Oil and Natural Gas Industry sector.

c. Affected Facility

For purposes of the NSPS, the centrifugal compressor affected facility is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under the proposed rule for NSPS OOOOb. As discussed above, the EPA is proposing that the affected facility includes centrifugal compressors located at centralized production facilities and the affected facility exception for ''a well site, or an adjacent well site servicing more than one well site'' applies to standalone well sites and not centralized production facilities.

d. 2021 BSER Analysis

The methodology we used for estimating emissions from compressors is consistent with the methodology developed for the 2012 NSPS OOOO BSER analysis, which was also used to support the 2016 NSPS OOOOa BSER.[288] The wet-seal centrifugal compressor methane uncontrolled emission factors are based on the volumetric emission factors used for the GHGI, which were converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. The VOC emissions were calculated using the ratio of 0.278 pounds VOC per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane for the transmission and storage segment. The resulting baseline uncontrolled emissions per centrifugal compressor are 157 tpy methane (43.5 tpy VOC) from wet-seal compressors at gathering and boosting sites, 211 tpy methane (58.7 tpy VOC) from wet-seal compressors at natural gas processing plants, 157 tpy methane (4.3 tpy VOC) from wet-seal compressors at transmission compressor stations, and 117 (3.24 tpy VOC) from wet-seal compressors at storage facilities. Since the emission factors for dry seal compressors are approximately lower than wet seal compressors,[289] the EPA considered requiring dry seals as a replacement to wet seals as a control option in 2011. The EPA proposed dry seals as a replacement to wet seals to control VOC emissions at that time. Based on comments received on the proposal that dry seal compressors were not feasible in all instances based on costs and technical reasons, the EPA did not finalize the proposal that dry seal compressors represented BSER. Instead, the EPA separately evaluated the control options for wet seal compressors (77 FR 49499–49500, 49523, August 16, 2012). In the 2015 NSPS OOOOa proposed rule, the EPA maintained that available information since the 2012 NSPS OOOO rule continued to show that dry seal compressors cannot be use in all circumstances. The EPA has not identified any new information since that time that indicates that dry seal compressors as a replacement for wet seal compressors is technically feasible in all circumstances. Thus, we did not evaluate the replacement of a wet seal system with a dry seal system as BSER for controlling emissions from wet seal systems for the NSPS OOOOb proposal.

In addition to soliciting comment and information on lower-emitting wet seal compressor designs (that emit less than dry seal compressors), the EPA is soliciting information on dry seal compressor emissions. Feedback received (noted above) on lower emitting wet seal compressor designs included concern that lower emitting wet seal systems were being replaced by higher emitting (but still low emitting) dry seal systems because they were not subject to the NSPS. Given that the trend has been that wet seal compressor systems are increasingly being replaced by dry seal compressor systems, the EPA solicits comments on dry seal compressor emissions and whether/and

[286] Conference Call. Prepared by Tora Consulting. December 19, 2018.

[287] U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990–2019). Published in 2021. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019.

[288] 2011 NSPS OOOO TSD, section 6.2.2; 2016 NSPS OOOOa TSD, section 7.2.2.

[289] 2011 NSPS OOOO TSD, Table 6–2, pg. 6–4; 2016 NSPS OOOOa TSD, Table 7–2, pg. 104.

to what degree operational or malfunctioning conditions (*e.g.,* low seal gas pressure, contamination of the seal gas, lack of supply of separation gas, mechanical failure) have the potential to impact methane and VOC emissions. The EPA also solicits comment on whether owners and operators implement standard operating procedures to identify and correct operational or malfunction conditions that have the potential to increase emissions from dry seal systems. Finally, the EPA solicits comments on whether we should consider evaluating BSER and developing NSPS standards for dry seal compressors.

The control options to reduce emissions from centrifugal compressors evaluated include control techniques that reduce emissions from leaking of natural gas from wet seal compressors by capturing leaking gas and route it either to (1) a control device (combustion device), or (2) to the process. We evaluated the costs and impacts of both of these options.

Combustion devices are commonly used in the Crude Oil and Natural Gas Industry to combust methane and VOC emission streams. Combustors are used to control VOC and methane emissions in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value and inert species content.[290] A combustion device generally achieves 95 percent reduction of methane and VOC when operated according to the manufacturer instructions. For this analysis, we assumed that the entrained natural gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves a 95 percent reduction of methane and VOC emissions. This option was determined to be BSER under the 2011 NSPS OOOO (77 FR 49490, August 16, 2012) and 2016 NSPS OOOOa rules. The combustion of the recovered gas creates secondary emissions of hydrocarbons (NO_X, CO_2, and CO emissions). Routing the captured gas from the centrifugal compressor wet seal degassing system to a combustion device has associated capital and operating costs.

The capital and annual costs for the installation of a combustion device (an enclosed flare for the analysis) were calculated using the methodology in the EPA Control Cost Manual.[291] The capital costs of a flare and the equipment (closed vent system) necessary to route emissions to the flare are based on costs from the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD. These costs were updated to 2019 dollars. The updated capital costs of $80,930 were annualized at 7 percent based on an equipment life of 10 years. The total annualized capital costs were estimated to be $11,520. The annual operating costs are also based on the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD. These costs were updated to 2019 dollars. The 2019 annual operating costs were estimated to be $117,160. The combined annualized capital and operating costs per compressor per year is an estimated $128,680. There is no cost savings estimated for this option because the recovered natural gas is combusted. The costs presented for gathering and boosting segment centrifugal compressors represent the estimated costs assumed for centrifugal compressors located at centralized production facilities.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness of routing emissions from a wet seal system to a new flare for methane emissions is $870 per ton of methane reduced for the transmission segment and gathering and boosting, $640 per ton of methane reduced for the processing segment, and $1,160 per ton of methane reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of routing emissions from a wet seal system to a new flare for methane emissions is $430 per ton of methane reduced for the transmission segment and gathering and boosting, $320 per ton of methane reduced for the processing segment, and $580 per ton of methane reduced for the storage segment.

Using the single-pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness of routing emissions from a wet seal system to a new flare for VOC emissions is $3,100 per ton of VOC reduced for gathering and boosting, $2,300 per ton of VOC reduced for the processing segment, $31,200 per ton of VOC reduced for the transmission segment, and $41,800 per ton of VOC reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness of routing emissions from a wet seal system to a new flare for VOC emissions is $1,600 per ton of VOC reduced for gathering and boosting, $1,200 per ton of VOC reduced for the processing segment, $15,600 per ton of VOC reduced for the transmission segment, and $20,900 per ton of VOC reduced for the storage segment.

In addition to an owner or operator having the option to capture emissions and routing to a new combustion control device, a less costly option that may be available could be for owners and operators to capture and route emissions to a combustion control device installed for another source (*e.g.,* a control device that is already on site to control emissions from another emissions source). The costs, which are provided in the NSPS OOOOb and EG TSD for this rulemaking, would be for the ductwork to capture the emissions and route them to the control device. The analysis assumes that the combustion control device on site achieves a 95 percent reduction in emissions of methane and VOC.

Another option for reducing methane and VOC emissions from the compressor wet seal fluid degassing system is to route the captured emissions back to the compressor suction or fuel system, or other beneficial use (referred to collectively as routing to a process). Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit (*e.g.,* compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Emissions that are routed to a process are assumed to result in the same or greater emission reductions as would have been achieved had the emissions been routed through a closed vent system to a combustion device.[292] For purposes of this analysis, we assumed that routing methane and VOC emissions from a wet seal fluid degassing system to a process reduces VOC emissions greater than or equal to a combustion device (*i.e.,* greater than or equal to 95 percent). There are no secondary impacts with the option to control emissions from centrifugal wet seals by capturing gas and routing to the process.

[290] U.S. Environmental Protection Agency. AP 42, Fifth Edition, Volume I, *Chapter 13.5 Industrial Flares.* Office of Air Quality Planning & Standards. 1991.

[291] U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B–02–001). Research Triangle Park, NC.

[292] U.S. Environmental Protection Agency. Control Techniques Guidelines for the Oil and Natural Gas Industry. Office of Air Quality Planning and Standards, Sector Policies and Programs Division. October 2016. EPA–453/B–16–001. (2016 CTG). pgs. 5–19 to 5–20.

The capital cost of a system to route the seal oil degassing system to a process is estimated to be $26,210 ($2,019),[293] The estimated costs include an intermediate pressure degassing drum, new piping, gas demister/filter, and a pressure regulator for the fuel line. The annual costs were estimated to be $2,880 (without savings) assuming a 15-year equipment life at 7 percent interest. Because the natural gas is not lost or combusted, the value of the natural gas represents a savings to owners and operators in the production (gathering and boosting) and processing segments. Savings were estimated using a natural gas price of $3.13 per Mcf, which resulted in annual savings of $27,000 per year at gathering and boosting stations and $36,400 per year at processing plants. The annual cost savings are much greater than the annual costs, which results in an overall savings when they are considered.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for methane emissions is approximately $19 per ton of methane reduced for the transmission segment and gathering and boosting, $14 per ton of methane reduced for the processing segment, and $26 per ton of methane reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for methane emissions is approximately $10 per ton of methane reduced for the transmission segment and gathering and boosting, $7 per ton of methane reduced for the processing segment, and $13 per ton of methane reduced for the storage segment. As noted above, there is an overall net savings if the value of the natural gas recovered is considered.

Using the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, the cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for VOC emissions is approximately $70 per ton of VOC reduced for gathering and boosting, $50 per ton of VOC reduced for the processing segment, $700 per ton of VOC reduced for the transmission segment, and $940 per ton of VOC reduced for the storage segment. Using the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for VOC emissions is approximately $35 per ton of VOC reduced for gathering and boosting, $26 per ton of VOC reduced for the processing segment, $350 per ton of VOC reduced for the transmission segment, and $470 per ton of VOC reduced for the storage segment. As noted above, there is an overall net savings if the value of the natural gas recovered is considered.

The cost effectiveness of both options (routing emissions to a combustion device or to a process) are reasonable for methane for all of the evaluated segments, using both the single pollutant and multipollutant approaches. The cost effectiveness of routing emissions to a process are also reasonable for VOC for all of the evaluated segments, using both the single pollutant and multipollutant approaches. For routing emissions to a combustion device, the cost effectiveness is reasonable for the gathering and boosting and processing segments using the single pollutant and multipollutant approaches. Based on the consideration of the costs in relation to the emission reductions of both methane and VOC, the EPA finds that requiring emissions to be reduced from each centrifugal compressor using a wet seal by at least 95 percent (which can be achieved by either option) continues to be reasonable in the gathering and boosting (considered to be representative of emissions/costs from centrifugal compressors at centralized production facilities). processing, transmission and storage segments.

The 2012 NSPS OOOO and the 2016 NSPS OOOOa require emissions be reduced from each centrifugal compressor wet seal fluid degassing system by at least 95.0 percent by routing emissions to a control device or to a process. States have generally adopted/incorporated this NSPS level of control (or a level of control that is substantially similar) in their State regulations for the control of emissions from centrifugal compressor sources using wet seals. Owners and operators have successfully met this standard for almost a decade. These facts further demonstrate the reasonableness of this level of control. In the discussion above, we reviewed two options to reduce emissions from wet seal compressors that are both current regulatory options under the 2016 NSPS OOOOa: (1) Capturing leaking gas and route to a combustion device (flare), or (2) capturing leaking gas and route to the process. Under the 2016 NSPS OOOOa, the level of control determined based on BSER was that methane and VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater. The EPA has not identified any other control options or any other Federal, State, or local requirements that would achieve a greater reduction in methane and VOC emissions from centrifugal compressor wet seal systems. Although capturing leaking gas and routing to the process has the advantage of both reducing emissions by at least 95 percent or greater and capturing the natural gas (resulting in a natural gas savings), the EPA has received feedback in the development of the 2012 NSPS OOOO rule that this option may not be a viable option in situations where there may not be down-stream equipment capable of handling a low-pressure fuel source. During the development of the 2016 NSPS OOOOa rule, the EPA reaffirmed that information since the development of the 2012 NSPS OOOO rule continues to show that capturing leaking gas and routing to the process cannot be used in all circumstances. No new information has been identified since the development of the 2016 NSPS OOOOa rule to indicate that capturing leaking gas and routing to the process can be achieved in all circumstances (80 FR 56619, September 18, 2015). Thus, by establishing a 95 percent methane and VOC emissions control level as BSER, an owner or operator has the option of routing emissions to a process where it is a viable option, or to a combustion device where routing to a process is not a viable option. If an owner or operator chooses to route to a process to meet the 95 percent level of control, there are no secondary impacts. If an owner or operator chooses to route to a combustion device to meet the 95 percent level of control, the combustion of the recovered gas creates secondary emissions of hydrocarbons (NO_X, CO_2, and CO emissions).

The costs, emission reductions, and cost effectiveness values were presented above for collecting the wet seal compressor emissions and routing them to both a combustion device and to a process to achieve at least a 95 percent control. The EPA considers the cost effectiveness of both of these control options reasonable across all segments evaluated (*i.e.,* the gathering and boosting portion of production, processing, transmission, storage) for the reduction of methane emissions under the single pollutant approach and multipollutant approach. As discussed

[293] 2011 NSPS OOOO TSD, pg. 114; 2016 CTG, pg. 5–20.

above, in our current analysis, we consider the centrifugal compressor gathering and boosting segment emission factor as being representative of centrifugal compressor emissions located at centralized production facilities. Thus, the cost analysis performed for the gathering and boosting segment represents the estimated costs of evaluated options for centrifugal compressors with wet seals located at centralized storage facilities.

In light of the above, we determined that reducing methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater continues to represent BSER for NSPS OOOOb for this proposal. The affected facility based on EPA's review would continue be each wet seal compressor not located at a well site, or an adjacent well site and servicing more than one well site. As discussed above, the EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. Thus, the EPA is proposing that centrifugal compressors located at centralized production facilities would be subject to the standards in the NSPS in OOOOb, but centrifugal compressors at well sites (standalone well sites) would not.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing centrifugal compressors using wet seals (not located at a well site, or an adjacent well site and servicing more than one well site) (designated facilities) in all segments in the Crude Oil and Natural Gas source category covered by the proposed NSPS OOOOb and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities that essentially mirrors the proposed NSPS OOOOb.

First, based on the same criteria and reasoning as explained above, the EPA is proposing to define the designated facility in the context of existing centrifugal compressors using wet seals (not located at a well site, or an adjacent well site and servicing more than one well site) as those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should alter this definition as applied to existing sources. Next, the EPA finds that the control measures evaluated for new sources for NSPS OOOOb are appropriate for consideration for existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission reduction, for centrifugal compressors that could be used for existing sources but not for new sources. Next, the methane emission reductions expected to be achieved via application of the control measures identified above to new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

The EPA has not identified any costs associated with applying these controls at existing sources, such as retrofit costs, that would apply any differently than, or in addition to, those costs assessed above regarding application of the identified controls to new sources. The cost effectiveness values for the proposed presumptive standard of reducing methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater are based on the cost effectiveness of routing emissions from a wet seal system to a flare or to a process. The cost effectiveness of routing emissions from a wet seal system to a new flare for methane emissions is $870 per ton of methane reduced for the transmission segment and gathering and boosting, $640 per ton of methane reduced for the processing segment, and $1,160 per ton of methane reduced for the storage segment. The cost effectiveness (without natural gas savings) of routing emissions from a wet seal system to a process for methane emissions is approximately $19 per ton of methane reduced for the transmission segment and gathering and boosting, $14 per ton of methane reduced for the processing segment, and $26 per ton of methane reduced for the storage segment.

In summary, the EPA did not identify any factors specific to existing sources, as opposed to new sources, that would alter the analysis above for the proposed NSPS OOOOb as applied to the designated pollutant (methane) and the designated facilities (centrifugal compressors using wet seals). As a result, the proposed presumptive standard for existing centrifugal compressors using wet seals is as follows.

For centrifugal compressors using wet seals in the gathering and boosting segment (including centrifugal compressors using wet seals located at centralized tank facilities), processing, and transmission and storage segments, the presumptive standard is to reduce methane emissions by at least 95 percent. An owner or operator can meet this presumptive standard by routing methane emissions to a control device or process that reduces emissions by at least 95 percent. As discussed previously, the EPA is proposing a new definition for a ''centralized production facility''. The EPA is proposing to define centralized production facilities separately from well sites because the number and size of equipment, particularly reciprocating and centrifugal compressors, is larger than standalone well sites which would not be included in the proposed definition of ''centralized production facilities''. Thus, the EPA is proposing that centrifugal compressors located at centralized production facilities would be subject to the standards in the EG in OOOOc, but centrifugal compressors at well sites (standalone well sites) would not.

G. Proposed Standards for Pneumatic Pumps

1. NSPS OOOOb

a. Background

In the 2016 NSPS OOOOa, the EPA established GHG (in the form of limitations on methane emissions) and VOC standards for natural gas-driven diaphragm pneumatic pumps located at well sites. This standard required that natural gas emissions be reduced by 95.0 percent by routing to an existing control device if: (1) A control device was onsite, (2) the control device could achieve a 95.0 percent reduction, and (3) it was technically feasible to route the emissions to the control device. The standard did not require the installation of a control device solely for the purpose of complying with the 95.0 percent reduction for the emissions from pneumatic pumps. It also allowed

the option of routing emissions to a process. At natural gas processing plants, the EPA established a standard that required a natural gas emission rate of zero (*i.e.,* that prohibited methane and VOC emissions from pneumatic pumps).

As a result of the review of these requirements and the previous BSER determination, the EPA is proposing methane and VOC standards in NSPS OOOOb for natural gas-driven pneumatic pumps located in all segments of the source category. Specifically, the EPA is proposing that each natural gas driven pneumatic pump is an affected facility. The EPA is proposing that methane and VOC emissions from natural gas-driven diaphragm and piston pumps at well sites and all other sites in the production segment be reduced by 95.0 percent or routed to a process, provided that there is an existing control device onsite or it is technically feasible to route the emissions to a process. For natural gas driven pneumatic pumps at natural gas transmission stations and natural gas storage facilities, the same requirement applies, but only to diaphragm pumps. The EPA is proposing to retain the technical infeasibility provisions of NSPS OOOOa for purposes of NSPS OOOOb. If there is a control device onsite,[294] the owner or operator is not required to route emissions to that control device if it is not technically feasible to do so, even for new construction sites which the EPA had previously referred to as ''greenfield'' sites. The EPA is also proposing to retain in NSPS OOOOb the exception to the 95.0 percent reduction requirement if there is a control device onsite that it is technically feasible to route to that cannot achieve that level of reduction but can achieve a lower level of reductions. In those situations, the emissions from the pump are still to be routed to the control device and controlled at the level that the device can achieve. The EPA is also proposing a prohibition on methane and VOC emissions from pneumatic pumps (diaphragm and piston pumps) at natural gas processing plants. While zero emissions pneumatic pumps would not technically be affected facilities because they are not driven by natural gas, owners and operators should maintain documentation if they would like to be able to demonstrate to permit writers or enforcement officials that there are no methane or VOC emissions from the pumps and that these pumps are not affected facilities subject to the rule.

This BSER for reducing methane and VOC from pneumatic pumps are the same as those for the 2016 NSPS OOOOa, except that (1) the EPA determined that the NSPS OOOOa levels of control also represent BSER for diaphragm pumps at all sites in the production segment (including gathering and boosting stations), and for all transmission and storage sites, and (2) the EPA determined that the NSPS OOOOa levels of control also represent BSER for piston pumps (in addition to diaphragm pumps) in the production segment and at natural gas processing plants.

As discussed below, a primary reason that the EPA is unable to conclude that requiring a natural gas emission rate of zero for production and transmission and storage facilities is BSER at this time is because proven technologies that eliminate natural gas emissions rely on electricity to function. In contrast to pneumatic controllers, our review of information that has become available since the promulgation of the 2016 NSPS OOOOa standards, including State-level regulations for pneumatic pumps, does not demonstrate that zero emission technology for pneumatic pumps would be feasible at sites that lack access to onsite power. The EPA is specifically soliciting comments on the possibility of subcategorizing production and natural gas transmission and storage sites into those sites that have access to onsite power and those that do not, and then determining BSER separately for each subcategory. Further, the EPA is soliciting comment on how, if at all, the proposed NSPS OOOOb standards for pneumatic controllers might factor into how the EPA ought to evaluate the possibility of requiring a natural gas emission rate of zero for pneumatic pumps in the production and transmission and storage segments. For example, if a site installs a solar-powered system to operate their controllers, then could that same system provide power to the pumps such that all pumps at the site could have zero emissions of natural gas?

b. Description

A pneumatic pump is a positive displacement reciprocating unit generally used by the Oil and Natural Gas Industry for one of four purposes: (1) Hot oil circulation for heat tracing/freeze protection, (2) chemical injection, (3) moving bulk liquids, and (4) glycol circulation in dehydrators. There are two basic types of pneumatic pumps used in the Oil and Natural Gas Industry, diaphragm pumps and piston pumps. Pumps used for heat tracing/freeze protection circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks. These heat tracing/freeze protection pumps are usually diaphragm pumps. Chemical injection pumps are designed to inject precise amounts of chemical into a process stream to regulate operations of a plant and protect the equipment. Typical chemicals injected in an oil or gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H_2S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Since the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected. These chemical injection pumps are primarily piston pumps, although they can be small diaphragm pumps. Examples of the use of pneumatic pumps to transfer bulk liquids at oil and natural gas production sites include pumping motor oil or pumping out sumps. Pumps used for these purposes ae typically diaphragm pumps.

Glycol dehydrator pumps recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber. Glycol dehydrator pumps are controlled under the oil and gas NESHAPs (40 CFR part 63, subparts HH and HHH), are not included as affected facilities for the 2016 NSPS OOOOa and were not included in the review for proposed NSPS OOOOb.

Both diaphragm and piston pumps are positive displacement reciprocating pumps, meaning they use contracting and expanding cavities to move fluids. These pumps work by allowing a fluid (*e.g.,* the heat transfer fluid, demulsifier, corrosion inhibitor, etc) to flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. The piston and diaphragm pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge

[294] For the same reasons discussed in section X.B.2, the EPA is proposing that boilers and process heaters are not control devises for purposes of controlling emissions from pneumatic pumps.

the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.

Diaphragm pumps work by flexing the diaphragm out of the displacement chamber, and piston pumps typically include plunger pumps with a large piston on the gas end and a smaller piston on the liquid end to enable a high discharge pressure with a varied but much lower pneumatic supply gas pressure.

As noted above, energy is supplied to the driver side of the pump to operate the piston or diaphragm. Commonly, this energy is provided by pressurized gas. This gas can be compressed air, or ''instrument air,'' provided by an electrically powered air compressor. In many situations across all segments of this industry, electricity is not available, and this energy is provided by pressurized natural gas (*i.e.,* ''natural gas-driven pneumatic pumps''). This energy can also be directly provided by electricity.

Natural gas-driven pneumatic pumps emit methane and VOC as part of their normal operation. These emissions occur when the gas used in the pump stroke is exhausted to enable liquid filling of the liquid cavity of the pump. Emissions are a function of the amount of fluid pumped, the pressure of the pneumatic supply gas, the number of pressure ratios between the pneumatic supply gas pressure and the fluid discharge pressure, and the mechanical inefficiency of the pump.

The 2021 U.S. GHGI estimates almost 215,000 metric tpy of methane emissions from pneumatic pumps in the oil and natural gas production segment in 2019. Specifically, this includes almost 113,000 metric tpy from natural gas production, 75,000 from petroleum production, and 26,000 from gathering and boosting compressor stations. These emissions make up 5 percent of all methane emissions in the GHGI for the combined gas and oil production segment, and 2 percent of all methane emissions for gathering and boosting. The overall total, which represents 3 percent of the total methane emissions from this industry, does not include emissions from the processing, transmission, and storage segments which the EPA is now proposing to regulate under NSPS OOOOb.

c. 2021 BSER Analysis

BSER was evaluated for all segments of the industry. The 2015 NSPS OOOOa proposal included methane and VOC standards for pneumatic pumps in the production and transmission and storage segments. However, the EPA did not finalize regulations for pneumatic pumps at gathering and boosting stations in the final 2016 NSPS OOOOa due to lack of data on the prevalence of the use of pneumatic pumps at gathering and boosting stations. Since that time, GHGRP subpart W has required that emissions from natural gas-driven pneumatic pumps be reported from gathering and boosting stations. As reported above, the 2021 GHGI estimates over 26,000 metric tpy of methane emissions from these pumps in the gathering and boosting segment in 2019. Similarly, the EPA did not include pneumatic pumps in the transmission and storage segment in the final 2016 NSPS OOOOa because we did not have a reliable source of information indicating the prevalence of pneumatic pumps or their emission rates in the transmission and storage segment. While the GHGI does not include emissions from pneumatic pumps in the transmission and storage segment, and the GHGRP does not require the reporting of emissions from these pumps in this segment, State rules (notably the California rule and the proposed New Mexico rule) do include requirements for natural gas driven pneumatic pumps at transmission and storage facilities. The EPA is soliciting comment on whether natural gas driven pneumatic pumps are used in the natural gas transmission and storage segment and to what extent.

In 2015, the EPA identified several options for reducing methane and VOC emissions from natural gas-driven pumps in the production and natural gas transmission and storage segments: Replace natural gas-driven pumps with instrument air pumps, replace natural gas-driven pumps with solar-powered direct current pumps (solar pumps), replace natural gas-driven pumps with electric pumps, route natural gas-driven pump emissions to a control device, and route natural gas-driven pump emissions to a process. The only option identified in 2015 and analyzed at natural gas processing plants was the use of instrument air. The EPA re-evaluated that information as well as new information including updated GHGI and GHGRP information, as well as information from more recent State regulations. No additional options were identified at this time. Therefore, for this analysis for the NSPS, the EPA re-evaluated these options as BSER. In the discussion below, the options to require technology that would eliminate methane and VOC emissions by requiring the use of a non-natural gas driven pumps are discussed, followed by a discussion of routing natural gas driven pumps to a control device.

With the exception of the evaluation of instrument air systems, the BSER analysis for pneumatic pumps was conducted on an individual pump basis. Due to the differences in the level of emissions, we conducted the BSER analysis separately for natural gas-driven diaphragm pneumatic pumps and natural gas-driven piston pneumatic pumps for the production and transmission and storage segments. The emission factor for diaphragm pneumatic pumps is 3.46 tpy of methane, while it is only 0.38 tpy of methane for piston pumps. The corresponding VOC emission factors are 0.96 tpy for the production segment and 0.096 tpy for the transmission and storage segment for diaphragm pumps, and 0.11 and 0.01 tpy for piston pumps, for production and transmission and storage segment, respectively.

For instrument air systems, the BSER analysis was conducted using model plants that included combinations of diaphragm and piston pumps. For example, the smallest model plant included two diaphragm pumps and two piston pumps. Therefore, the cost effectiveness calculated for these instrument air systems represents the cost to eliminate emissions from both types of pumps. Since instrument air was the only option evaluated for natural gas processing plants, the BSER determination was made for all pumps at the plants (as opposed to separate determinations for diaphragm and piston pumps).

Zero Emissions Options

For this analysis, we first evaluated the options that would eliminate methane and VOC emissions from pneumatic pumps, specifically instrument/compressed air systems, electric pumps, and solar-powered pumps.

Instrument air systems require a compressor, power source, dehydrator, and volume tank. No alterations are needed to the pump itself to convert from using natural gas to instrument air. However, they can only be utilized in locations with sufficient electrical power. Instrument air systems are more economical and, therefore, more common at facilities with a high concentration of pneumatic devices and where an operator can ensure the system is properly functioning. Electric pumps provide the same functionality as gas-driven pumps and are only restricted by the availability of a source of electricity.

Solar-powered pumps are a type of electric pump, except that the power is

provided by solar-charged direct current (DC). Solar-powered pumps can be used at remote sites where a source of electricity is not available, and they have been shown to be able to handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 pounds per square inch gauge (psig).

Production and Transmission and Storage Segments. For the production and transmission and storage segments, we evaluated the costs and impacts of these ''zero-emissions'' options (See Chapter 9 of the NSPS OOOOb and EG TSD for this rulemaking). We found that the cost-effectiveness of these options, for both diaphragm and piston pumps, were generally within the ranges that the EPA considers reasonable. However, for instrument air systems and electric pumps, our analysis assumes that electricity is available onsite. As noted above, in 2015, the EPA determined that a zero-emission standard for pumps in the production and transmission and storage segments was infeasible because (1) electricity is not available at all sites and (2) solar pumps are not technically feasible in all situations for which piston pumps and diaphragm pumps are needed. 80 FR 56625–56626. While we specifically requested comment on this determination in 2015, nothing was submitted at that time that caused a reversal in this decision. At this time, we are unclear as to whether these limitations have been overcome and whether zero-emission pneumatic pumps are technically feasible for all pneumatic pumps throughout the production and transmission and storage segments. Therefore, at this time, we are unable to conclude that this zero-emission option represents BSER in this proposal, but we are soliciting comment on this issue to better understand whether a zero-emission option is now technically feasible.

As explained in Section XII.C.1.e, the EPA believes that similar previously identified technical limitations have been overcome in the context of pneumatic controllers. Further, a few States do prohibit emissions from pneumatic pumps throughout the Crude Oil and Natural Gas Industry. California prohibits the venting of natural gas to the atmosphere from pneumatic pumps through the use of compressed air or electricity, or by collecting all potentially vented natural gas with the use of a vapor collection system that undergoes periodic leak detection and repair. While California requires this, the fact that other States (*e.g.,* Colorado, Wyoming) do not require zero emissions from pneumatic pumps at all locations leads us to be uncertain as to whether it is technically feasible at this time. Canadian Provinces also regulate emissions from natural gas-driven pneumatic pumps. In British Columbia, pneumatic pumps installed after January 1, 2021, must not emit natural gas, and in Alberta, vent gas from pneumatic pumps installed after January 2, 2022, must be prevented. In addition, New Mexico has proposed a regulation that requires zero-emitting pumps, but only at production and transmission and storage sites that have access to electricity.

The EPA is soliciting comment on the basis for our proposed determination: That because electricity is not available at all sites and that there are applications at these sites where solar-powered pumps may not be feasible the Agency is uncertain as to whether the zero-emission options represent BSER. Also, as noted above, we are soliciting comment on an approach where the EPA would propose to subcategorize pneumatic pumps located in the production and transmission and storage sites based on availability of electricity and develop separate standards for each subcategory.

Natural gas processing plants. Natural gas processing plants are known to have a source of electrical power. Therefore, instrument air and electric pumps are technically feasible options at these facilities.

As the next step in the BSER determination, we evaluated capital and annual costs of compressed air systems for the natural gas processing plants. While electric pumps are an option at natural gas processing plants, we assumed that natural gas processing plants will elect to always use instrument air and an impacts analysis for electric pumps was not conducted.

The capital costs for an instrument air system were estimated to range from $4,500 to $39,500. The annual costs include the capital recovery cost (calculated at a 7 percent interest rate for 10 years), labor costs for operations and maintenance, and electricity costs. These are estimated to range from $11,300 to $81,350. Because gas emissions are avoided as compared to the use of natural gas-driven pumps, the use of an instrument air system will have natural gas savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 201 Mcf per year of natural gas from being emitted and each piston pump will save of 22 Mcf per year in the processing segment. The estimated value of the natural gas saved, based on $3.13 per Mcf, would range from $1,400 to $35,000 per year per plant. The annual costs, including these savings, ranges from $9,900 to $46,500. More information on this cost analysis is available in the NSPS OOOOb and EG TSD for this proposal.

The resulting cost effectiveness, under the single pollutant approach where all the costs are assigned to the reduction of one pollutant, for the application of instrument air to achieve a 100 percent emission reduction at natural gas processing plants ranges from $420 to $1,470 per ton of methane eliminated. For VOC, these cost effectiveness values ranged from $1,520 to $5,290 per ton of VOC eliminated. Considering savings, these cost effectiveness values range from $240 to $1,300 per ton of methane eliminated and $870 to $4,600 per ton of VOC eliminated. Under the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, the cost effectiveness ranges from $210 to $730 per ton of methane eliminated and $760 to $2,640 per ton of VOC eliminated. Considering savings, the cost effectiveness values range from $120 to $650 per ton of methane eliminated and from $440 to $2,320 per ton of VOC eliminated. These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches. As discussed above, the evaluation for instrument air systems is based on a combination of diaphragm and piston pumps. Therefore, this determination of reasonableness applies to both types of pumps at natural gas processing plants.

The 2016 NSPS OOOOa requires a natural gas emission rate of zero for pneumatic pumps at natural gas processing plants. Natural gas processing plants have successfully met this standard. Further, as discussed above several State agencies have rules that include this zero-emission requirement. This is a demonstration of the reasonableness of a natural gas emission rate of zero for pneumatic pumps at natural gas processing plants.

Secondary impacts from the use of instrument air systems are indirect, variable, and dependent on the electrical supply used to power the compressor. These impacts are expected to be minimal, and no other secondary impacts are expected.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven piston and diaphragm pumps at gas processing plants is a natural gas emission rate of zero. This option results in a 100 percent reduction of emissions for both methane and VOC. Therefore, for NSPS OOOOb, we are

proposing to require a natural gas emission rate of zero for all pneumatic pumps at natural gas processing plants.

Routing to a Control Device or VRU Options

Above we stated our determination that the EPA is unable to conclude that this zero-emission option represents BSER in this proposal for pumps in the production and transmission and storage segments. Therefore, we evaluated the use of control devices to reduce methane and VOC emissions. This BSER analysis was conducted on an individual pump basis and diaphragm and piston pumps were evaluated separately.

Combustors (*e.g.,* enclosed combustion devices, thermal oxidizers and flares that use a high-temperature oxidation process) can be used to control emissions from natural gas-driven pumps. Combustors are used to control VOCs in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and inert species content. The types of combustors installed in the Crude Oil and Natural Gas Industry can achieve at least a 95 percent control efficiency on a continuous basis. It is noted that combustion devices can be designed to meet 98 percent control efficiencies, and can control, on average, emissions by 98 percent or more in practice when properly operated. However, combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice in the oil and gas industry due to factors such as variability of field conditions.

A related option for controlling emissions from pneumatic pumps is to route vapors from the pump to a process, such as back to the inlet line of a separator, to a sales gas line, or to some other line carrying hydrocarbon fluids for beneficial use, such as use as a fuel. Use of a VRU has the potential to reduce the VOC and methane emissions from natural gas-driven pneumatic pumps by 100 percent if all vapor is recovered. However, the effectiveness of the gas capture system and downtime for maintenance would reduce capture efficiency and therefore, we estimate that routing emissions from a natural gas-driven pump to a VRU and to a process can reduce the gas emitted by approximately 95 percent, while at the same time, capturing the gas for beneficial use.

Based on a 95 percent reduction, the reduction in emissions in the production segment would be 3.29 tpy of methane and 0.91 tpy of VOC per diaphragm pump, and 0.36 tpy methane and 0.10 tpy VOC per piston pump. In the transmission and storage segment, the reduction in emissions would be 3.29 tpy of methane and 0.09 tpy of VOC per diaphragm pump, and 0.36 tpy of methane and 0.01 ton per year of VOC per piston pump.

Installation of a new combustion device or VRU. Costs for the installation of a new combustion device and a new VRU were evaluated. Installing a new combustion device has associated capital costs and operating costs. Based on the analysis conducted for the 2012 NSPS for a combustion device to control emissions from storage vessels, the capital cost for installing a new combustion device was $32,300 in 2008 dollars. We updated this to $38,500 to reflect 2019 dollars. Based on the life expectancy for a combustion device at 10 years, we estimate the annualized capital cost of installing a new combustion device to be $5,500 in 2019 dollars, using a 7 percent discount rate. The 2016 NSPS OOOOa TSD indicates the annual operating costs associated with a new combustion device were $17,000 in 2012 dollars, which we updated to $19,100 in 2019 dollars. Therefore, the total annual costs for a new combustion device are $24,600. Because the gas captured is combusted there are no gas savings associated with the use of a combustion device.

Installing a new VRU would also have both capital costs and maintenance costs. We based the costs of a VRU on the analysis conducted for the 2012 NSPS for control of emissions from storage vessels, which is representative of the costs that would be incurred for a VRU used to reduce emissions from natural gas-driven pneumatic pumps. The capital cost and installation costs for a new VRU are estimated to be $116,900 (in 2019 dollars) and the annual operation and maintenance costs estimated to be $11,200 (in 2019 dollars). The total annualized cost of a new VRU is estimated to be $27,800, including the operation and maintenance cost and the annualized capital costs based on a 7 percent discount rate and 10-year equipment life.

Because there is potential for beneficial use of gas recovered through the VRU, the savings that would be realized for 95 percent of the gas that would have emitted and lost were estimated. The gas saved would equate to 191 Mcf per year from a diaphragm pump and 21 Mcf per year from a piston pump. This results in estimated annual savings of $600 per diaphragm pump and $65 per piston pump in the production segment. The resulting annual costs, considering these savings, are $27,200 per diaphragm pump and $27,700 per piston pump in the production segment. Transmission and storage facilities do not own the natural gas; therefore, savings from reducing the amount of natural gas emitted/lost was not applied for this segment. More information on these cost analyses is available in the NSPS OOOOb and EG TSD for this proposal.

The resulting cost effectiveness estimates for application of a new control device to reduce emissions from natural gas-driven pumps in the production segment by 95 percent, or the use of a VRU to route emissions back to a process, are discussed below under both the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, and the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction. The results are presented separately for diaphragm and piston pumps. These values assume that the control device or VRU is installed solely for the purpose of controlling the emissions from a single natural gas-driven pneumatic pump, and only the emission reductions from a single pump are considered.

For diaphragm pumps in the production segment using the single pollutant approach, the cost effectiveness is estimated to be $7,500 per ton of methane reduced using a new combustion device, and $8,500 using a new VRU ($8,300 with savings). For VOC, these cost effectiveness values are $26,900 per ton of VOC reduced using a new combustion device, and $30,400 using a new VRU ($29,800 with savings). These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For diaphragm pumps in the production segment using the multipollutant approach, the cost effectiveness is estimated to be $3,750 per ton of methane reduced using a new combustion device, and $4,250 using a new VRU ($4,150 with savings). For VOC, these cost effectiveness values are $13,450 per ton of VOC reduced using a new combustion device, and $15,200 using a new VRU ($14,900 with savings). These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For piston pumps in the production segment using the single pollutant approach, the cost effectiveness is estimated to be $68,100 per ton of methane reduced using a combustion device, and $77,000 using a VRU ($76,800 with savings). For VOC, these cost effectiveness values are $244,800

per ton of VOC reduced using a combustion device, and $277,000 using a VRU ($276,400 with savings). These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For piston pumps in the production segment using the multipollutant approach, the cost effectiveness is estimated to be $34,000 per ton of methane reduced using a combustion device, and $38,500 using a VRU ($38,400 with savings). For VOC, these cost effectiveness values are $122,400 per ton of VOC reduced using a combustion device, and $138,500 using a VRU ($138,200 with savings). These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For diaphragm pumps in the transmission and storage segment using the single pollutant approach, the cost effectiveness is estimated to be $7,400 per ton of methane reduced using a new combustion device, and $8,500 using a new VRU. For VOC, these cost effectiveness values are $270,000 per ton of VOC reduced using a new combustion device, and $305,000 using a new VRU. These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For diaphragm pumps in the transmission and storage segment using the multipollutant approach, the cost effectiveness is estimated to be $3,700 per ton of methane reduced using a new combustion device, and $4,200 using a new VRU. For VOC, these cost effectiveness values are $135,000 per ton of VOC reduced using a new combustion device, and $152,600 using a new VRU. These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For piston pumps in the transmission and storage segment using the single pollutant approach, the cost effectiveness is estimated to be $68,000 per ton of methane reduced using a combustion device, and $77,000 using a VRU. For VOC, these cost effectiveness values are $2.5 million per ton of VOC reduced using a combustion device, and $2.8 million using a VRU. These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For piston pumps in the transmission and storage segment using the multipollutant approach, the cost effectiveness is estimated to be $34,000 per ton of methane reduced using a combustion device, and $38,500 using a VRU. For VOC, these cost effectiveness values are $1.2 million per ton of VOC reduced using a combustion device, and $1.4 million using a VRU. These values are outside of the range considered reasonable by the EPA for both methane and VOC.

For diaphragm pumps, we do not consider the costs to be reasonable to install a new control device, or a new VRU to route the emissions to a process, for the production and transmission and storage segments for methane or VOC emission reduction using either the single pollutant or multipollutant approach. Similarly, for piston pumps, we do not consider the costs to be reasonable under any scenario. Therefore, we are unable to conclude that requiring the installation of a new control device, or the installation of a new VRU to route emissions to a process, to achieve 95 percent reduction of methane and VOC emissions from natural gas-driven pumps for the production or transmission segments represents BSER in this proposal.

Routing to an existing combustion device or VRU. In addition to evaluating the installation of a new control device or new VRU installed solely for the purpose of reducing the emissions from a single natural gas-driven pneumatic pump, we evaluated the option of routing the emissions from natural gas-driven pneumatic pumps to an existing control device to achieve a 95 percent reduction in methane and VOC emissions or routing the emissions to an existing VRU and to a process. The emission reduction for this option would be the same as discussed above for a new control device achieving 95 percent control, that is 3.29 tpy of methane and 0.91 tpy of VOC per diaphragm pump, and 0.36 tpy methane and 0.10 tpy VOC per piston pump in the production segment and 3.29 tpy of methane and 0.09 tpy of VOC per diaphragm pump, and 0.36 tpy of methane and 0.01 ton per year of VOC per piston pump in the transmission and storage segment. The resulting cost effectiveness estimates for use of an existing control device to reduce emissions from natural gas-driven pumps in the production segment by 95 percent, or the use of an existing VRU to route emissions to a process, are discussed below under both the single pollutant approach, where all the costs are assigned to the reduction of one pollutant, and the multipollutant approach, where half the cost of control is assigned to the methane reduction and half to the VOC reduction. The results are presented separately for diaphragm and piston pumps.

We estimated the costs for routing emissions to an existing control device or VRU based on the average of the cost presented in the 2015 proposed NSPS OOOOa and the costs presented by two commenters to the proposal,[295] as documented in the 2016 NSPS OOOOa TSD. This yielded a capital cost estimate of $6,100 in 2019 dollars, for an annualized cost of $900 in 2019 dollars, using the 7 percent discount rate and 10-year equipment life. In the 2016 NSPS OOOOa TSD the EPA assumed there were no incremental operating costs for routing to an existing control device or VRU, so the total annual costs consist only of the $900 capital recovery cost. This assumption is maintained for this analysis. The same savings discussed above for the gas that is recovered by a VRU would be realized when routing to an existing VRU and to a process. These savings are $600 per year per diaphragm pump and $65 per year per piston pump in the production segment. The resulting annual costs for routing to an existing VRU and to process, considering these savings, are $270 per diaphragm pump and $800 per piston pump in the production segment. As noted above, transmission and storage facilities do not own the natural gas; therefore, savings from reducing the amount of natural gas emitted/lost was not applied for this segment.

For diaphragm pumps in the production segment using the single pollutant approach, the cost effectiveness is estimated to be $260 per ton of methane reduced using an existing combustion device, and $260 per ton of methane using an existing VRU ($80 with savings). For VOC, these cost effectiveness values are $950 per ton of VOC reduced using an existing combustion device, and $950 using an existing VRU ($300 with savings). For diaphragm pumps in the production segment using the multipollutant approach, the cost effectiveness is estimated to be $130 per ton of methane reduced using an existing combustion device, and $130 using an existing VRU ($40 with savings). For VOC, these cost effectiveness values are $475 per ton of VOC reduced using an existing combustion device, and $475 using an existing VRU ($150 with savings). These values are well within the range of what the EPA considers to be reasonable for methane and VOC using both the single pollutant and multipollutant approaches.

For diaphragm pumps in the transmission and storage segment using the single pollutant approach, the cost effectiveness is estimated to be $260 per ton of methane reduced using an existing combustion device, and $260 using an existing VRU. For VOC, these

[295] EPA–HQ–OAR–2010–0505–6884–A1 and EPA–HQ–OAR–2010–0505–6881.

cost effectiveness values are $9,500 per ton of VOC reduced using an existing combustion device, and $9,500 using an existing VRU. For diaphragm pumps in the transmission and storage segment using the multipollutant approach, the cost effectiveness is estimated to be $130 per ton of methane reduced using an existing combustion device, and $130 using an existing VRU. For VOC, these cost effectiveness values are $4,800 per ton of VOC reduced using an existing combustion device, and $4,800 using an existing VRU. These values are within the range of what the EPA considers to be reasonable.

The 2016 NSPS OOOOa requires that emissions from natural gas driven pneumatic pumps at well sites achieve a 95 percent reduction in methane and VOC emissions by routing them to a control device if an existing control device is on site. Owners and operators at well sites have successfully met this standard. Further, several State agencies (*e.g.,* California, proposed in New Mexico) have rules that include this requirement, and have extended the requirement to sites throughout the production segment as well as the transmission and storage segment. These factors considered together demonstrate the reasonableness of a requirement that emissions from natural gas driven pneumatic pumps at sites without access to electricity achieve a 95 percent reduction in methane and VOC emissions by routing them to a control device, provided that an existing control device is on site.

There are secondary impacts from the use of a combustion device to control emissions routed from natural gas-driven diaphragm pumps. The combustion of the recovered natural gas creates secondary emissions of hydrocarbons, NO_X, CO_2, and CO. The EPA considers the magnitude of these emissions to be reasonable given the significant reduction in methane and VOC emissions that the control would achieve. Details of these impacts are provided in the NSPS OOOOb and EG TSD for this rulemaking. There are no other wastes created or wastewater generated. The secondary impacts from use of a VRU are indirect, variable, and dependent on the electrical supply used to power the VRU. No other secondary impacts are expected.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven diaphragm pumps in the production and transmission and storage segments is to route the emissions to an existing control device that achieves 95 percent control of methane and VOC, or to route the emissions to an existing VRU and to a process. We are, therefore, proposing to include this requirement in NSPS OOOOb.

For piston pumps in the production segment using the single pollutant approach, the cost effectiveness is estimated to be $2,400 per ton of methane reduced using a combustion device, and $2,400 using a VRU ($2,200 with savings). For VOC, these cost effectiveness values are $8,700 per ton of VOC reduced using a combustion device, and $8,700 using a VRU ($8,000 with savings).

For piston pumps in the production segment using the multipollutant approach, the cost effectiveness is estimated to be $1,200 per ton of methane reduced using a combustion device, and $1,200 using a VRU ($1,100 with savings). For VOC, these cost effectiveness values are $4,350 per ton of VOC reduced using a combustion device, and $4,350 using a VRU ($4,000 with savings).

For piston pumps in the production segment, we do not consider the costs to route emissions from a natural gas-driven pneumatic pump to an existing control device to achieve 95 percent reduction, or to route to an existing VRU and to a process, to be reasonable for methane or VOC using the single pollutant approach. However, the methane and VOC cost effectiveness using the multipollutant method is within the range that the EPA considers reasonable.

There are secondary impacts from the use of a combustion device to control emissions routed from natural gas-driven piston pumps. These impacts are the same as discussed above for diaphragm pumps.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven piston pumps in the production and transmission and storage segments is to route the emissions to an existing control device that achieves 95 percent control of methane and VOC, or to route the emissions to an existing VRU and to a process. We are, therefore, proposing to include this requirement for piston pumps in NSPS OOOOb.

The EPA notes that State rules for concerning natural gas-driven piston pumps emissions control requirements differ. For example, California specifically includes both diaphragm and piston pumps in the definition of pneumatic pumps, while Colorado specifically excludes piston pumps from control requirements. At this time, the EPA is unable to fully understand the basis for the piston pump State control requirement differences based on the background information for these State rules.

We are specifically seeking comment on the emissions factors used to estimate the baseline emissions from pneumatic pumps, which are from a 1996 EPA/GRI study.[296] The EPA is interested in more recent information regarding emissions from pneumatic pumps.

For piston pumps in the transmission and storage segment using the single pollutant approach, the cost effectiveness is estimated to be $2,400 per ton of methane reduced using a combustion device, and $2,400 using a VRU. For VOC, these cost effectiveness values are $87,000 per ton of VOC reduced using a combustion device, and $87,000 using a VRU.

For piston pumps in the transmission and storage segment using the multipollutant approach, the cost effectiveness is estimated to be $1,200 per ton of methane reduced using a combustion device, and $1,200 using a VRU. For VOC, these cost effectiveness values are $43,500 per ton of VOC reduced using a combustion device, and $43,500 using a VRU.

For piston pumps in the transmission and storage segment, we do not consider the costs to be reasonable to route emissions from a natural gas-driven pneumatic pump to an existing control device, or to route to an existing VRU and to a process, for either methane or VOC under the single pollutant approach. Further, we do not find that the cost effectiveness for both methane and VOC to be reasonable under the multipollutant approach. Therefore, we are unable to conclude that requiring the routing of emissions from natural gas-driven piston pumps in the transmission and storage segment to an existing control device to achieve 95 percent reduction of methane and VOC emissions, or the routing of emissions to a VRU and to a process, represents BSER for NSPS OOOOb in this proposal.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing pneumatic pumps (designated facilities) in all segments in the Crude Oil and Natural Gas source category covered by the proposed NSPS OOOOb and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities

[296] Gas Research Institute (GRI)/U.S. Environmental Protection Agency. 1996d. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps.* June 1996 (EPA–600/R–96–080m).

that mirrors the proposed NSPS OOOOb, with the exception of the BSER conclusion regarding piston pumps in the production segment.

First, based on the same criteria and reasoning explained above the EPA is proposing to define the designated facility in the context of existing pneumatic pumps as those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should alter this definition as applied to existing sources.

The EPA finds that the controls evaluated for new sources for NSPS OOOOb are appropriate for consideration for existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission reduction, for pneumatic pumps that could be used for existing sources but not for new sources. Next, the methane emission reductions expected to be achieved via application of the control measures identified above to new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

The EPA has not identified any costs associated with applying these controls at existing sources, such as retrofit costs, that would apply any differently than, or in addition to, those costs assessed above regarding application of the identified controls to new sources. The cost effectiveness values for the option of zero emissions from pneumatic pumps in the natural gas processing sector range from $420 to $1,470 per ton of methane eliminated ($240 to $1,300 per ton considering savings). These cost effectiveness values are in the range considered reasonable by the EPA. However, as explained above in the context of new sources, at this time we are unclear as to whether the technical limitations associated with this option have been overcome and whether zero-emission pneumatic pumps are technically feasible. Therefore, at this time, we are unable to conclude that this zero-emission option represents BSER in this proposal for the EG, but we are soliciting comment on this issue to better understand whether a zero-emission option is technically feasible.

For diaphragm pumps in the production segment the cost effectiveness is estimated to be $260 per ton of methane reduced using an existing (on site) combustion device or VRU, and $260 per ton of methane using an existing (on site) VRU ($80 with savings). For diaphragm pumps in the transmission and storage segment the cost effectiveness of is estimated to be $260 per ton of methane reduced using an existing (on site) combustion device, and $260 using an existing (on site) VRU. This cost effectiveness is considered reasonable by the EPA.

For piston pumps in the production segment the cost effectiveness is estimated to be $2,400 per ton of methane reduced using an existing (on site) combustion device or VRU, and $2,400 per ton of methane using an existing (on site) VRU ($2,200 with savings). For piston pumps in the transmission and storage segment the cost effectiveness is estimated to be $2,400 per ton of methane reduced using an existing (on site) combustion device, and $2,400 using an existing (on site) VRU. This cost effectiveness is outside of the range considered reasonable by the EPA. In summary, the EPA did not identify any factors specific to existing sources, as opposed to new sources, that would alter the analysis above for the proposed NSPS OOOOb as applied to the designated pollutant (methane) and the designated facilities (pneumatic pumps). However, the BSER conclusion regarding piston pumps in the production and transmission and storage segments for the EG differs from the conclusion for new sources under the NSPS. As a result, the proposed presumptive standards for existing pneumatic pumps are as follows.

For diaphragm pneumatic pumps in the production and transmission and storage segments, the presumptive standard is routing emissions to an existing (already on site) control device or existing (already on site) VRU and to a process to achieve 95 percent reduction in methane. For pneumatic pumps (diaphragm and piston) in the natural gas processing sector, the presumptive standard is a natural gas emission rate of zero.

As for new sources, the EPA is specifically soliciting comment on whether the production and transmission storage segments should be subcategorized based on the availability of electricity and BSER determined separately for each subcategory in the EG.

H. Proposed Standards for Equipment Leaks at Natural Gas Processing Plants

1. NSPS OOOOb

a. Background

In the 2012 NSPS OOOO, the EPA established VOC standards for equipment leaks at onshore natural gas processing plants. These standards were based on the Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (NSPS VVa), which is an EPA Method 21 LDAR program generally requiring monthly monitoring of pumps with a leak definition of 2,000 ppm, quarterly monitoring of valves with a leak definition of 500 ppm, and annual monitoring of connectors with a leak definition of 500 ppm.[297] In the 2016 NSPS OOOOa, the EPA added GHG (methane) to the title of the standards for equipment leaks at onshore natural gas plants but continued to rely on the requirements in NSPS VVa, which limited monitoring and repair (if found leaking) to those equipment components ''in VOC service.'' Based on our review of the current standards, we are proposing to revise the equipment leak standards for onshore natural gas plants to more readily apply to equipment components that have the potential to emit methane even though they are not ''in VOC service.''

b. Technology and LDAR Program Review

The EPA acknowledges that advancements are being made in leak detection, including remote sensing, sensor networks, and OGI. The EPA already provides use of OGI as an alternative work practice at 40 CFR 60.18(g); however, the alternative work practice requires annual EPA Method 21 monitoring as part of the OGI monitoring protocol. Parallel with this proposal, the EPA is proposing appendix K to part 60 to provide a standard method for OGI leak monitoring. This allows us to consider a wider range of LDAR programs when evaluating the BSER for equipment leaks at onshore natural gas processing plants. To evaluate different LDAR programs, we used a Monte Carlo simulation that simulated initiation of leaks for pumps, valves, and connectors at monthly intervals based on

[297] 40 CFR part 60, subpart VVa, includes ''skip period'' provisions that may alter the cited monitoring frequencies.

component specific leak frequencies and EPA Method 21 leak size distributions based on historical EPA Method 21 leak data. We randomly assigned a mass emission rate based on the EPA Method 21 leak size assuming a lognormal distribution for the mass emission rate around the EPA Method 21 screening value correlation equation estimates. The simulation runs for five years for each LDAR program to build up leaks that might not be repaired under a given program, and compares the emissions estimated in the fifth year of the simulation for different LDAR programs. The model also records the number of repairs made in the fifth year of the simulation to assess the annual repair costs associated with the LDAR program. More information on the LDAR program Monte Carlo simulation and associated cost analyses is available in the NSPS OOOOb and EG TSD for this proposal.

Based on our model simulation of NSPS OOOOa requirements (Method 21 based LDAR program following the requirements in NSPS VVa), the EPA projects that the program achieves a 91.5 percent emission reduction for the components monitored. This is comparable to the projected control efficiencies of this LDAR program applied to similar industrial processes.[298] However, when considering the components not monitored at the onshore natural gas processing plant because they are not ''in VOC service'', the overall hydrocarbon control efficiency of the current NSPS OOOOa requirements drops to 73.2 percent. Thus, significant emission reductions can be achieved by extending the current provisions to include all components that have the potential to emit methane.

Based on our model simulation of an OGI-based LDAR program, we found that bimonthly OGI monitoring of all equipment components (with potential VOC or methane emissions) using devices capable of identifying mass leaks at 30 g/hr and at 15 g/hr would achieve emission reductions of 88.5 percent and 92.2 percent, respectively. Based on the requirements in appendix K that the instrument be able to detect a methane leak of 17 g/hr, these results suggest that bimonthly OGI monitoring following appendix K will achieve comparable emission reductions as the current NSPS OOOOa requirements for the equipment components subject to the monitoring requirements.

c. Control Options and 2021 BSER Analysis

The EPA then evaluated various LDAR programs for their control efficiency, cost and cost effectiveness for a small and a large model natural gas processing plant. These ''small'' and ''large'' model plants were based on the number of components at each facility in various monitoring summaries for onshore natural gas processing plants.[299] We considered the (option 1) current NSPS OOOOa standards expanded to components that also have the potential to emit methane regardless of the VOC content of the stream, (option 2) bimonthly OGI following appendix K for all components (VOC or methane), and (options 3 and 4) a hybrid approach following the current alternative work practice (regular OGI with annual EPA Method 21). For option 3 we evaluated requiring quarterly OGI with an annual EPA Method 21 survey at 10,000 ppm. For option 4 we evaluated requiring bimonthly OGI with an annual EPA Method 21 survey at 10,000 ppm. These control options and their associated costs are summarized in Tables 18 and 19 for the small and large model plants, respectively.

TABLE 18—SUMMARY OF CONTROL OPTIONS AND COSTS FOR SMALL MODEL PLANTS

Control option	Emissions reduction (tpy)		Capital cost ($)	Annual cost ($/yr)	CE [a] ($/ton VOC)	CE [a] ($/ton methane)	Incremental ($/ton VOC)	Incremental ($/ton methane)
	VOC	Methane						
Methane and VOC Service								
1	12.34	56.95	$17,700	$114,100	$9,200	$2,000	.....	.....
2	12.61	58.19	1,500	62,800	5,000	1,100	−189,100	−41,300
3	12.64	58.33	19,200	84,500	6,700	1,400	696,200	151,100
4	12.76	58.92	19,200	95,500	7,500	1,600	87,000	18,800

[a] Cost effectiveness (CE) compared to no monitoring.

TABLE 19—SUMMARY OF CONTROL OPTIONS AND COSTS FOR LARGE MODEL PLANTS

Control option	Emissions reduction (tpy)		Capital cost ($)	Annual cost ($/yr)	CE [a] ($/ton VOC)	CE [a] ($/ton methane)	Incremental ($/ton VOC)	Incremental ($/ton methane)
	VOC	Methane						
Methane and VOC Service								
1	25.59	118.27	$36,200	$229,000	$9,000	$1,900	.....	.....
2	26.11	120.81	3,000	123,500	4,700	1,000	−200,000	−43,100
3	26.17	121.10	39,200	170,500	6,500	1,400	760,000	165,200
4	26.44	122.31	39,200	191,300	7,200	1,600	79,500	17,100

[a] Cost effectiveness (CE) compared to no monitoring.

We further assumed that all facilities outsource their equipment leak surveys. The first year ''capital'' costs of implementing an EPA Method 21 program (identifying components required to be monitored and developing a data system to track the proper frequency to monitor each component) are summarized in Tables 18 and 19. Additionally, these tables summarize the annualized costs of conducting a complete EPA Method 21

[298] EPA, October 2007. ''Leak Detection and Repair—A Best Practices Guide.'' Office of Enforcement and Compliance Assurance. EPA–305–D–07–001. See ''Table 4.1—Control effectiveness for an LDAR program at a chemical process unit and a refinery.''

[299] See Section 10.4 of Chapter 10 ''Equipment Leaks from Natural Gas Processing Plants'' in the TSD located at Docket ID No. EPA–HQ–OAR–2021–0317.

monitoring survey of all equipment (those in VOC service or contacting methane), which includes the annual costs of conducting required surveys and making the necessary repairs as well as annualized first year ''capital'' costs. The first-year startup costs for OGI surveys are small, estimated to be $750 for small plants and $1,500 for large plants. Because OGI surveys can be conducted much more quickly, the annualized cost of conducting bimonthly OGI surveys is approximately half the annualized cost of EPA Method 21 surveys through NSPS VVa. Both EPA Method 21 and OGI LDAR programs reduce loss of product. Therefore, the costs of the LDAR programs are offset to some degree to the emissions reduced. When evaluating LDAR programs that consider all components (both VOC and methane), the annual value of the product not lost due to reduced emissions is approximately $14,000/yr.

Based on our analysis, the resulting cost effectiveness is reasonable for all of the options when assigning all costs to the reduction of methane. When assigning all costs to VOC reduction, however, only the bimonthly OGI option is considered reasonable at $5,000/ton VOC reduced for small plants and $4,700/ton VOC reduced at large plants. The EPA next considered the incremental cost-effectiveness between the four options to determine which option represents the BSER for equipment leaks at onshore natural gas processing plants. All four options achieve similar emission reductions, as discussed in the previous section. Bimonthly OGI (option 2) reduces an additional 2 tpy of methane at a cost savings. Adding annual EPA Method 21 to bimonthly OGI monitoring (option 4) reduces an additional 1.5 tpy methane for large model gas plant but at significant cost well above any costs the EPA would consider appropriate, at approximately $45,000/ton methane reduced (comparing option 4 with option 2). Therefore, the EPA does not consider it reasonable to require the additional of annual EPA Method 21.

Based on the discussion above, we consider a bimonthly OGI LDAR program following appendix K that includes all equipment components that have the potential to emit VOC or methane to be BSER for new sources. Therefore, we are proposing this LDAR requirement for new sources under NSPS OOOOb. Because an EPA Method 21 monitoring program based on the requirements of NSPS VVa when applied to all equipment components that have the potential to emit VOC or methane is projected to achieve similar emission reductions, we are proposing that this EPA Method 21-based LDAR program may be used as an alternative to bimonthly OGI surveys.

In the development of the 2012 NSPS OOOO, we found that NSPS VVa provisions for PRDs, open-ended valves or lines, and closed vent systems and equipment designated with no detectable emissions were BSER. Available information since then continues to support this conclusion. Therefore, we are proposing to retain the current requirements in the 2016 NSPS OOOOa (which adopts by reference specific provisions NSPS VVa) for PRDs, open-ended valves or lines, and closed vent systems and equipment designated with no detectable emissions, except expanding the applicability to sources that have the potential to emit methane. The EPA is soliciting information that would support the use of the proposed bimonthly OGI monitoring requirement for these equipment components in place of the NSPS VVa annual EPA Method 21 monitoring.

The EPA requests comments on ways to streamline approval of alternative LDAR programs using remote sensing techniques, sensor networks, or other alternatives for equipment leaks at onshore natural gas processing plants. Based on our Monte Carlo equipment leak model that assumes well-implemented LDAR programs with no delayed repair, both an EPA Method 21 based program following NSPS VVa and a bimonthly OGI monitoring program following appendix K are projected to achieve a 91-percent emission reduction effectiveness. We request comment on whether providing such an emission reduction target and equipment leak modeling tool to simulate LDAR under similar ''ideal'' program implementation conditions may facilitate future equivalency determinations.

2. EG OOOOc

The application of an LDAR program at an existing source is the same as at a new source because there is no need to retrofit equipment at the site to achieve compliance with the work practice standard. The cost effectiveness for implementing a bimonthly OGI LDAR program for all equipment components that have the potential to emit methane is approximately $850/ton methane reduced. As explained above, the cost effectiveness of this OGI monitoring option is within the range of costs we believe to be reasonable for methane reductions. Therefore, we consider a bimonthly OGI LDAR program following appendix K that includes all equipment components that have the potential to emit methane to be BSER for existing sources.

I. Proposed Standards for Well Completions

1. NSPS OOOOb

a. Background

Pursuant to CAA section 111(b)(1)(B), the EPA reviewed the current standards in NSPS OOOOa for well completions and proposes to determine that they continue to reflect the BSER for reducing methane and VOC emissions during oil and natural gas well completions following hydraulic fracturing and refracturing. Accordingly, we are not proposing revisions to these standards. Provided below are a description of the affected facilities, the current standards, and a summary of our review.

Natural gas and oil wells all must be ''completed'' after initial drilling in preparation for production. Well completion activities not only will vary across formations but can vary between wells in the same formation. Over time, completion and recompletion activities may change due to the evolution of well characteristics and technology advancement. Well completion activities include multiple steps after the well bore hole has reached the target depth. Developmental wells are drilled within known boundaries of a proven oil or gas field and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rate, and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as ''wildcat'') wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving oil and gas production is to fracture the reservoir rock with very high-pressure fluid, typically a water emulsion with a proppant (generally sand) that ''props open'' the fractures after fluid pressure is reduced. Natural gas emissions are a result of the backflow of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion backflow escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the

backflow eventually contains a higher volume of natural gas from the formation. Due to the specific additional equipment and resources involved and the nature of the backflow of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

During its lifetime, wells may need supplementary maintenance, referred to as recompletions (these are also referred to as workovers). Recompletions are remedial operations required to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere unless the flowback gas is captured.

When hydraulic re-fracturing (recompletions) is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The flowback velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Flowback emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate flowback, with intermittent slugs of water and sand along with free gas, is directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the flowback emissions originate from the recompletion process but are vented as the flowback enters the impoundment or vessels. Minimal amounts of emissions are caused by the fluid (mostly water) held in the impoundment or vessels since very little gas is dissolved in the fluid when it enters the impoundment or vessels.

The 2021 GHGI estimates approximately 34,000 metric tpy of methane emissions from hydraulically fractured completion/workover natural gas well events and approximately 12,000 metric tpy of methane emissions from hydraulically fractured completion/workover oil well events in 2019.

b. Affected Facility

Each affected facility is a single well that conducts a well completion operation following hydraulic fracturing or refracturing.

c. Current NSPS Requirements

The current NSPS for natural gas and oil well completions and recompletions are the same. For well completions of hydraulically fractured (or refractured) wells, the EPA identified two subcategories of hydraulically fractured wells for which well completions are conducted: (1) Non-wildcat and non-delineation wells (subcategory 1 wells); and (2) wildcat and delineation wells and low-pressure wells (subcategory 2 wells). A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or is the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir.

In the 2016 NSPS OOOOa rule, the EPA finalized operational standards for non-wildcat and non-delineation wells (subcategory 1 wells) that required a combination of REC and combustion. Because RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure and/or inert gas concentrations, the rule allows for wellhead owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (*e.g.,* wellhead pressure or inert gas concentrations) by using a completion combustion device. For wildcat and delineation wells and low-pressure wells (subcategory 2 wells), the EPA finalized an operational standard that required either (1) routing all flowback directly to a completion combustion device with a continuous pilot flame (which can include a pit flare) or, at the option of the operator, (2) routing the flowback to a well completion vessel and sending the flowback to a separator as soon as a separator will function and then directing the separated gas to a completion combustion device with a continuous pilot flame. For option 2, any gas in the flowback prior to the point when the separator will function was not subject to control. 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. Under the 2016 NSPS OOOOa rule, oil wells with a gas-to-oil ratio less than 300 scf of gas per stock tank barrel of oil produced are affected facilities but have no requirements other than to maintain records of the low GOR certification and a claim signed by the certifying official. As discussed in section X.B.1 of this preamble, in the 2020 Technical Rule, the EPA made certain amendments (*e.g.,* related to the use of a separator, amended definition of flowback, amended recordkeeping and reporting requirements) to the VOC standards for well completions in the 2016 NSPS OOOOa, and is proposing to apply the same amendments to the methane standards for well completions in the 2016 NSPS OOOOa.

d. 2021 BSER Analysis

The two techniques considered under the previous BSER analyses that have been proven to reduce emissions from production segment well completions and recompletions include REC and completion combustion. REC is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. The second technique, completion combustion, destroys the organic compounds. No other emissions control techniques were identified as being required under other rules (Federal, State, or local rules) that would exceed the level of control required under the 2016 NSPS OOOOa rule. Therefore, no other technology control requirements were evaluated in this review.

Reduced emission completions, also referred to as ''green'' or ''flareless'' completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. However, as the EPA has previously acknowledged, there are some limitations that may exist for performing RECs based on technical barriers. These limitations continue to exist. Three main limitations for performing a REC include the proximity of pipelines to the well, the pressure of the produced gas, and the inert gas

concentration. These limitations are discussed below.

For exploratory wells (in particular), no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The EPA is soliciting comment on how ''access to a sales line'' and a ''sales line'' should be defined.

During the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the gathering line backpressure. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another potential compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor where there is a widely fluctuating flowback rate.

Lastly, if the concentration of inert gas, such as nitrogen or CO_2, in the flowback gas exceeds sales line concentration limits, venting to the atmosphere or to a combustion device of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

Where a REC can be conducted, the achievable emission reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on several experiences presented at Natural Gas STAR technology transfer workshops, this analysis assumes 90 percent of flowback gas can be recovered during a REC.[300] Gas that cannot be recovered during a REC can be directed to a completion combustion device in order to achieve an estimated 95 percent reduction in overall emissions.

Completion combustion devices commonly found on drilling sites are generally crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These flares can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Sometimes referred to as pit flares, these types of combustion devices do not employ an actual control device and are not capable of being tested or monitored for efficiency. They do provide a means of minimizing vented gas and is preferable to venting.

The efficiency of completion combustion devices, or exploration and production flares, can be expected to achieve 90 percent, on average, over the duration of the completion or recompletion.[301] If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (*e.g.,* dry, windy conditions and proximity to residences). As a result, owners and operators may not be able to combust unrecoverable gas safely in every case.

Noise and heat are the two adverse impacts of completion combustion device operations. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including NO_X, CO, sulfur oxides (SO_X), CO_2, and smoke/particulates. The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke. The high methane content of the gas stream routed to the completion combustion device, it suggests that there should not be smoke except in specific circumstances (*e.g.,* energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke.

The previous BSER analyses cost effectiveness per ton of methane and VOC emissions reduced per completion event evaluated for REC, completion combustion, and REC and completion combustion were updated to 2019 dollars. The results of this updated analysis are provided below, and details are provided in the NSPS OOOOb and EG TSD for this rulemaking.

The updated capital cost for performing a REC for a well completion or recompletion lasting 3 days is estimated to be $15,174 (2019 dollars). Monetary savings associated with additional gas captured to the sales line is estimated based on a natural gas price of $3.13 per Mcf. It was assumed that all gas captured would be included as sales gas. The updated capital and cost for wells including completion combustion devices resulted in an estimated average completion combustion device cost of approximately of $4,198 per well completion (2019 dollars). For both REC and completion combustion devices, the capital costs are one-time events, and annual costs were conservatively assumed to be equal to the capital costs. The EPA also evaluated the costs that would be associated with using a combination of a REC and completion combustion device. The annual costs would be a combined estimated capital and annual cost of $19,371 (2019 dollars). As a result of updating capital/annual costs to reflect 2019 dollars and decreasing the control efficiency assumed for completion combustion from 95 percent to 90 percent, the cost effectiveness estimates are slightly higher, but substantially similar to previous cost effectiveness BSER analysis control option estimates for natural gas well and oil well completions and recompletions.

For gas wells, under the single pollutant approach where all the costs are assigned to the reduction of methane emissions and zero to reduction of VOC, the cost effectiveness estimates were approximately $1,180 per ton of methane reduced for REC ($990 with natural gas savings), $330 for completion combustion, and $1,420 for a combination of REC and completion combustion ($1,250 with natural gas savings). If all costs were assigned to VOC reduction and zero to methane reduction, the cost effectiveness estimates were approximately $4,230 per ton of VOC removed for REC ($3,570 with natural gas savings), $1,170 for completion combustion, and $5,110 for a combination of REC and completion combustion ($4,490 with natural gas savings). Under the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, these estimates are approximately $590 per ton of methane reduced for REC ($500 with natural gas savings), $160 for completion combustion, and $710 for a combination of REC and completion combustion ($630 with natural gas savings). For VOC, the cost effectiveness

[300] Memorandum to Bruce Moore, U.S. EPA from ICF Consulting. *Percent of Emissions Recovered by Reduced Emission Completions.* May 2011.

[301] 77 FR 48889–48890, March 22, 2013 (Approval and Promulgation of Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nation), North Dakota; Rule).

estimates were approximately $2,100 per ton of VOC removed for REC ($1,790 with natural gas savings), $590 for completion combustion, and $2,600 for a combination of REC and completion combustion ($2,250 with natural gas savings).

For oil wells, under the single pollutant approach where all the costs are assigned to the reduction of methane emissions and zero to reduction of VOC emissions, the cost effectiveness values were approximately $1,620 per ton of methane reduced for REC ($1,440 with natural gas savings), $450 for completion combustion, and $1,960 for a combination of REC and completion combustion ($1,790 with natural gas savings). Where all costs were assigned to reducing VOC emissions and zero to reducing methane emissions, the cost effectiveness estimates were approximately $5,840 per ton of VOC removed for REC ($5,190 with natural gas savings), $1,620 for completion combustion, and $7,070 for a combination of REC and completion combustion ($6,450 with natural gas savings). Under the multipollutant approach where half the cost of control is assigned to the methane reduction and half to the VOC reduction, these estimates are approximately $810 per ton of methane reduced for REC ($720 with natural gas savings), $230 for completion combustion, and approximately $980 for a combination of REC and completion combustion ($900 with natural gas savings). For VOC, the cost effectiveness estimates were approximately $2,920 per ton of VOC removed for REC ($2,600 with natural gas savings), $810 for completion combustion, and $3,530 for a combination of REC and completion combustion ($3,220 with natural gas savings).

As noted above, the current NSPS OOOOa requirements consist of a combination of REC and completion combustion for hydraulically fractured natural gas and oil well completions. These techniques have been employed by the oil and gas industry since 2012 for natural gas well completions and 2016 for oil well completions. The EPA concludes that the cost effectiveness of REC, completion combustion, or a combination, for natural gas and oil wells are within the range that the EPA considers to be reasonable when considering both methane and VOC cost effectiveness. Since there are multiple scenarios where the cost effectiveness of the control measures is reasonable for natural gas and oil wells (including the cost effectiveness of VOC for REC and combined REC and completion combustion), we conclude that the overall cost effectiveness is reasonable.

There are secondary impacts from the use of a completion combustion device, as the combustion of the gas creates secondary emissions of hydrocarbons, NO_X, CO_2, and CO. The EPA considers the magnitude of these emissions to be reasonable given the significant reduction in methane and VOC emissions that the control would achieve. Details of these impacts are provided in the NSPS OOOOb and EG TSD for this rulemaking. There are no other wastes created or wastewater generated from either REC or completion combustion.

In light of the above, we determined that the current standards, which consist of a combination of REC and combustion, continue to represent the BSER for reducing methane and VOC emissions from well completions of hydraulically fractured or refractured oil and natural gas wells. We therefore propose to retain these standards in the proposed NSPS OOOOb.

As discussed in section XII.I.1.c, in the 2020 Technical Rule, the EPA made certain amendments to the VOC standards for well completions in the 2016 NSPS OOOOa. For the same reasons provided in the 2020 Technical Rule and discussed in section X.B.1 of this preamble for including these amendments for methane in NSPS OOOOa, the EPA is proposing to include these methane and VOC amendments for well completions in the NSPS OOOOb rule.

2. EG OOOOc

A well completion operation following hydraulic fracturing or refracturing is a ''modification,'' as defined in CAA section 111(a), as each such well completion operation involves a physical change to a well that results in an increase in emissions; accordingly, each such operation would trigger the applicability of the NSPS. Therefore, there are no ''existing'' well completion operations of hydraulically fractured or refractured oil or natural gas wells. In light of the above, there are no proposed presumptive standards for such operations in this action.

J. Proposed Standards for Oil Wells With Associated Gas

1. NSPS OOOOb

a. Background

Wells in some formations and shale basins are drilled primarily for oil production. Although the wells are drilled for oil, the wells may produce an associated, pressurized natural gas stream. The natural gas is either naturally occurring in a discrete gaseous phase within the liquid hydrocarbon or is released from the liquid hydrocarbons by separation. In many areas, a natural gas gathering infrastructure may be at capacity or unavailable. In such cases, if there is not another beneficial use of the gas at the site (*e.g.,* as fuel) the collected natural gas is either flared or vented directly to the atmosphere.

Emissions from associated gas venting and flaring are not regulated by either the 2012 NSPS OOOO or the NSPS OOOOa. The EPA did not evaluate BSER for associated gas production in either rulemaking. For this rulemaking, the EPA is proposing that methane and VOC emissions resulting from associated gas production be reduced by at least 95 percent.

b. Definition of Affected Facility

The EPA is proposing the definition of an oil well associated gas affected facility as an oil well that produces associated gas.

c. Description

In 2019, according to the EIA, the number of onshore gas producing oil wells in the U.S.[302] was 334,342 and the volume of vented and flared natural gas in 2019 was 523,066 million cubic feet.[303] According to the 2021 GHGI, in 2019 venting of associated gas emitted 42,051 metric tons of CH_4 and 1,291 metric tons of CO_2 and flaring of associated gas emitted 81,797 metric tons of CH_4 and 25,355,892 metric tons of CO_2.

For the 2019 reporting year in GHGRP subpart W, there were a total of 2,500 wells that reported emissions from the venting of associated gas emissions. The total emissions from these wells were just over 33,900 metric tons of methane (848,000 metric tons CO_2e). Over 90 percent of these methane emissions were reported in three basins—Gulf Coast, Williston, and Permian. Examining this information by State shows that almost half of the venting wells and over 64 percent of the methane emissions from the venting of associated gas occurs in Texas. Texas and North Dakota account for almost 90

[302] *https://www.eia.gov/dnav/ng/ng_prod_oilwells_s1_a.htm.* The number of onshore gas producing oil wells was derived from the ''U.S. Natural Gas Number of Oil Wells'' subtracting ''Federal Offshore—Gulf of Mexico'' wells [336,732—2,390 = 334,342 wells].

[303] *https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGV_mmcf_a.htm.* The volume of vented and flared natural gas was derived from ''U.S. Natural Gas Vented and Flared'' subtracting ''Alaska—State Offshore'' and ''California—State Offshore'' and ''Federal Offshore—Gulf of Mexico'' and ''Louisiana—State Offshore'' and ''Texas—State Offshore'' [538,479 − 825 − 0 − 14,461 − 45 − 82 = 523,066].

percent of the reported methane emissions from vented associated gas oil wells. The average methane emissions from the venting of associated gas in 2019 was 13.6 metric tpy per venting well. The average per State ranges from 0.03 tpy per venting well in California to over 340 tpy per venting well in North Dakota.

The 2019 GHGRP subpart W data also show that there were over 38,000 wells reporting that they flared associated gas, with over 21 million metric tons of CO_2 emissions and over 68,000 metric tons of methane emissions. As with the venting emissions, the majority of the wells flaring associated gas (over 93 percent) were in the Gulf Coast, Williston, and Permian basins. Approximately 96 percent of the CO_2 and methane emissions were reported in these three basins. The majority of the wells flaring associated gas (over 72 percent) and emissions (over 87 percent) were from wells in Texas and North Dakota.

d. Control Options

For new and existing sources (oil wells), options to mitigate emissions from associated gas in order of environmental and resource conservation benefit include:

- Capturing the associated gas from the separator and routing into a gas gathering flow line or collection system;
- Beneficially using the associated gas (*e.g.,* onsite use, natural gas liquid processing, electrical power generation, gas to liquid);
- Reinjecting for enhanced oil recovery; and
- Flaring with legally and practicably enforceable limits.

Typically, State oil and gas regulatory agencies (or, on certain public and Tribal lands, the BLM) regulate venting and flaring of associated gas from oil wells to ensure oil and natural gas resources are conserved and utilized in a manner consistent with their respective statutes. State oil and gas regulatory agencies typically encourage, and in some cases require, capture (conservation) over flaring, then flaring over venting. In addition, these State regulators have adopted a variety of approaches for regulating venting and flaring of associated gas from oil wells. Some require technical and economic feasibility analyses for continuing flaring beyond a certain time (*e.g.,* one year). Some require gas capture plans to track and incrementally increase the percentage of gas captured (rather than flared) over prescribed timelines and some of these include provisions to curtail production in the event of not meeting gas capture goals. Many State oil and gas regulations recognize that there are times when gas capture may not be feasible, such as when there is no gas gathering pipeline to tie into, the gas gathering pipeline may be at capacity, or a compressor station or gas processing plant downstream may be off-line, thus closing in the gas gathering pipeline. Venting is allowed by some State and regulatory agencies in certain circumstances such as emergency or upset conditions, during production evaluation, and well purging or productivity tests. In cases where venting is allowed, these rules typically require reporting of the volume of gas flared and vented (and sometimes a gas analysis), while some States combine flaring and venting information together in publicly accessible well data.

Where flares are allowed, these State oil and gas regulations typically do not include monitoring, recordkeeping and reporting on the performance of the flare and would not be recognized as providing legally and practicably enforceable limits for CAA purposes. Some State environmental regulators address associated gas with a regulation stipulating flaring over venting that includes monitoring, recordkeeping and reporting provisions, while others regulate flaring over venting without monitoring requirements.

The EPA is interested in information on, and the feasibility, of options to utilize associated gas in some useful manner in situations where a sales line is not available. In addition to use as fuel, such options could include conversion technologies where methane is converted into hydrogen or other added value chemicals. The EPA is interested in information on these, as well as other, technologies.

e. 2021 BSER Analysis

In performing the BSER analysis for emissions from associated gas oil wells, we recognize there are similarities between the control options available for associated gas and those available for emissions from oil well completions. We are soliciting comment on these similarities. For both flowback emissions during oil well completions and associated gas production, if the infrastructure exists to allow the routing of the gas to a sales line (*e.g.,* ''into a gas flow line or collection system''), owners and operators will almost always choose that option given the economic benefits of being able to sell the gas. For example, in the 2019 GHGRP subpart W data, applicable facilities reported over 1.2 trillion scf of associated gas was routed to sales lines. This represents only a subset of the total volume of associated gas sent to a sales line, as GHGRP subpart W does not require reporting of this volume in subbasins where the company is not also reporting venting or flaring associated gas.

The environmental benefit of routing all associated gas to a sales line is significant, as there are no methane and VOC emissions. The EPA assumes that in situations where gas sales line infrastructure is available, there is minimal cost to owners and operators to route the associated gas to the sales line. While situations at well sites can differ, which would impact this cost, the EPA believes that in every situation the value of the natural gas captured and sold would outweigh these minimal costs of routing the gas to the sales line, thus resulting in overall savings. Given the prevalence of this practice, the environmental benefit, and the economic benefits to owners and operators, the EPA concludes that BSER is routing associated gas from oil wells to a sales line. The EPA seeks comment on this proposed BSER determination, including comment on how to define whether an oil well producing associated gas has access to a sales line for purposes of this BSER and what factors (such as proximity to an existing sales line) should bear on that determination.

NSPS OOOOa also includes other compliance options that achieve a 100 percent reduction in emissions from recovered flowback gas. These are ''re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve.'' 40 CFR 60 60.5375a(a)(1)(ii). The EPA believes that, for associated gas from oil wells, the options of using the gas as an onsite fuel source or for another useful purpose are also viable alternatives to routing to a sales line. However, a significant difference exists between the short-term and relatively small volume of gas recovered during the limited duration of completion flowback versus the consistent flow of recovered gas from ongoing production from the well. Because of this difference, the EPA does not have information that supports re-injecting the associated gas into the well or another well as a viable emissions control alternative. Therefore, the EPA is specifically requesting comment on whether NSPS OOOOb should include re-injecting associated gas as an alternative to routing the gas to a sales line.

The format of the well completion provisions in NSPS OOOOa recognize that routing the recovered gas to a gas flow line or collection system, re-

injecting the recovered gas, or using the recovered gas fuel or for another purpose may not be technically feasible. In these situations, owners and operators are required to route the flowback emissions to a completion combustion device.

Similarly, the EPA recognizes that there are associated gas oil wells where there is no access to a gas sales line. Therefore, as an aspect of BSER in these situations, the EPA evaluated the flaring of the associated gas as an option to control emissions for situations where access to a sales line is not available.

As discussed previously, the average annual methane emissions from the venting of associated gas reported in GHGRP subpart W for 2019 is 13.6 metric tpy (14.9 tpy) per venting well. Using a representative gas composition for the production segment, the estimated VOC emissions would be 4.15 tpy per well. We conducted the BSER analysis using this emissions level as a representative well.

The installation and proper operation of a flare can achieve 95 percent and greater reduction in methane and VOC emissions. To be conservative, a 95 percent emission reduction was used for the BSER analysis. Therefore, the resulting emission reductions are 14.2 tpy methane and 3.9 tpy VOC.

The capital cost of a flare is estimated to be $5,719. This was based on a 2011 Natural Gas Star Pro Fact Sheet and updated to 2019 dollars. The resulting capital recovery, assuming a 7 percent interest rate and 15-year equipment life, was $628. The Natural Gas Star Pro report estimated the cost of the natural gas needed for the pilot was $1,800 per year. For this cost analysis, we assumed that this cost was not warranted since the associated gas could be used to fuel the pilot. We are soliciting comments on this cost estimate.

The EPA stresses that 95 percent or greater emission reduction is achievable if the flare is properly operated and maintained. In order to ensure that this occurs, the EPA proposes to apply the requirements in § 60.18 of the part 60 General Provisions to oil wells flaring associated gas. In order to account for the cost of the compliance with these requirements, we assumed that the associated cost would be 25 percent of the total annual costs, or an additional $160. This results in a total estimated annual cost of $785. We are soliciting comment on the estimated costs associated with compliance with the § 60.18 monitoring, reporting, and recordkeeping costs for flares used to control emissions of vented associated gas emissions, and whether those requirements would ensure the flare is achieving the proposed emission reduction of 95 percent or greater.

Based on these annual costs and the emission reductions cited above, the cost effectiveness, using the single pollutant method, is $55 per ton of methane reduction and $200 per ton of VOC reduction. Using the multipollutant approach, the cost effectiveness is $30 per ton of methane and $100 per ton of VOC. These cost effectiveness values are well within the range considered reasonable by the EPA.

As discussed above, while flares significantly reduce the methane and VOC emissions, there are CO, CO_2, and NO_X emissions resulting from the combustion of the associated gas. We estimate that for the representative well, the annual emissions resulting from the flaring of the associated gas would be 50 tpy CO_2, 0.1 tpy CO, and 0.03 tpy NO_X. While these secondary impacts are not negligible, the EPA notes that emissions from flaring represents over an 80 percent reduction in CO_2e emissions as compared to venting.

Based on our analysis, we find that the BSER for reducing methane and VOC emissions from associated gas venting at well sites is routing of the associated gas from oil wells to a sales line. In the event that access to a sales line is not available, we are proposing that the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least a 95 percent reduction in emissions of methane and VOC.

We are requesting comment on the affected facility definition and the overall format of the proposed requirements. The EPA is proposing that an associated gas oil well affected facility be each oil well that produces associated gas. The EPA is soliciting comments on how to define ''associated gas'' or an ''oil well that produces associated gas.'' The proposed NSPS OOOOb would require that all associated gas be routed to a sales line. In the event that access to a sales line is not available, the proposed NSPS OOOOb would require that the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least a 95 percent reduction in emissions of methane and VOC.

Under this proposal, every oil well that produces associated gas would be an affected facility and therefore, subject to the rule. For those wells where the associated gas is routed to a sales line, the only requirement would be to certify that this is occurring. Wells that use the associated gas as a fuel or for another purpose would be required to document how it is used. If the associated gas is routed to a flare, all of the proposed monitoring, recordkeeping, and reporting requirements would apply.

As an alternative, the EPA is soliciting comments on defining the affected facility as each oil well that produces associated gas and does not route the gas to a sales line. This would significantly reduce the number of affected facilities, although the burden for owners and operators that route the gas to a sales line would be similar. While they would not be required under NSPS OOOOb to maintain documentation that the gas is routed to a sales line, they would still need to maintain documentation to prove that the well was not an affected facility. Under this alternative, the proposed rule would require that the gas be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least a 95 percent reduction in emissions of methane and VOC. The EPA's concern with this alternative is that while we believe that most owners and operators would route the gas to a sales line if there is access, it would not specifically require routing the gas to a sales line. We expect that the cost of a flare, along with the associated monitoring, reporting, and recordkeeping costs, will provide additional incentive for owners and operators to connect to an available sales line. We are requesting comment on how, under this alternative approach, to incentivize owners and operators even more to capture or beneficially use associated gas. The EPA is specifically requesting comment on whether the proposed requirements will incentivize the sale or productive use of captured gas, and if not, other methods that the EPA could use to incentivize or require the sale or productive use instead of flaring.

2. EG OOOOc

The EPA evaluated BSER for the control of methane from existing associated gas oil wells that do not route the gas to a sales line or to a process for another beneficial use (designated facilities) and translated the degree of emission limitation achievable through application of the BSER into a proposed presumptive standard for these facilities that essentially mirrors the proposed NSPS OOOOb.

First, based on the same criteria and reasoning as explained above, the EPA is proposing to define the designated

facilities in the context of those that commenced construction on or before November 15, 2021. Based on information available to the EPA, we did not identify any factors specific to existing sources that would indicate that the EPA should change these definitions as applied to existing sources. As such, for purposes of the emission guidelines, the definition of a designated facility in terms of associated gas oil wells as existing oil wells with associated gas that do not route the gas to a sales line or to a process for another beneficial use.

Next, the EPA finds that the control options evaluated for new sources for NSPS OOOOb are appropriate for consideration in the context of existing sources under the EG OOOOc. The EPA finds no reason to evaluate different, or additional, control measures in the context of existing sources because the EPA is unaware of any control measures, or systems of emission reduction, for the venting of associated gas that could be used for existing sources but not for new sources.

Next, the methane emission reductions expected to be achieved via application of the control measures identified above for new sources are also expected to be achieved by application of the same control measures to existing sources. The EPA finds no reason to believe that these calculations would differ for existing sources as compared to new sources because the EPA believes that the baseline emissions of an uncontrolled source are the same, or very similar, and the efficiency of the control measures are the same, or very similar, compared to the analysis above. This is also true with respect to the costs, non-air environmental impacts, energy impacts, and technical limitations discussed above for the control options identified.

The information presented above regarding the costs related to new sources and the NSPS are also applicable for existing sources. The EPA considers these cost effectiveness values to be reasonable. Since none of the other factors are different for existing sources when compared to the information from discussed above for new sources, the EPA concludes that BSER for existing sources and the proposed presumptive standard for EG OOOOc to be the requirement to route associated gas to a flare or other control device that achieves at least 95 percent control.

Related to control option of flaring with legally and practicably enforceable limits at existing oil wells specifically, enhancing monitoring and performance requirements for flares at existing oil wells may be an important emissions reduction measure. For those operators who have already installed monitoring capability on their existing flares, the additional investment may be minimal to cover reporting of performance. For those existing oil wells where operators do not have flare monitoring installed, the EPA solicits comment both on the flare performance monitoring technology available and the cost of procuring, installing, operating and maintaining such technology. This could include, but is not limited to, digital pilot light monitors, combustion temperature, gas flow meters, gas chromatography (GC) units, and passive remote monitoring of combustion efficiencies at the flare tip. Similar technologies have been used for flares controlling landfill gas, including automated notifications of flare failure. Additional discussion of control devices, including flares, is included in section XIII.D of this preamble.

K. Proposed Standards for Sweetening Units

Sulfur dioxide (SO_2) standards for onshore sweetening units were first promulgated in 1985 and codified in 40 CFR part 60, subpart LLL (NSPS LLL). In 2012, the EPA reviewed the NSPS for the oil and natural gas sector, and the resulting 2012 NSPS OOOO rule incorporated provisions of NSPS LLL with minor revisions to adapt the NSPS LLL language to NSPS OOOO (77 FR 49489). The incorporated provisions required sweetening unit affected facilities to reduce SO_2 emissions via sulfur recovery. The EPA also increased the SO_2 emission reduction standard from the subpart LLL requirement for units with a sulfur production rate of at least 5 long tons per day (LT/D) from 99.8 percent to 99.9 percent. This change was based on the reanalysis of the original data used in the NSPS LLL BSER analysis.

In 2016, the EPA finalized the NSPS OOOOa rule—which established standards for both methane and VOCs for certain equipment, process and activities across the oil and natural gas sector. The final 2016 NSPS OOOOa rule reaffirmed and included the SO_2 emission reduction requirements as specified in the 2012 NSPS OOOO rule (81 FR 35824).

The EPA then amended the 2016 NSPS OOOOa rule in 2020 to correct an affected facility definition applicability error in the rule as it pertains to sweetening units. The 2016 NSPS OOOOa rule erroneously limited the applicability of the SO_2 standards to sweetening units located at onshore natural gas processing plants. This limitation was not included in NSPS LLL, and no reason was identified as to ''why the extraction of natural gas liquids relates in any way to the SO_2 standards such that the standards should only apply to sweetening units located at onshore natural gas processing plants engaged in extraction or fractionation activities'' (85 FR 57398). Therefore, the 2020 NSPS OOOOa final rule amendments corrected the affected facility description applicability error to correctly define affected facilities as any onshore sweetening unit that processes natural gas produced from either onshore or offshore wells at 40 CFR 60.5365a(g).

A sweetening unit refers to a process device that removes H_2S and/or CO_2 from the sour natural gas stream (40 CFR 60.5430a)—*i.e.,* sweetening units convert H_2S in acid gases (*i.e.,* H_2S and CO_2) that are separated from natural gas by a sweetening process, like amine gas treatment, into elemental sulfur in the Claus process. These units can operate anywhere within the production and processing segments of the oil and natural gas source category, including as stand-alone processing facilities that do not extract or fractionate natural gas liquids from field gas (85 FR 57408, September 15, 2020).

An estimated 6,900 tons of SO_2 emissions were reported under the National Emissions Inventory (NEI) for Year 2017 [304] for Source Classification Code 31000201 (Industrial Processes Oil and Gas Production, Natural Gas Production, Gas Sweetening: Amine Process) and SCC 31000208 (Industrial Processes, Oil and Gas Production, Natural Gas Production, Sulfur Recovery Units).

Pursuant to CAA section 111(b)(1)(B), the EPA reviewed the current standards in NSPS OOOOa (including the 2020 revisions) for sweetening units and proposes to determine that they continue to reflect the BSER for reducing SO_2 emissions. The EPA has not identified any greater emissions control level than what is currently required under NSPS OOOOa for sweetening unit affected facilities. Therefore, the EPA is proposing to retain/include the current NSPS OOOOa requirements for sweetening units for the control of SO_2 emissions from sweetening unit affected facilities in NSPS OOOOb. The proposed NSPS OOOOb maintains the requirement that each sweetening unit that processes natural gas produced from either onshore or offshore wells is an affected facility; as well as each sweetening unit

[304] 2017 National Emissions Inventory (NEI) Data | US EPA.

that processes natural gas followed by a sulfur recovery unit. Units with a sulfur production rate of at least 5 long tons per day must reduce SO_2 emissions by 99.9 percent. Compliance with the standard is determined based on initial performance tests and daily reduction efficiency measurements. For affected facilities that have a design capacity less than 2 LT/D of H_2S in the acid gas (expressed as sulfur), recordkeeping and reporting requirements are required; however, emissions control requirements are not required. Facilities that produce acid gas that is entirely re-injected into oil/gas-bearing strata or that is otherwise not released to the atmosphere are also not subject to emissions control requirements.

XIII. Solicitations for Comment on Additional Emission Sources and Definitions

The EPA is considering including additional sources as affected facilities under the proposed NSPS OOOOb and the proposed EG OOOOc. Specifically, the EPA is evaluating the potential for establishing standards applicable to abandoned and unplugged wells, pipeline pigging and related blowdown activities, and tank truck loading operations. While the EPA has assessed these sources based on currently available information, we have determined that we need additional information to evaluate BSER and propose NSPS and EG for these emissions sources. As described below, the EPA is soliciting information to assist in this effort.

The EPA is also assessing whether proposed standards that would require 95 percent reduction based on a combustion control device as the BSER (*e.g.,* standards for storage vessels, centrifugal compressors, pneumatic pumps, and associated gas that cannot be routed to a sales line or consumed for a useful purpose) could be further strengthened, including the potential for additional monitoring and associated recordkeeping and reporting requirements, to ensure proper design and operation of combustion control devices.

While we are not proposing NSPS nor EG for these emissions sources (*i.e.,* abandoned wells, pigging operations, or tank truck loading) or updates to ensure proper design and operation of combustion control devices in this action, the EPA is soliciting comment and information that would better inform the EPA as we continue to evaluate options for these sources. Should the EPA receive information through the public comment process that would help the Agency evaluate BSER for these emission sources, the EPA could consider NSPS and EG for these sources through a supplemental proposal. In this section we summarize the available information that we have evaluated regarding emissions, control options, and where specific States may have existing requirements, and we solicit specific comments. In the case of combustion control devices, we solicit comment on the current standard of 95 percent reduction and what additional monitoring, recordkeeping, and reporting may be appropriate to ensure compliance. We also generally solicit comment and information on the following topics associated with these emission sources.

The EPA solicits comment on the control options discussed below and how these controls may be broadly applied across different basins or geographic areas. The EPA solicits comment on what equipment is onsite during these emission events. The EPA solicits comment on the technical feasibility of control options and any instances where it is not technically feasible to minimize emissions from these sources including, but not limited to, any retrofit concerns for existing sources. The EPA solicits comment on any practices owners and operators already implement as part of voluntary efforts or State requirements to minimize emissions from these sources. The EPA solicits comment on methods/approaches for estimating baseline emissions from these sources, estimating cost of control, and efficiency of control options. Finally, the EPA solicits comment on the cost of maintaining records and submitting reports for these emissions sources, including the types of records that are appropriate to maintain and report.

A. Abandoned Wells

The EPA is soliciting comment for potential NSPS and EG to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged ineffectively. Should the EPA receive information through the public comment process that would help the Agency evaluate BSER, the EPA may propose NSPS and EG through a supplemental proposal.

The EPA broadly characterizes abandoned wells as oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells. This includes wells that State governments classify as idle, inactive, dormant, or shut-in, but not plugged. The classification varies from State to State, and State governments may allow these wells to be dormant, without plugging, for varying time periods that may last several years. It also includes wells with no production for many years—sometimes more than a decade—and no responsible operator. These wells are commonly referred to as orphaned, deserted, or long-term idle. Finally, this includes wells that have been abandoned for long periods, known as legacy wells. State governments have varied definitions of temporarily idled, orphaned, or non-producing wells.

It is the EPA's understanding that since non-producing oil and natural gas wells generally are not staffed and are seldom monitored, many have fallen into disrepair. The EPA recognizes that some States and NGOs also have elevated concerns about the potential number of low-production wells that could be abandoned in the near future as they reach the end of their productive lives. The 2021 GHGI estimates that in 2019 the U.S. population of abandoned wells (including orphaned wells and other non-producing wells) is around 3.4 million (about 2.7 million abandoned oil wells and 0.6 million abandoned natural gas wells).[305] These non-producing wells often have methane, CO_2, and VOC emissions. The most recent studies of emissions from abandoned wells focus on methane emissions, which are larger than the CO_2 or VOC emissions from such wells.[306] The GHGI estimates that abandoned oil wells emitted 209 kt of methane and 4 kt of CO_2 in 2019. While emissions of both pollutants from abandoned oil wells decreased by 10 percent from 1990, the total population of these wells increased 28 percent. The GHGI estimates that abandoned gas wells emitted 55 kt of methane and 2 kt of CO_2 in 2019. While emissions of both pollutants increased from abandoned gas wells by 38 percent from 1990, the total population of such wells increased 84 percent.

The large populations of abandoned unplugged wells are likely due to various circumstances. For instance, some operators declare bankruptcy before wells are plugged, and for many, bonding requirements represent only a fraction of the actual costs to plug the well and restore the well site. Wells are also abandoned or idled when changing oil or natural gas prices make them unprofitable to continue production.

[305] The GHGI separates non-producing oil and gas wells into those that are unplugged and plugged. The abandoned wells identified in the GHGI include those that have been taken out of production temporarily, but can return to production, as well as orphan wells.

[306] See TSD at Docket ID No. EPA–HQ–OAR–2021–0317.

The EPA recognizes that many oil and natural gas producing States require the plugging of non-producing oil and natural gas wells, and subsequent restoration of the well site. However, the large number of abandoned, unplugged wells nationwide suggests that Federal standards may be warranted. Many oil and gas producing States specify the time in which wells may remain in idle status without State approval. At the end of that time, States generally require tests of well integrity before giving approval for additional time in this idle status.

In its 2018 survey of idled and abandoned wells, the IOGCC documented State definitions and requirements for idled wells, as well as the management plans for those wells.[307] There is variation in how States define these idle wells, ranging from no definitions to specific definitions for documented and undocumented orphaned and abandoned wells. Further, there is great variability in the allowance for the length of time a well may remain in idle status with or without approval, with some States limiting that time to a few months while other States allow idled status indefinitely. While some States require strict management plans of idled wells, others do not. Finally, some States provide funds for plugging, remediating, and reclaiming orphan wells, and others do not. These funds are supported by civil penalties, settlements, forfeited bonds, and State appropriations. The IOGCC's survey found that 28 States and Canadian provinces have wells approved to remain in idle status, with most having between 100 and 10,000 approved idle wells. Most States and provinces maintain inventories of documented orphan wells and prioritize orphan wells for plugging according to risk. States and provinces reported from zero to 13,266 documented orphan wells, with about half reporting fewer than 100 orphan wells.

The IOGCC's 2018 survey also collected estimates from some States on the number of undocumented orphan wells, including those for which no permits or other records exist. Most of these wells were drilled before there was any regulatory oversight. Ten States reported no undocumented orphan wells. Nine other States did not provide an estimate. Eleven States provided an estimate ranging from fewer than 10 to 100,000 or more undocumented orphan wells. Most of the States surveyed by the IOGCC had established funds dedicated to plugging orphan wells. Money for these funds comes primarily from taxes, fees, or other assessments on the oil and gas industry.

The EPA has identified the following potential strategies to reduce air emissions from these sources. The first strategy is to employ practices and procedures to ensure proper well closure. Under this strategy, the EPA could focus on well closure requirements aimed at preventing future abandonment of unplugged wells and halt the growth of this unplugged population. Given that all wells eventually reach their end of life, this strategy could be applied to both new and existing wells. Under the NSPS, for example, the EPA could require owners or operators to submit a closure plan describing when and how the well would be closed and to demonstrate whether the owner or operator has the financial capacity to continue to demonstrate compliance with the rules until the well is closed and to carry out any required closure procedures per the rule. This demonstration could require some financial assurance or bonding if the Agency determines the financial capacity of the owner or operator to continue to assure compliance with the rule is in doubt. The EPA also could require reporting any transfer of well ownership, along with a copy of the well closure requirements, to the EPA and/or the applicable State when transferring ownership. The Agency might also consider a requirement to temporarily close the well to the atmosphere with a swedge and valve or packer or other approved method once a well is temporarily abandoned or shut in. As one example, this is a requirement under Colorado law for all wells that are designated as shut in or temporarily abandoned.[308]

The primary purpose of detailing financial capacity as part of a compliance plan, and to potentially require some financial assurance bonding, is to ensure that State governments have adequate resources to plug oil and gas wells when the owner or operator is unwilling or unable to do so. The IOGCC notes that States typically have requirements for both single-well or blanket financial assurance. In the IOGCC's 2018 survey, 35 States reported information on the types of financial assurance accepted in their jurisdictions, with most accepting more than one type. The IOGCC noted that the amounts and criteria for bonding vary considerably among the States. Single-well bond amounts range from $1,500 to $500,000 per well; blanket bonds (covering multiple wells) vary from $7,500 to $30,000,000, the IOGCC said. In some States, bond amounts are based on well depth; in others, bond amounts are based on case-by-case evaluations; and in several, bond amounts may be increased if determined necessary.

That study identified the following types of financial assurance, including cash deposit of a payment given as a guarantee that an obligation will be met, certificate of deposit of a financial instrument certifying that the face amount is on deposit with the issuing bank to be redeemed for cash by the State if required, financial statements of a report of basic accounting data that depicts a firm's financial history and activities, letter of credit, irrevocable letter of credit where payment is guaranteed if stipulated conditions are met, security interest giving the right to take property or a portion of property offered as security, and surety or performance bonds as a contract by which one party agrees to make payment on the default or debt of another party. Other forms of financial assurance include certificates of insurance, consolidated financial funds, escrow accounts, and liens. The amounts and criteria for financial assurance vary considerably among the States and provinces.

Another strategy under consideration is to require fugitive emissions monitoring at a specified frequency for the duration of time the well is idled and unplugged. The EPA's understanding, however, is that most idled and non-producing well sites would be classified as wellhead only sites, which the EPA is proposing to exclude from fugitive emissions monitoring for both new and existing well sites (see section XI.A).

The EPA is aware that other Federal agencies have information on, and experience with, abandoned wells, such as the U.S. Forest Service, National Park Service, U.S. Fish and Wildlife Service, and the BLM. On Federal and Tribal mineral estate, the BLM coordinates with the surface management agency when remediating abandoned wells to mitigate the potential risks those wells may pose. The EPA may be informed by the methods employed by the BLM to monitor and remediate abandoned wells on Federal lands, as well as by draft legislative initiatives that may expand the scope of the BLM's efforts. The EPA understands that one such initiative, the ''Revive Economic Growth and Reclaim Orphaned Wells (REGROW) Act,'' could amend the Energy Policy Act of 2005 to

[307] See IOGCC Report located at Docket ID No. EPA–HQ–OAR–2021–0317.

[308] Code of Colorado Regulations, Oil and Gas Conservation Commission, 2 CCR 404–1, paragraph b, ''Temporary Abandonment,'' p. 80.

require the BLM to establish a new program to plug, remediate, and reclaim orphaned oil and gas wells and surrounding land, and to provide funds to State and Tribal governments for this purpose.[309]

The EPA is soliciting additional information that would support a determination of the BSER to address emissions from abandoned, idled, and non-producing wells. The specific information of interest includes updates to the number of abandoned, orphaned, or temporarily idled wells in the U.S., which could be State-specific or basin-specific; fugitive emission estimates for the wells; and costs of mitigation measures, including effective closure requirements and proper plugging practices, financial assurance mechanisms, and requiring fugitive emissions monitoring while in idled and unplugged status. The EPA is also soliciting information on mechanisms to disincentivize operator delay in permanently abandoning wells and/or transfer of late-life assets to companies that may not be well-positioned to fund proper closure. The EPA also solicits information at the State level, on the length of time that wells remain temporarily idled before they must be inspected by State governments. Further, we are seeking information about what would be included in well closure requirements, including what closure requirements are appropriate and any recordkeeping and reporting associated with those requirements, as well as whether it is appropriate to close the well to the atmosphere once it is designated as shut in or temporarily abandoned. The EPA also solicits information on whether compliance assurance for well closure requirements will necessitate certain forms of financial assurance on the part of well owners and operators. The EPA solicits comment on effective plugging, such as criteria or guidelines are necessary for sufficient plugging and post-plugging follow up monitoring necessary over a certain time period. Finally, the EPA solicits comments on the cost of monitoring idled or abandoned wells or monitoring techniques that might lower the costs of such monitoring.

[309] S. 1076, ''To amend the Energy Policy Act of 2005 to require the Secretary of the Interior to establish a program to plug, remediate, and reclaim orphaned oil and gas wells and surrounding land, to provide funds to State and Tribal governments to plug, remediate, and reclaim orphaned oil and gas wells and surrounding land, and for other purposes,'' 117th Congress, 1st Session, as introduced on April 12, 2021, available at *https://www.congress.gov/117/bills/s1076/BILLS-117s1076is.xml.*

B. Pigging Operations and Related Blowdown Activities

The EPA is soliciting comment for potential NSPS and EG under consideration that include addressing emissions from pipeline pigging and related blowdown activities. Should the EPA receive information through the public comment process that would help the Agency evaluate BSER, the EPA may propose NSPS and EG through a supplemental proposal.

Raw natural gas is transported from production wells to natural gas processing plants through networks of gathering pipelines. After natural gas processing, pipeline networks in the transmission and storage segment transport the gas to downstream customers. Raw natural gas is frequently saturated with hydrocarbons and may contain other components such as water, carbon dioxide, and hydrogen sulfide, especially upstream of the natural gas processing plant. Liquid condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of the gathering pipelines, operators mechanically push these condensates out of the low elevations and down the pipeline by an operation called ''pigging,'' which involves first inserting a device called a pig[310] into a pig launcher upstream of the pipeline segment where condensates have accumulated. The natural gas flowing through the pipeline then pushes the pig through the pipeline, allowing the pig to sweep along the accumulated condensates. The pig is removed from the pipeline segment when it is caught in a pig receiver. Pigging operations are also conducted using ''smart'' pigs that are equipped with sensors to collect data about the pipeline's structural characteristics and integrity for safety and maintenance purposes.

Before a pig can be inserted or removed through the hatch of a pig launcher or a pig receiver, the pipeline gas in the launcher or receiver barrel must be removed. It is common practice to vent the gas directly to the atmosphere where gas capture or control are not used. This gas is under the same pressure as the pipeline and contains methane, ethane, and VOCs including HAP such as benzene, toluene, ethylbenzene, and xylene. Emissions can also result from the volatilization of collected condensate liquid when the pig barrel is depressurized.

[310] Pigs are typically spherical, barrel- or bullet-shaped objects slightly smaller than the diameter of the pipeline.

Pig launchers and receivers can be installed within larger facilities, such as at a compressor station or natural gas processing plant, or can be ''stand-alone'' sites, where the only equipment at a particular location is related to pigging operations. Additionally, sections of pipeline or equipment that are separate from the pig launcher or receiver may need to be evacuated of gas for reasons other than pigging, such as routine maintenance or inspection activities. Emissions from blowdowns can be calculated by accounting for the volume of the section of pipeline or equipment being evacuated, composition of that gas being vented, pressure of the gas vented, frequency of the blowdown activity, and inclusion of emissions from any volatile liquids present in the pipeline section or equipment being vented.

The EPA is aware of some State and local governments have regulations in place that address blowdown activities, including pigging. These include limits on the amount of emissions from pigging operations, required use of add-on controls, and implementation of best management practices.[311] Estimating emissions from pigging operations is fairly straightforward if all variables (*e.g.,* volume, pressure, and composition of gas) are known. However, the wide range of variables, which are applied in different combinations and are dependent on the frequency of blowdown events, can make it challenging to estimate total nationwide emissions from pigging and related blowdown activities. For example, in 2019, six of the eight operators reporting to GHGRP subpart W in the Uinta Basin reported a collective 7,299 blowdown events due to pigging that met the threshold for reporting under GHGRP subpart W, but the attribution of emissions from each individual pigging event is undetermined at this time.[312] Data reported in 2019 under GHGRP subpart W include 472,995 total individual blowdown events from 1,212 facilities for a combined 307,630 metric tons of methane emitted, including 79,746 events at pig launchers or receivers for a combined total of 19,066 metric tons of methane, however, these data only include emissions from blowdown equipment with a unique physical volume greater than 50 cubic feet and occurring at a facility with total emissions greater than 25,000 metric

[311] See TSD located at Docket ID No. EPA–HQ–OAR–2021–0317.

[312] EPA (2020) Greenhouse Gas Reporting Program. U.S. Environmental Protection Agency. Data reported as of September 26, 2020.

tons CO_2 Eq.[313] The EPA is also aware of a single operator in the Marcellus Shale region that operates around 400 pig launchers and receivers which collectively emit approximately 1,335 metric tons of methane annually, but the total annual emissions from each launcher or receiver varies widely, due to variations in the inputs used to calculate emissions from an individual pigging event.[314] The EPA is seeking comment on the availability of nationwide data sets or methodologies to better identify the total inventory of pig launchers and receivers, and, if no such data set or proxy exists, comment on the most defensible method of calculating total emissions from pigging and related blowdown activities.

The EPA has identified the following potential control options that can reduce emissions from pipeline pig launchers and receivers: (1) Reducing the frequency that the pig launcher or receiver must be evacuated of gas; (2) eliminating or reducing the volume of gas vented during blowdowns; (3) using add-on controls that are applied to blowdown emissions; or (4) a combination of these strategies. The EPA has identified the following systems as potential control strategies to evaluate further.

First, pig ball valves are a design alternative to conventional pig launcher and receiver systems that have a smaller sized barrel (or chamber) that launches and receives the pig, thus resulting in reduced emissions from pigging operations. A conventional pig launcher or receiver system can be retrofitted by replacing the conventional launcher and receiver barrels with special ball valves used to insert and remove the pig directly from the main pipeline. By replacing the large volume barrel with the much smaller volume ball valve, the volume of gas vented during each pigging operation can be reduced by as much as 80 to 95 percent, with a corresponding reduction in emissions and other risks associated with pipeline pigging operations. The net cost of a pig ball valve compared to a traditional launcher/receiver should consider not only the cost of the valve and its installation, but also the savings realized from the prevention of large quantities of vented gas and personnel time spent blowing down a larger launcher/receiver. These costs and savings will vary according to site-specific dimensions, gas composition, and pigging frequency. The EPA understands that not every dimension of pipeline and pig launcher or receiver can use a pig ball valve and seeks further comment on specific circumstances where such equipment is appropriate, potential challenges to using a pig ball valve or retrofitting a launcher or receiver to accommodate a pig ball valve, and specific costs of installing or retrofitting a launcher or receiver compared to a conventional full-barrel launcher or receiver.

Second, multi-pig launcher systems are a design alternative to conventional launcher/receiver systems and reduce pigging emissions by reducing the frequency that launchers and receivers must be opened to the atmosphere and vented prior to pig insertion and removal. The launcher barrel is designed to hold multiple spherical pigs, which are each held in place by gates or pins prior to release. Emission reductions are approximately proportional to the reduction in frequency of opening the launcher and receiver hatch. For example, if a pig launcher holds six pigs, which are loaded all at once, the frequency of venting of the pig barrel is reduced to one-sixth of what it would have been if each pig were loaded individually. The EPA understands that multi-pig launchers and receivers are most appropriate for large diameter pipelines where the footprint of the launcher or receiver site is large enough to accommodate such a system. The EPA seeks comment on specific circumstances where such equipment is appropriate, and requests information on emission reductions and specific costs and savings of installing or retrofitting and operating a multi-pig launcher or receiver compared to a conventional single-pig launcher or receiver.

Next, there are several liquids management technologies that focus on reducing emissions from the liquid condensate that is collected during pigging operations. The first technology relates to the design of condensate drains on receiver barrels. Drains can be installed in the bottom of receiver barrels and pig ball valves to ensure that all condensate is drained from the system prior to depressurization. These drains generally route the condensate back into the main pipelines, to onsite storage tanks, or to onsite processes via enclosed piping and can be retrofitted to existing systems. Recovering condensate prevents emissions that would occur when the liquids volatilize during depressurization of the pig receiver. The EPA seeks comment on different configurations of condensate drains, how the recovered condensate is routed and managed, limitations on using this technology, and data showing the amount of condensate recovered and associated emissions prevented.

The second liquids management technology is a pig ramp on a receiver barrel. A pig ramp[315] is a simple device that can be installed inside a receiver barrel to allow liquids trapped in front of the pig to be captured and to allow liquids clinging to the pig itself to drain before the pig is pulled from the chamber. Pig ramps are typically used in conjunction with condensate drains. The pig ramp promotes the flow of liquid through the barrel and into the drain line by elevating the pig on a rack-like apparatus within the receiver barrel, thereby preventing the pig from creating blockages in the receiver. By promoting the flow of liquid to a location within the receiver or pipeline where the liquids can be captured and drained prior to depressurization, pig ramps reduce the amount of condensed VOCs that would otherwise volatilize during depressurization and removal of the pig from the receiver, thereby reducing emissions. The EPA seeks comment on the successful installation and use of pig ramps as well as information on cost, emission reductions, and concerns or challenges that may make the use of pig ramps inappropriate.

The third liquids management technology involves enhanced liquids containment. If recovered condensate cannot be routed back to the pipeline or to controlled storage vessels, covering containers that collect liquids remaining in a receiver barrel after depressurization with a fitted impermeable material will reduce emissions from evaporation. However, whether or not this strategy will ultimately reduce emissions depends on how the recovered condensate is actually managed. The EPA seeks comment on how recovered condensate can be managed to ensure that emissions from the volatilization of the liquids is minimized, thereby achieving emissions reductions.

Lastly, the EPA has identified several additional control options that can be employed to reduce emissions. First, an owner or operator could install ''jumper lines'' that allow routing high pressure systems to lower pressure systems. The depressurization emissions from high pressure launchers and receivers can be reduced by routing the high-pressure gases to a lower pressure system before venting the remaining gases to the atmosphere or to control equipment.

[313] Id.

[314] See Appendix A to the TSD located at Docket ID No. EPA–HQ–OAR–2021–0317.

[315] *https://www.mplx.com/content/documents/mplx/markwest/Launcher%20Receiver%20Design%20Detail.pdf.*

Routing to a lower pressure system is achieved with a depressurization line (or jumper line) exiting the top of the barrel, or exiting the top of the pig ball valve, and connecting to nearby low-pressure lines on site. Compressor stations and gas plants have low pressure lines on the site that typically can receive these depressurized gases and recycle them through the process. Similarly, launchers and receivers along high pressure pipelines are occasionally located near low pressure pipelines that can receive depressurized gases exiting the barrel or pig ball valve. The EPA seeks comment on the universe of sites where jumper lines are feasible to install, as well as information on cost, emission reductions, and comment on implementation successes and challenges.

Second, owners and operators can route low-pressure systems into a fuel gas system or VRU. Gases that remain in high pressure barrels after venting to low pressure systems, and gases in low pressure barrels, can be recovered during depressurization by discharging the gases to very low-pressure systems at the site (*e.g.,* 10–15 psig). Two examples of very low-pressure systems at compressor stations are a fuel gas system and a condensate tank VRU. Applying such an approach can reduce the gas pressure in the barrels to the pressure of the very low-pressure system, with a corresponding reduction in depressurization emissions. The feasibility of this option is contingent upon the presence of such equipment already onsite. The EPA seeks comment on the universe of sites where routing gas to low-pressure systems is feasible, as well as information on cost, emission reductions, and comment on implementation successes and challenges.

Third, owners and operators can utilize barrel pump-down systems. In barrel pump-down systems, small fixed or portable compressors are used to pump vapors in the receiver or a launcher barrel back into the main pipeline prior to venting and opening the barrel hatch. In barrel pump-down systems, the inlet of a gas compressor is connected to the receiver or launcher depressurization line, and the compressor discharge is connected into the main pipeline. Vapors exiting the depressurization line are pulled into the compression system and recovered back into the pipeline at system pressure. These control systems can recover greater than 99 percent of the depressurization vapors from pig launchers and receivers. The EPA seeks comment on the universe of sites where barrel pump-down systems are feasible, as well as information on cost, emission reductions, and comment on implementation successes and challenges.

Finally, owners and operators could route depressurization gases to combustion devices to control emissions from pigging operations. Depressurization gases from barrels and pig ball valves can be routed through the depressurization line to onsite combustion devices. Well-designed and operated combustion devices can achieve vapor destruction efficiencies as high as 95 to 98 percent. Combustion devices can be used in conjunction with engineering solutions discussed above that first reduce accumulation of or recover as much natural gas and condensate as possible, before destroying the remaining vapors in the combustion device. An example would be to route high pressure systems to low pressure lines and drain barrel condensate, then route the remaining vapors to a combustion device. The EPA understands that large, high-capacity combustion devices are typically available at compressor stations and processing plants and can be used to control pigging gases while meeting the other flaring needs of the facility. There are also numerous low-capacity combustion devices available for serving remote launcher/receiver sites. The EPA seeks comment on the universe of sites where routing depressurization gases from pigging operations to a combustion device is feasible, as well as information on cost, emission reductions, and comment on implementation successes and challenges.

In addition to those methods already identified above for reducing emissions from pigging and related blowdown activities, the EPA is seeking comment on other existing technologies and work practices to reduce the need for blowdown events or reduce emissions from blowdown events when they occur. The EPA is specifically interested in the costs of such technologies or work practices and any variables impacting cost, the control efficiency of the technology or work practice and variables affecting efficiency, and any technological or logistical limitations to implementing the technology or work practice.

While blowdown emissions due to pigging are the primary area where the EPA seeks comment, the EPA is aware that planned blowdowns occur for many reasons, typically related to maintenance or inspection activities. Planned blowdowns may occur at facilities such as a gas processing plant, compressor station, well pad, or stand-alone pig launcher and receiver station, but may also occur at locations other than these facilities, including along pipelines. Under GHGRP subpart W, blowdown vent stack equipment or event types are grouped into the following seven categories: Facility piping (*i.e.,* piping within the facility boundary), pipeline venting (*i.e.,* physical volumes associated with pipelines vented within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet.[316] The EPA seeks comment on any substantive differences between pigging blowdowns and other types of planned blowdowns. Further, the EPA is soliciting comment on how to define an affected facility that includes these blowdown activities, and specific limitations (*e.g.,* technical or logistical) to including non-pigging-related types of blowdowns as part of affected facilities. In particular, the EPA is considering whether the pipeline itself could be defined as an affected facility for purposes of regulating blowdowns. In this scenario, the owner or operator of the pipeline would be responsible for complying with any requirements in place for blowdown activities that occur anywhere along the pipeline. The EPA is soliciting comment on any potential concerns this type of approach would raise for owners and operators, particularly where pipelines cross State boundaries or at the location where pipeline ownership may change from the upstream owner to a different downstream owner.

C. Tank Truck Loading

The EPA is considering including emission standards and EG for tank truck loading operations; however, additional information is needed to evaluate BSER and propose NSPS or EG for this emissions source. The EPA is therefore soliciting comment on adding tank truck loading operations as an affected facility in both the NSPS and EG. Depending on the information received through the public comment process, the EPA may propose NSPS and EG for this source through a supplemental proposal. In this section we summarize the available information we have reviewed for this emissions source and potential control options.

Tank truck loading operations result in emissions when organic vapors in empty tank trucks are displaced to the

[316] 40 CFR 98.233(i)(2).

atmosphere as crude oil, condensate, intermediate hydrocarbon liquids, or produced water from storage vessels is loaded into the tank trucks.[317] Tank truck loading emissions are the primary source of evaporative emissions from tank trucks. It is the EPA's understanding that these vapors are a composite of vapors formed in the empty tank truck by evaporation of residual materials from previous loads, vapors transferred to the tank truck in vapor balance systems as materials are being unloaded, and vapors generated in the tank truck as new material is being loaded. Further, the quantity of evaporative losses from loading operations is, therefore, a function of the parameters such as the physical and chemical characteristics of the crude oil, condensate, intermediate hydrocarbon liquids, or produced water; the method of unloading the crude oil, condensate, intermediate hydrocarbon liquids, or produced water from the storage vessel into the tank truck; and the operations to transport the empty tank truck off-site. The composition of evaporative losses includes VOC, methane, and some HAP.

According to the 2017 NEI, VOC emissions from tank truck loading operations were approximately 72,448 tpy, of which over 70,990 tpy were emitted in the crude oil and natural gas production segment, with the balance of approximately 1,457 tpy emitted from the natural gas processing segment. According to the Oklahoma loading losses guidance, [318] a loading loss vapor VOC content of 85 percent by weight (*i.e.,* 15 percent by weight methane and ethane) may be assumed at wellhead facilities. Condensate and crude oil being loaded at a facility other than a wellhead facility may assume a vapor VOC content of 100 percent. Applying these compositions to the emissions in the 2017 NEI results in approximately 12,528 tpy methane at well sites and 1,457 tpy methane from other segments.

According to EIA, the contiguous continental states area comprising of 48 States have a six year daily average condensate production (API gravity greater than or equal to 50) [319] of 911,000 bbls/day.[320] Emissions per barrel of liquids loaded into tank trucks may be estimated at 0.43lb VOC/bbl. It is the EPA's understanding that most sites use tank trucks with a capacity of approximately 130 bbl. The EPA solicits comment on whether API gravity greater than or equal to 50 is the appropriate gravity of condensate to use.

The EPA understands that there are three options generally in use for controlling emissions during the tank truck loading process. The first control option is vapor balancing which is used to route the vapors displaced during material loading from the tank truck back to the storage vessel. Vapor balancing requires a vapor capture line to connect the tank truck to the storage vessel or manifold system of a tank battery. Because vapor balancing is a closed system, the only anticipated emissions from this control option would be fugitive in nature. However, emissions may occur from the tank truck if it is not properly maintained to DOT specifications, or when the tank truck is cleaned or reloaded without control off-site. Vapor balancing does not have any secondary air impacts or energy requirements. We estimate the capital cost associated with a vapor balancing loading arm (equipment associated with a capture line to connect the tank truck to the storage vessel) at about $5000 per arm based on limited available information.

The second control option is use of a closed vent system operating with a reduction efficiency of 95 to 99 percent. A vapor capture system is used and routed to a vapor recovery device (VRD) or VRU which uses refrigeration, absorption, adsorption, and/or compression. The recovered liquid product is piped back to storage. Alternatively, the vapors may be collected via a vapor capture system and routed to an on-site thermal oxidizer or flare. It is possible to route emissions from this closed vent system to an existing control device located on-site for another purpose. The EPA recognizes that this option may have secondary impacts dependent on the type of control chosen (*e.g.,* VRU, VRD, or combustion device).

Finally, the third option is to directly pipe liquids downstream. By directly piping liquids downstream, no emissions from tank truck loading are released to the atmosphere. We are not aware of any secondary impacts or energy costs associated with this option. However, the EPA is also unsure if this option is technically feasible for every site. It is our understanding that this option requires access to pipelines that can transport the crude oil and/or condensate to downstream locations, and availability of pipelines or capacity to move these liquids in existing pipelines may present an issue with requiring this option for all sites.

In addition to these three control options, the EPA has also identified work practices related to the method of loading which are important and play a role in minimizing air emissions. Practices such as submerged fill and bottom loading help reduce emissions when the fill pipe opening is below the liquid surface level which reduces liquid turbulence and results in much lower vapor generation than encountered during splash (top) loading. We estimate the capital costs of submerged fill loading arms are approximately $1,500 per arm based on limited available data at this time.

The EPA is soliciting comment on the three control options and work practices presented in this section to control or reduce emissions resulting from the tank truck loading process. We solicit comment on other control options or other work practice standards similar to those used in other sectors such as petroleum refineries and how appropriate those options may be for the Crude Oil and Natural Gas source category. We solicit comment on how widely used the control measure and work practices are, any feasibility challenges, and estimates of baseline emissions and cost information associated with these control options and work practices. The EPA is aware of several State regulations that have established standards for this emissions source.[321] Finally, the EPA solicits comment on any practices owners and operators already implement as part of voluntary efforts or State requirements to minimize emissions from these sources.

D. Control Device Efficiency and Operation

As discussed above in sections XI.B, F, and G and XII.B, F, and G, the EPA is proposing to retain the 95 percent reduction performance standard for storage vessels, wet seal centrifugal compressors, and pneumatic pumps based on our analysis showing that a combustion control device remains the BSER for these affected facilities and can reliably achieve this performance standard. This 95 percent reduction is generally achieved by capturing the emissions in a closed vent system that routes those emission to either a control device or back to the process. Under the 2016 NSPS OOOOa, as amended by the 2020 Technical Rule with further

[317] Section 5.2.2.1.1 of the AP–42 Section 5.2: Transportation and Marketing of Petroleum Liquids *https://www.epa.gov/sites/default/files/2020-09/documents/5.2_transportation_and_marketing_of_petroleum_liquids.pdf.*

[318] See *https://www.deq.ok.gov/wp-content/uploads/deqmainresources/LoadingLossesGuidance_08-2019.pdf.*

[319] See *https://glossary.oilfield.slb.com/en/terms/c/condensate.*

[320] See *http://www.eia.gov/dnav/pet/pet_crd_api_adc_mbblpd_m.htm* and TSD located at Docket ID No. EPA–OAR–HQ–2021–0317.

[321] See TSD located at Docket ID No. EPA–OAR–HQ–2021–0317.

amendments proposed in this action, closed vent systems must be designed and operated with no detectable emissions, which is defined as either no emissions detected greater than 500 ppm above background with EPA Method 21, no emissions detected with OGI, or no audible, visual, or olfactory emissions detected. Thus, for a closed vent system, the assumed control efficiency is 100 percent. Therefore, any control device used must be designed and operated to achieve at least 95 percent reduction of emissions to comply with the standard. Examples of control devices include flares, thermal oxidizers, catalytic oxidizers, enclosed combustion devices, carbon adsorption systems, condensers, and VRUs. However, there are various data sources available that suggest combustion control devices, which we have again identified as the BSER for these affected facilities, can achieve a continuous destruction efficiency of 98 percent.[322]

Therefore, the EPA is soliciting comment on potentially proposing a change in the standards for wet seal centrifugal compressors, storage vessels, and pneumatic pumps that would require 98 percent reduction of methane and VOC emissions from these affected facilities. It is the EPA's understanding that combustion control devices, such as flares and enclosed combustion devices, may achieve at least 98 percent control of all organic compounds. Further, as noted in AP–42 Chapter 13.5, properly operated flares achieve at least 98 percent destruction efficiency in the flare plume in normal operating conditions.[323] However, the EPA has received some data[324] relevant to the use of these controls at oil and gas facilities that indicates air-assisted and steam-assisted flares have been found operating outside of the conditions necessary to achieve at least 98 percent control efficiency on a continuous basis. Therefore, the EPA is soliciting comment and information that would help us better understand the cost, feasibility, and emission reduction benefits associated with establishing a 98 percent control efficiency requirement for flares in the Crude Oil and Natural Gas source category, including information on the level of performance being achieved in practice by flares in the field, what conditions or factors contribute to malfunctions or poor performance at these flares, and what measures the EPA could or should require in order to ensure that flares perform at a 98 percent level of control.

The EPA also requests comment on whether additional measures to ensure proper performance of flares would be appropriate to ensure that flares meet the current 95 percent control requirement. For example, the EPA is soliciting comment on the specific requirements that could be used to demonstrate continuous compliance when using a combustion control device. In its July 8, 2021, report, the Office of Inspector General (OIG)[325] observed that State permitting authorities had difficulty verifying continuous compliance with combustion efficiency requirements for flares and enclosed combustors. The OIG recommended that the EPA explore additional means to verify continuous compliance in NSPS OOOO and NSPS OOOOa that would provide additional tools for State agencies to properly permit and enforce combustion efficiency. In considering this recommendation, the EPA has determined that additional information is necessary to support the development of cost-effective continuous compliance requirements.

The current standards in NSPS OOOO and NSPS OOOOa require owners and operators to perform an initial demonstration of compliance for all control devices used to meet the standards in the rule. Further, NSPS OOOO and NSPS OOOOa require monthly EPA Method 22 observations to demonstrate continuous compliance with visible emission requirements, in addition to monitoring for the presence of a pilot light. When an enclosed combustion device is used, owners and operators may demonstrate initial compliance through field testing or through manufacturer testing. The EPA maintains a list of devices for which manufacturers have demonstrated compliance with the testing requirements, including achieving a destruction efficiency of at least 95 percent. The devices that have demonstrated compliance through manufacturer testing have achieved greater than 98 percent destruction efficiency; however, this is demonstrated in a testing environment only, and while the testing is designed to challenge the units, the units may not necessarily demonstrate the same destruction efficiency in field applications. The EPA is seeking comment on alternative means to demonstrate continuous compliance with the required control efficiency (whether maintained at 95 percent or increased to 98 percent).

The Petroleum Refinery Sector Standards, 40 CFR part 63, subpart CC, were amended in 2015 (80 FR 75178) to include a series of additional monitoring requirements that ensure flares achieve the required 98 percent control of organic compounds. Previously these flares had been subject to the flare requirements at 40 CFR 60.18 in the part 60 General Provisions. More recently, the updated flare requirements in NESHAP subpart CC have been applied to other source categories in the petrochemical industry, such as ethylene production facilities (40 CFR part 63, subpart YY), to ensure that flares in that source category also achieve the required 98 percent control of organic compounds. These monitoring requirements include continuous monitoring of waste gas flow, composition and/or net heating value of the vent gases being combusted in the flare, assist gas flow, and supplemental gas flow. The data from these monitored parameters are used to ensure the net heat value in the combustion zone is sufficient to achieve good combustion. The monitoring also includes prescriptive requirements for monitoring pilot flames, visible emissions, and maximum permitted velocity. Lastly, where fairly uniform, consistent waste gas compositions are sent to a flare, owners or operators can simplify the monitoring by taking grab samples in lieu of continuously monitoring waste gas composition, and in some instances, engineering calculations can be used to determine flow measurements.

While effective, the EPA seeks comment on how appropriate any such monitoring requirements and systems would be for the oil and gas production, gathering and boosting, gas processing, or transmission and storage segments subject to the proposed NSPS OOOOb and EG OOOOc. The EPA seeks comment on how to distinguish among flare units where such monitoring is practical, and alternatives where such systems are not practical because they

[322] *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards;* EPA–HQ–OAR–2010–0505–7631, pp. 19–20.

[323] *https://www.epa.gov/sites/default/files/2020-10/documents/13.5_industrial_flares.pdf.*

[324] ''Intermittency of Large Methane Emitters in the Permian Basin'' Daniel H. Cusworth, et al. Environmental Science & Technology Letters 2021 8 (7), 567–573 DOI: 10.1021/acs.estlett.1c00173; and Irakulis-Loitxate, I., Guanter, L., Liu, Y.N., Varon, D.J., Maasakkers, J.D., Zhang, Y., Lyon, D., . . . & Jacob, D. J. (2021). Satellite-based characterization of methane point sources in the Permian Basin (No. EGU21–15877). Copernicus Meetings.

[325] EPA Office of Inspector General Report ''EPA Should Conduct More Oversight of Synthetic-Minor-Source Permitting to Assure Permits Adhere to EPA Guidance,'' Report No. 21–P–0175 July 8, 2021.

lack continuous, on-site personnel or do not have the supporting infrastructure.

Additionally, the EPA seeks comment on several facets of ongoing compliance, including: (1) Owner or operator experience in determining the proper location of a thermocouple for monitoring the presence of a pilot flame, and how to avoid pilot flame failure; (2) how OGI may be used to identify poor combustion efficiency (*e.g.,* to effectively utilize OGI to qualitatively screen enclosed combustion devices) for additional quantitative testing. As noted in Section XI.A.1 of this preamble, we are proposing that emissions resulting from control devices operating in a manner that is not in full compliance with any Federal rule, State rule, or permit, are also considered fugitive emissions. However, there may be other ways to use OGI beyond seeing these fugitive emissions to determine whether control devices are operating properly. For instance, the EPA is interested in how OGI has been used to evaluate heat signature of gases exiting the top of the stack and/or the presence of any unburned hydrocarbon trailing or advective plumes.

With respect to enclosed combustors, the EPA is seeking information on the development of comprehensive specifications for creating an operating envelope under which a make/model can achieve 98 percent reduction (*i.e.,* parameters that should be identified on enclosed combustion device specification sheets), such as maximum heat load, minimum heat load, minimum inlet pressure of waste gas stream, temperature of combustion zone (and proper location for temperature monitor), air intake rate, operation and maintenance necessary for optimal combustion. The EPA also seeks information on real-time monitoring of enclosed combustion device inlet waste gas stream pressure aimed at achieving higher combustion efficiency.

The EPA is also soliciting comment on the current use of non-combustion control devices, the practicality of requiring 98 percent reduction through the use of non-combustion control devices, and the monitoring requirements necessary to demonstrate initial and continuous compliance with such control efficiency. NSPS OOOO and NSPS OOOOa require parametric monitoring for condensers, carbon adsorption systems, and similar control devices, to demonstrate continuous compliance. However, the EPA is seeking comment on whether those monitoring requirements are sufficient to assure continuous compliance should the EPA propose a requirement of 98 percent reduction. In addition to monitoring requirements, the EPA is seeking information on what additional records should be maintained and/or reported for demonstrating continuous compliance when non-combustion control devices are used. The EPA is particularly concerned that increasing the level of control from 95 to 98 percent would disincentivize use or potentially force replacement of non-combustion control devices entirely, including those that capture product for reuse in vapor recovery systems. For example, Texas requires additional monitoring and other significant engineering upgrades for a VRU operator to meet a higher control efficiency than 95 percent.[326] Adding to this concern is the potential increase in overall costs of the rule and potential increase in emissions where facilities replace non-combustion control devices with combustion control devices.

Finally, the EPA is seeking comment on new technologies that would address control efficiency from flares specifically and provide real-time or near real-time measurement of control efficiency. One example would be OGI continuous flame imaging systems that capture flame size and temperature to ensure these parameters are within acceptable ranges. New optical technology is in the early phases of development and deployment. The EPA acknowledges that it may be challenging to analyze costs and reductions without comprehensive data specific to a particular technology, but in the interest of a forward-looking standard, we seek information on potential methods to assure continuous compliance for these control devices.

E. Definition of Hydraulic Fracturing

During pre-proposal outreach, a number of small businesses stated that the NSPS has unintentionally been applied to conventional and vertical wells that engage in hydraulic fracturing. The small business stakeholders contended that these wells have a very different profile from unconventional or horizontal wells in terms of footprint, water usage, chemical usage, equipment used, and flowback period. They recommended that the EPA explicitly exempt these wells from the proposal. We maintain that the original intent of the NSPS was to regulate hydraulically fractured wells, in both conventional and unconventional reservoirs,[327] and both vertical and horizontal wells.[328]

NSPS OOOOa defines hydraulic fracturing as ''the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.'' The NSPS does not offer numeric thresholds that define ''tight formations'' or ''high rate, extended flowback''. When developing the original NSPS OOOO, EPA's analysis assumed hydraulic fracturing is performed in tight sand, shale, and coalbed methane formations which have an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy.[329] The EPA also assumed the flowback lasted between 3 and 10 days for the average gas well,[330] and 3 days for the average oil well.[331] However, in response to a public comment on the 2015 NSPS OOOOa proposal claiming the definition of hydraulic fracturing was too broad, the EPA clarified it intended to ''include operations that would increase the flow of hydrocarbons to the wellhead''.[332] Similarly, in response to a public comment seeking an exemption for wells that have a flowback period of less than 24 hours, the EPA acknowledged that there is a range of flowback periods, finding that the requested exemption was not warranted.[333]

We are soliciting comment on if numeric thresholds for ''tight formations'' or ''high rate, extended flowback'' are appropriate to include in the definition of hydraulic fracturing, and if so, what those numeric thresholds should be. Alternatively, we solicit comment on if it is appropriate to align the NSPS definition with the U.S. Geologic Survey (USGS) definition of hydraulic fracturing (''the process of injecting water, sand, and/or chemicals into a well to break up underground bedrock to free up oil or gas

[326] See *Vapor Recovery Unit Capture/Control Guidance* located at *https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/vapor-rec-unit.pdf.*

[327] See Docket ID Item Nos. EPA–HQ–OAR–2010–0505–0445, Chapter 4, p. 4–2 and EPA–HQ–OAR–2010–0505–4546, p. 30.

[328] See Docket ID Item No. EPA–HQ–OAR–2010–0505–4546, p. 61.

[329] See Docket ID Item No. EPA–HQ–OAR–2010–0505–0445, Chapter 4, p. 4–2.

[330] See Docket ID Item No. EPA–HQ–OAR–2010–0505–0445, Chapter 4, p. 4–1.

[331] See Docket ID Item No. EPA–HQ–OAR–2010–0505–5021, p.20.

[332] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7632, Chapter 3, p. 3–113.

[333] See Docket ID Item No. EPA–HQ–OAR–2010–0505–7632, Chapter 3, p. 3–64.

reserves''),[334] which may more accurately capture the EPA's original intent.

XIV. State, Tribal, and Federal Plan Development for Existing Sources

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (*i.e.,* sulfuric acid plants (acid mist), phosphate fertilizer plants (fluorides), primary aluminum plants (fluorides), kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).[335] In addition, the agency has regulated additional pollutants under CAA section 111(d) in conjunction with CAA section 129.[336] The Agency has not previously addressed emissions of GHGs (in the form of limitations of methane) from the Crude Oil and Natural Gas source category under CAA section 111(d). However, the EPA has ample experience with this source category from implementing the NSPS for so long, and has examined existing sources in a variety of context including the 2013 Federal Implementation Plan (FIP) for oil and natural gas well production facilities on the Fort Berthold Indian Reservation (78 FR 17836 (Mar. 22, 2013)), the 2016 Oil and Natural Gas Control Techniques Guidelines (81 FR 74798 (Oct. 27, 2016)), and the 2020 proposed FIP for managing emissions from oil and natural gas sources on Indian country lands within the Uintah and Ouray Indian Reservation (85 FR 3492 (Jan. 21, 2020)). The draft EG contained in this proposal draw from, among other sources of information and analysis, all of these experiences combined with information on State laws that regulate existing sources. In this action, the EPA is proposing EG for Sates to follow in developing their plans to reduce emissions of GHGs (in the form of limitations on methane) from designated facilities within the Crude Oil and Natural Gas source category.

A. Overview

While section IV of this preamble provides a general overview of the State planning process triggered by the EPA's finalization of EG under CAA section 111(d), this section explains the EG process and proposed State plan requirements in more detail, and also solicits comment on various issues related to this EG. The EG process is governed by CAA section 111(d) as well as the final EG and the EPA's implementing regulations at 40 CFR part 60, subpart Ba.[337] After the EPA establishes the BSER in the final EG, as described in preamble sections XI and XII, each State that includes a designated facility must develop, adopt, and submit to the EPA its State plan under CAA section 111(d). The EPA then must determine whether to approve or disapprove the plan. If a State does not submit a plan, or if the EPA does not approve a State's plan, then the EPA must establish a Federal plan for the State.

Each of these steps, and more, is discussed in detail in this section which is organized into six parts. First, we discuss the components of the EG. Second, we discuss establishing standards of performance in State plans in response to a finalized EG. Third, we discuss the components of an approvable State plan submission. Fourth, we discuss the timing for State plan submissions and compliance times. Fifth, we discuss the EPA's action on State plans and promulgation of a Federal plan, if needed. Sixth, we discuss the CAA section 111(d) process as it relates to Tribes. While this section describes the requirements of the implementing regulations under 40 CFR part 60, subpart Ba, proposes requirements for States in the context of this EG, and solicits comments in the context of this EG, nothing in this proposal is intended to reopen the implementing regulations themselves for comment.

B. Components of EG

As previously described, CAA sections 111(d)(1) and 111(a)(1) collectively establish and define certain roles and responsibilities for the EPA and the States. The EPA addresses its responsibilities by drafting and publishing EG in accordance with 40 CFR 60.22a, which ''[contain] information pertinent to control of the designated pollutant from designated facilities.'' Mirroring language included in CAA section 111(d)(1), the EPA's implementing regulations define a designated pollutant as ''any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.'' 40 CFR 60.21a(a). The EPA's implementing regulations also define a designated facility as ''any existing facility (see § 60.2) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility (see § 60.2).'' *Id.* at § 60.21a(b). The designated pollutant for purposes of the draft EG included in this proposal is GHGs, but the presumptive standards in the EG are expressed in terms of limitations on methane. A description of each of the designated facilities included in the draft EG can be found above in preamble sections XI and XII.

More specifically, 40 CFR 60.22a(b) lists six components to be included in EG to provide information for development of the State plans triggered by the promulgation of the EG. First, EG must include information regarding the ''endangerment of public health or welfare caused, or contributed to, by the designated pollutant.'' 40 CFR 60.22a(b)(1). Information on the harmful public health and welfare impacts of methane emissions from the oil and natural gas industry are included above in section III of this document. Second, the EG must include a ''description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.'' 40 CFR 60.22a(b)(2). The EPA has included such a description above in sections XI and XII of this preamble, and the NSPS OOOOb and EG TSD located at Docket ID No. EPA–HQ–OAR–2021–0317.

[334] USGS. Hydraulic Fracturing. *https://www.usgs.gov/mission-areas/water-resources/science/hydraulic-fracturing?qt-science_center_objects=0#qt-science_center_objects.* Accessed September 1, 2021.

[335] See "Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (March 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (October 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (April 17, 1980); ''EG and Compliance Times for Municipal Solid Waste Landfills,'' 81 FR 59276 (August 29, 2016). In addition, EPA regulated mercury from coal-fired electric power plants in a 2005 rule that was vacated by the D.C. Circuit, ''Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Final Rule,'' 70 FR 28606 (May 18, 2005) (Clean Air Mercury Rule), vacated by *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). EPA also regulated GHG from fossil fuel-fired electric power plants in a 2015 rule that EPA subsequently repealed and replaced with a 2019 rule that, in turn, was vacated by the D.C. Circuit. ''Carbon Pollution EG for Existing Stationary Sources: Electric Utility Generating Units; Final Rule,'' 80 FR 64662 (Oct. 23, 2015) (Clean Power Plan), repealed and replaced by ''Repeal of the Clean Power Plan; EG for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to EG Implementing Regulations,'' 84 FR 32520 (July 8, 2019) (Affordable Clean Energy Rule), vacated by *Am. Lung Assoc.*

[336] See, *e.g.,* ''Standards of Performance for New Stationary Sources and EG for Existing Sources: Sewage Sludge Incineration Units, Final Rule,'' 76 FR 15372 (March 21, 2011).

[337] As previously noted, the D.C. Circuit has vacated certain timing provisions within subpart Ba. *Am. Lung Assoc.* v. *EPA.* However, the court did not vacate the applicability provision, and therefore Subpart Ba applies to any EG that EPA finalizes from this proposal.

Third, the EG must include information regarding ''the degree of emission limitation'' achievable through application of each system, along with information ''on the costs, non-air quality health environmental effects, and energy requirements of applying each system to designated facilities.'' 40 CFR 60.22a(b)(3). The EPA has included such a description in sections XI and XII of this preamble, and the NSPS OOOOb and EG TSD located at Docket ID No. EPA–HQ–OAR–2021–0317. Fourth, the EG must include information regarding the amount of time that the EPA believes would be normally necessary for designated facilities to design, install, and startup the control systems identified in component number three. See 40 CFR 60.22a(b)(4). The EPA explains how it proposes to address this component below in section XIV.E. Fifth, and likely most helpful to States when developing their plans in response to the final EG, the EG must include information regarding the ''degree of emission limitation achievable through the application of the best system of emission reduction'' that has been adequately demonstrated, taking into account the same factors as described in component three (cost, non-air quality health and environmental impact and energy requirements), ''and the time within which compliance with standards of performance can be achieved.'' 40 CFR 60.22a(b)(5). The EPA has included such information in sections XI and XII of this preamble and the NSPS OOOOb and EG TSD located at Docket ID No. EPA–HQ–OAR–2021–0317 as well as in section XIV.E of this preamble. In identifying the degree of achievable emission limitation, the EPA may subcategorize, that is to ''specify different degrees of emission limitation or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.'' *Id.* The EPA can choose to exercise that discretion to subcategorize within the draft EG for certain emission points. Sixth, and last, the EG is to include any other information not contemplated by the five other components that the EPA ''determines may contribute to the formulation of State plans.'' This section includes such information and guidance specifically designed to assist States in developing their plans under CAA 111(d) for these draft EG.

C. Establishing Standards of Performance in State Plans

While the EPA has the authority and responsibility to determine the BSER and the degree of limitation achievable through application of the BSER, CAA section 111(d)(1) provides that States shall submit to the EPA plans that establish standards of performance for designated facilities (*i.e.,* existing sources) and provide for implementation and enforcement of such standards. In light of the statutory text, and as reflected in the technical completeness criteria in the EPA's implementing regulations (explained below), State plans implementing the EG should include requirements and detailed information related to two key aspects of implementation: establishing standards of performance for designated facilities and providing measures that implement and enforce such standards.

Establish Standards of Performance for Designated Facilities. As an initial matter, a State must identify existing facilities within its borders that meet the applicability requirements in the final EG and are thereby considered a ''designated facility'' under the EG.[338] Then, States are required to establish standards of performance for the identified designated facilities. There is a fundamental requirement under CAA section 111(d) that a State's standards of performance reflect the degree of emission limitation achievable through the application of the BSER, which derives from the definition of ''standard of performance'' in CAA section 111(a)(1). The statute further requires the EPA to permit States, in applying a standard of performance, to consider a source's remaining useful life and other factors. Accordingly, based on both the mandatory and discretionary aspects of CAA section 111(d), a certain level of process is required of State plans: namely, the standards of performance must reflect the degree of emission limitation achievable through application of the BSER, and if the State chooses, the consideration of remaining useful life and other factors in applying a standard of performance to a designated facility.

For this EG the EPA is proposing to translate the degree of emission limitation achievable through application of the BSER (*i.e.,* level of stringency) into presumptive standards of performance that States may use in the development of State plans for specific emission points. The EPA believes that the presumptive standards of performance included in the EG will provide States with the level of stringency that the EPA would require to approve a State plan. Put another way, the EPA is choosing to format this EG such that if a State chooses to adopt the presumptive standards as the standards of performance in their State plan, then the EPA believes that such plan could be approved as meeting the requirements of CAA section 111(d) and the finalized EG, assuming the plan meets all other applicable requirements. In this way, the presumptive standards included in the EG serve a similar purpose as a model rule because they are intended to assist States in developing their plan submissions by providing the States with a starting point for their standards that are based on general industry parameters and assumptions. The EPA believes that providing these presumptive standards of performance will create a streamlined approach for States in developing plans and for the EPA in evaluating State plans. Of course, the EPA cannot pre-determine the outcome of a future rulemaking process, and inclusion of these presumptive standards in this EG does not impact the rulemaking process associated with the EPA's review of, and action on, a State plan submission. In its review of State plans, the EPA will consider the information in the final EG (including what EPA publishes in the final EG as the presumptive standards), as well as information submitted by the State and the public. The EPA will evaluate the approvability of all plans through individual notice-and-comment rulemaking processes.

As described in sections XI and XII, the EPA is proposing to translate the degree of emission limitation achievable through application of the BSER into presumptive standards for the following designated facilities as shown in Table 20.

[338] In accordance with 40 CFR 60.23a(b), states without any designated facilities are directed to submit to the Administrator a letter of negative declaration certifying that there are no designated facilities, as defined by EPA's emissions guidelines, located within the state. No plan is required for states that do not have any designated facilities.

TABLE 20—SUMMARY OF PROPOSED EG SUBPART OOOOc PRESUMPTIVE NUMERICAL STANDARDS

Designated facility	Proposed presumptive mass-based standards in the draft emissions guidelines for GHGs
Storage Vessels: Tank Battery with PTE of 20 tpy or More of Methane.	95 percent control.
Pneumatic Controllers: Natural Gas Driven that Vent to the Atmosphere.	VOC and methane emission rate of zero.
Wet Seal Centrifugal Compressors	95 percent control.
Pneumatic Pumps: Natural Gas Processing Plants	Zero natural gas emissions from diaphragm and piston pneumatic pumps.
Pneumatic Pumps: Locations Other Than Natural Gas Processing Plants.	95 percent control of diaphragm pneumatic pumps 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.
Associated Gas from Oil Wells	Route associated gas to a sales line. In the event that access to a sales line is not available, the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent control.

For these designated facilities, State plans would generally be expected to establish standards of performance that reflect these numerical presumptive standards, if included in the final EG. Further, for these designated facilities, the EPA is proposing to require that the standards of performance be expressed in the same form as the numerical presumptive standards set forth in Table 20. For example, for storage vessels that are part of a tank battery with a PTE of 20 tpy or more of methane, the EPA is proposing a numerical presumptive standard of 95-percent control. Accordingly, if finalized as proposed, States would be required to submit a plan that includes numerical standards of performance for these designated facilities expressed in the same form as the presumptive standard of 95 percent control. As described in this proposal and the associated supporting materials in the docket, the EPA has extensively and rigorously performed technical analyses in order to determine the appropriate proposed BSER for each set of designated facilities. The form of the numerical expression of the degrees of emission limitation achievable through application of the BSERs, and the associated presumptive standards, are a result of these technical analyses. The EPA believes that requiring States to maintain the same form of numerical standard in their plans will preserve the integrity of the BSERs and avoid analytic issues that are likely to arise if EPA is required to determine whether a different form of numerical standard submitted by a State has the same level of stringency as the final EG. Accordingly, having a uniform form of standard of performance will help streamline the States' development of their plans, as well as the EPA's review of those plans, since there will be fewer variables to evaluate in the development and review of each standard of performance. The EPA solicits comment on its proposal to require State plans to include numerical standards of performance for these designated facilities that are in the same form as the numerical presumptive standards, and whether EPA should additionally allow States to include a different form of numerical standards for these facilities so long as States demonstrate the equivalency of such standards to the level of stringency required under the final EG.

For the following designated facilities, the EPA is proposing to translate the degree of emission limitation achievable through application of the BSER into the presumptive standards shown in Table 21.

TABLE 21—SUMMARY OF PROPOSED EG SUBPART OOOOc PRESUMPTIVE NON–NUMERICAL STANDARDS

Designated facility	Proposed presumptive non-numerical standards in the draft emissions guidelines for GHGs
Fugitive Emissions: Well Sites—>0 to <3 tpy methane	Perform fugitive emissions survey and repair to demonstrate actual site emissions are reflected in calculation.
Fugitive Emissions: Well Sites—≥3 tpy methane	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
(Co-proposal) Fugitive Emissions: Well Sites—≥3 to <8 tpy methane.	Semiannual OGI monitoring following appendix K. (Optional semiannual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
(Co-proposal) Fugitive Emissions: Well Sites—≥8 tpy methane.	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Compressor Stations	Quarterly OGI monitoring following appendix K. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations on Alaska North Slope.	Annual OGI monitoring following appendix K. (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations..	(Optional) Alternative bimonthly screening with advanced measurement technology and annual OGI monitoring following appendix K.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas driven).	Natural gas bleed rate no greater than 6 scfh.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—intermittent natural gas driven).	Monitor and repair through fugitives program.
Reciprocating Compressors	Replace the reciprocating compressor rod packing based on annual monitoring (when measured leak rate exceeds 2 scfm) or route emissions to a process.
Equipment Leaks at Gas Plants	Bimonthly OGI LDAR program (NSPS VVa as optional alternative).

The EPA's implementing regulations at 40 CFR 60.24a(b) require that standards of performance shall either be based on allowable rate or limit of emissions, except when the EPA identifies cases in an EG where it would not be feasible to prescribe or enforce a rate or limit. Put another way, 40 CFR 60.24a(b) permits the EPA to identify cases where it is not feasible for States to prescribe or enforce a numerical standard, and in those cases the EPA can include non-numerical emissions limitations such as design, equipment, work practice, or operational standards, or a combination thereof, in the EG. See also definition of ''standard of performance'' in 40 CFR 60.21a(f). This authority in the context of the EG is akin to the EPA's authority under CAA section 111(h) to prescribe non-numerical standards where the Administrator determines it is not feasible to prescribe or enforce a numerical standard of performance. Where the EPA finalizes EG that authorize design, equipment, work practice, or operational standard, or a combination thereof, the State ''plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such standards, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed'' by the State plan. See 40 CFR 60.24a(b).

For the designated facilities listed in Table 21 the EPA has determined that it is not feasible to prescribe or enforce a numerical standard. As such, for these designated facilities, the EPA is proposing presumptive standards that are comprised of design, equipment, work practice, and/or operational standards. For these designated facilities, States are generally expected to establish the same non-numerical presumptive standards in Table 21. If States do not incorporate the presumptive standards included in the final EG into their State plan, but instead wish to utilize a different design, equipment, work practice, and/or operational standard for any of the designated facilities listed in Table 21, then the EPA is proposing to require that the State include in its plan a demonstration of how that standard will achieve a reduction in methane emissions at least equivalent to the reduction in methane emissions achieved by application of the presumptive standards included in the final EG. Such a demonstration should take into account, among other factors, the timelines for compliance. The EPA believes that this requirement is consistent with the AMEL provision in CAA section 111(h)(3), which requires a demonstration that any alternative ''will achieve a reduction in emissions . . . at least equivalent to the reduction in emissions'' achieved by EPA's standard, and the technical completeness criteria found at 40 CFR 60.27a(g)(3)(iv), which requires that State plans must include a ''demonstration that the State plan submittal is projected to achieve emissions performance under the applicable EG.''

To the extent that a State determines the presumptive standards in the final EG are not reasonable for a particular designated facility due to remaining useful life and other factors, the statute requires that the EPA's regulations under CAA section 111(d) permit States to consider such factors in applying a standard of performance. As such, the EPA's implementing regulations at 40 CFR 60.24a(e) allow States to consider remaining useful life and other factors to apply a less stringent standard of performance to a designated facility or class of facilities if one or more demonstrations are made. These demonstrations include unreasonable cost of control resulting from plant age, location, or basic process design; physical impossibility of installing necessary control equipment; or other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable. The implementing regulations also clarify that, absent such a demonstration, the State's standards of performance must be ''no less stringent than the corresponding'' EG. See 40 CFR 60.24a(c).

The EPA intends to provide further clarification on the general process and requirements for accounting for remaining useful life and other factors, including on the reasonableness aspect of the required demonstration, via a rulemaking to amend the implementing regulations in the near future. However, the EPA also recognizes that the oil and natural gas industry is unique such that the general approach to considering remaining useful life and other factors in the implementing regulations may not be an ideal fit. For example, the sheer number and variety of designated facilities in the oil and natural gas industry could make a source-specific (or even a class-specific) evaluation of remaining useful life and other factors extremely difficult and burdensome for States that want to undertake a demonstration. In addition, the presumptive standards for these designated facilities generally entail fewer major capital expenses compared with other industries for which EPA has previously issued EG under CAA section 111(d), and many of the proposed presumptive standards generally take the form of design, equipment, work practice, or operational standards rather than numerical emission limitations. Further, in proposing the presumptive standards for existing sources, the EPA has deliberately included certain flexibilities (*e.g.,* in cases of technical infeasibility) such that the EPA believes the presumptive standards should be achievable and cost-effective for a wide variety of facilities across the source category. Given these facts, the EPA believes that it would likely be difficult for States to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities. The EPA is soliciting comment on these observations, and any other facts and circumstances that are unique to the oil and natural gas industry that could impact the remaining-useful-life-and-other-factors demonstration. The EPA is also soliciting comment as to whether the Agency should include specific provisions regarding the consideration of remaining useful life and other factors in this EG that would supplement or supersede the general provisions in the implementing regulations.

To the extent a State chooses to submit a plan that includes standards of performance that are more stringent than the requirements of the final EG, States have the authority to do so under CAA section 116, and the EPA has the authority to approve such plans and render them Federally enforceable if all applicable requirements are met. *Union Electric Co.* v. *EPA,* 427 U.S. 246, (1976). See also 40 CFR 60.24a(f). The EPA acknowledges that in the Affordable Clean Energy (ACE) rule, it previously took the position that *Union Electric* does not control the question of whether CAA section 111(d) State plans may be more stringent than Federal requirements. The ACE rule took this position on the basis that *Union Electric* on its face applies only to CAA section 110, and that it is potentially salient that CAA section 111(d) is predicated on specific technologies whereas CAA section 110 gives States broad latitude in the measures used for attaining the National Ambient Air Quality Standards (NAAQS). 84 FR 32559–61 (July 8, 2019). The EPA no longer takes this position. Upon further evaluation, the EPA believes that because of the structural similarities between CAA sections 110 and 111(d), CAA section 116 as interpreted by *Union Electric*

requires the EPA to approve CAA section 111(d) State plans that are more stringent than required by the EG if the plan is otherwise is compliance with all applicable requirements. *See FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009). The D.C. Circuit in *Union Electric* rejected a construction of CAA sections 110 and 116 that measures more stringent than those required to attain the NAAQS cannot be approved into a federally enforceable State Implementation Plan (SIP) but must be adopted and enforced only as a matter of State law. *Id.* at 263–64. While the BSER and the NAAQS are distinct from one another in that the former is technology-based and the latter is based on ambient air quality, both CAA sections 111(d) and 110 are structurally similar in that States must adopt and submit to the EPA plans which include requirements to meet the objectives of each respective section. Requiring States to enact and enforce two sets of standards, one that is a federally approved CAA section 111(d) plan and one that is a stricter State plan, runs directly afoul of the court's holding that there is no basis for interpreting CAA section 116 in such manner. Therefore, the EPA interprets CAA sections 111(d) and 116 as allowing States to include, and the EPA to approve, more stringent standards of performance in State plans. The EPA notes that its authority is constrained to approving measures which comport with applicable statutory and regulatory requirements. For example, CAA section 111(d) only contemplates that State plans include requirements for designated facilities, therefore the EPA believes it does not have the authority to approve and render federally enforceable measures on other entities.

The EPA is also aware that in the context of regulating the oil and natural gas industry many States have existing programs they may want to leverage for purposes of satisfying their CAA section 111(d) State plan obligations. The EPA anticipates providing information on ways in which State plans can accommodate existing State programs to the extent such programs are at least as stringent as the requirement of the final EG. Consistent with the proposed presumptive standards, the EPA proposes that a State plan which relies on an existing State program must still establish standards of performance that are in the same form as the presumptive standards. The EPA solicits comment on whether States relying on existing programs should be authorized to include a different form of standard in their plans so long as they demonstrate the equivalency of such standards to the level of stringency required under the final EG, and how such equivalency demonstrations can be made in a rigorous and consistent way. The EPA proposes to require that, in situations where a State wishes to rely on State programs (statutes and/or regulations) that pre-date finalization of the EG proposed in this document to satisfy the requirements of CAA section 111(d), the State plan should identify which aspects of the existing State programs are being submitted for approval as federally enforceable requirements under the plan, and include a detailed explanation and analysis of how the relied upon existing State programs are at least as stringent as the requirements of the final EG. The EPA notes that the completeness criteria in 40 CFR 60.27a(g) requires a copy of the actual State law/regulation or document submitted for approval and incorporation into the State plan. Put another way, where a State is relying on an existing State program for its plan, a copy of the pre-existing State statute or regulation underpinning the program would be required by this criterion, and would be a critical component of the EPA's evaluation of the approvability of the plan. The EPA also solicits comment on various ways in which existing State programs can be adopted into State plans. Particularly, the EPA is interested in how existing State programs that regulate both designated facilities and sources not considered as designated facilities under this EG could be tailored for a State plan to meet the requirements of CAA section 111(d).

Providing Measures that Implement and Enforce Such Standards. As part of establishing standards of performance, State plans must also include compliance schedules for those standards. See 40 CFR 60.24a(a). Section XIV.E, explains how the EPA is proposing to approach compliance schedules. The EPA's implementing regulations require that, except where the State chooses to account for remaining useful life and other factors, State plans shall require final compliance as expeditiously as practicable, but no later than the compliance times specified in the EG. See 40 CFR 60.24a(c). Where a State applies a less stringent standard of performance because of remaining useful life and other factors, the compliance schedule must appropriately comport with that standard.[339]

In addition to establishing standards of performance and compliance schedules, State plans must also include, adequately document, and demonstrate the methods employed to implement and enforce the standards of performance such that the EPA can review and identify measures that assure transparent and verifiable implementation. As part of ensuring that regulatory obligations appropriately meet statutory requirements such as enforceability, the EPA has historically and consistently required that obligations placed on sources be quantifiable, non-duplicative, permanent, verifiable, and enforceable. See 40 CFR 60.27a(g)(3)(vi). In accordance with the EPA's implementing regulations, standards of performance required for designated facilities as part of a State plan to implement the EG proposed here must be non-duplicative, permanent, verifiable, and enforceable. The EPA acknowledges that it may not be feasible to quantify certain non-numerical standards of performance included in the EG. As such, the EPA is proposing that standards of performance for this EG be quantifiable to the extent feasible. A State plan implementing the EG should include information adequate to support a determination by the EPA that the plan meets these requirements. Additionally, States must include appropriate monitoring, reporting, and recordkeeping requirements to ensure that State plans adequately provide for the implementation and enforcement of standards of performance. For designated facilities where the EPA's presumptive standards include associated monitoring, reporting, and/or recordkeeping requirements, the EPA has determined that such requirements are necessary to ensure compliance. Thus, for those designated facilities, the EPA is proposing to require that the standards of performance established by States maintain the same monitoring, reporting, and recordkeeping requirements, or equivalent requirements. For example, the EG's presumptive standards for fugitives monitoring at well sites includes requirements for owners and operators to maintain records and submit reports that demonstrate compliance with the monitoring and repair provisions. As such, the EPA is proposing that the portion of the State plan which

[339] 40 CFR 60.24a(d) additionally required state plans to include increments of progress for any compliance schedule that extended more than 24 months after the state plan submittal date. While the substantive requirement for increments of progress was not challenged and remains effective, the timing aspect of this provision was vacated by the D.C. Circuit. *Am. Lung Assoc.,* 985 F.3d at 991. The EPA intends to address the timing aspect of this provision in the near future.

establishes standards of performance for that designated facility also includes requirements for owners and operators to maintain records and submit reports that demonstrate compliance with the monitoring and repair provisions. Where a State plan adopts standards of performance that differ from the presumptive standards, the plan may accordingly include different monitoring, reporting, and recordkeeping requirements than those in the presumptive standards, but such requirements must be appropriate for the implementation and enforcement of the standards. For components of a State plan that differ from any presumptively approvable aspects of the final EG, the EPA will review the approvability of such components through notice and comment rulemaking.

Emissions Inventories. The implementing regulations at 40 CFR 60.25a contain generally applicable requirements for emission inventories, source surveillance, and reports. State plans must include provisions to meet these requirements as well. Section 60.25a further specifies that such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable standards of performance. Typically, the EPA would expect that State plans would present this information on a source-specific or unit-specific level. However, the EPA recognizes that due to the very large number of existing oil and natural gas sources,[340] and the frequent change of configuration and/or ownership, that it may not be practical to require States to compile this information in the same way that is typically expected for other industries under other EG. Therefore, the EPA is soliciting comment on whether to supersede the requirements of 40 CFR 60.25a(a) for purposes of this EG. The EPA may supersede any requirement in its implementing regulations for CAA section 111(d) if done so explicitly in the EG. See 40 CFR 60.20a(a)(1). Specially, for the reasons explained previously, the EPA believes that in this context it could be difficult for the State plans to include ''an inventory of all designated facilities, including emission data for the designated pollutants and information related to emissions as specified in appendix D to this part'' as required by the first sentence in 40 CFR 60.25a(a). The EPA understands that States may not have such an inventory of all designated facilities already available and that creating such an inventory could be resource intensive. Likewise, the EPA understands that States may not have site-specific emissions data for each designated facility, and that creating such an inventory could also be very resource intensive. The EPA does not believe that such detailed information is necessary for States to develop standards of performance, and that standards of performance could be developed with a different type of emissions inventory data. Therefore, in order to avoid the potential burden that could be imposed by applying 40 CFR 60.25a(a) as written to this EG, the EPA is soliciting comment on whether the Agency should supersede the requirements of 40 CFR 60.25a(a) for purposes of this EG, and replace that requirement with a different emissions inventory requirement that seeks to represent the same general type of information but allows States to utilize existing inventories and emissions data. An example of an inventory that could be leveraged, and on which the EPA specifically solicits comment, is the GHGRP. The EPA envisions a superseding requirement that would not impose such a resource intensive burden on States by allowing use of an inventory of GHG emissions data and operational data for designated facilities during the most recent calendar year for which data is available at the time of State plan development and/or submission. The emissions inventory data submitted for this purpose could be derived from the GHGRP, and/or other available existing inventory information available to the State. The EPA recognizes that in this situation the facility definitions used for purposes of compiling the emissions inventory data might not be fully aligned with the designated facilities in the EG, and that it is possible that there could be designated facilities under this EG that are not required to report under the emissions inventory program being relied upon. Further, the EPA recognizes that the GHGRP may include a reporting threshold and/or utilize emission factors in a different manner than the EG. The EPA solicits comment on whether it is appropriate to utilize or supersede 40 CFR 60.25a(a) for purposes of this EG. Specifically, the EPA solicits comment on the practicality of States compiling an inventory for all designated facilities and on what reasonable alternatives may be more practical.

Meaningful Engagement. The fundamental purpose of CAA section 111 is to reduce emissions from certain stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare. Therefore, a key consideration in the State's development of a State plan pursuant to an EG promulgated under CAA section 111(d) is the potential impact of the proposed plan requirements on public health and welfare. A robust and meaningful public participation process during State plan development is critical to ensuring that these impacts are fully considered. The EPA is proposing and soliciting comment on requiring States to perform outreach and meaningful engagement with overburdened and underserved communities during the development process of their State plan pursuant EG OOOOc.

States often rely primarily on public hearings as the foundation of their public engagement in their State plan development process because a public hearing is explicitly required pursuant to the applicable regulations. The existing provisions in subpart Ba (40 CFR 60.23a(c)–(f)) detail the public participation requirements associated with the development of a CAA section 111(d) State plan. Per these implementing regulations, States must provide certain notice of and conduct one or more public hearings on their State plan before such plan is adopted and submitted to the EPA for review and action. However, robust and meaningful public involvement in the development of a State plan should go beyond the minimum requirement to hold a public hearing. Meaningful engagement should include ensuring that States share information with and solicit input from stakeholders at critical junctures during plan development, which helps ensure that a plan is adequately addressing the potential impacts to public health and welfare that are the core concern of CAA section 111.

This early engagement is especially important for those stakeholders and communities directly impacted by the GHG emissions from designated facilities within the Crude Oil and Natural Gas source category being addressed in a State plan developed pursuant the EG OOOOc. As reflected in section VI and VII of the preamble, engagement with stakeholders and in particular adjacent communities was key during the development of the proposed NSPS and EG and will be key in the development of corresponding State plans that achieve the intended emission reductions and provide benefits to these communities. In

[340] In the U.S. the EPA has identified over 15,000 oil and gas owners and operators, around 1 million producing onshore oil and gas wells, about 5,000 gathering and boosting facilities, over 650 natural gas processing facilities, and about 1,400 transmission compression facilities.

recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways to protect them from adverse public health and environmental effects of air pollution emitted from sources within the Oil and Natural Gas Industry that are addressed in this proposed rulemaking. For these reasons, the EPA is proposing to include an additional requirement associated with the adoption and submittal of State plans pursuant to EG OOOOc (in addition to the current requirements of Subpart Ba) by requiring States to meaningfully engage with members of the public, including overburdened and underserved communities, during the plan development process and prior to adoption and submission of the plan to the EPA.

The EPA's authority for proposing to include an additional requirement for meaningful engagement is provided by the authority of both CAA sections 111(d) and 301(a)(1). Under CAA section 111(d), one of the EPA's obligations is to promulgate a process ''similar'' to that of CAA section 110 under which States submit plans that implement emission reductions consistent with the BSER. CAA section 110(a)(1) requires States to adopt and submit State implementation plans (SIPs) after ''reasonable notice and public hearings.'' The Act does not define what constitutes ''reasonable notice'' under CAA section 110, and therefore the EPA may reasonably interpret this requirement in promulgating a process under which States submit section 111(d) plans. The EPA proposes to give the ''reasonable notice'' requirement additional and separate meaning from the ''public hearing'' requirement. Therefore, in addition to the generally applicable public participation requirements in 40 CFR 60.23a(c)–(f) (which presently only require public notification of a public hearing), the EPA proposes to promulgate these additional meaningful engagement requirements within the EG OOOOc to ensure that the public has reasonable notice of relevant information and the opportunity to participate in the State plan development throughout the process. Given the public health and welfare objectives of CAA section 111(d) in regulating specific existing sources, the EPA believes it is reasonable to require meaningful engagement as part of the public participation process in order to further these objectives. Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations ''as are necessary to carry out [its] functions under [the CAA].'' The proposed meaningful engagement requirements would effectuate the EPA's function under CAA section 111(d) in prescribing a process under which States submit plans to implement the statutory directives of this section.

The proposed meaningful engagement requirements for State plan development would ensure that the process is inclusive, effective, and accessible to all. For this reason, the process must not be disproportionate or favor certain stakeholders. During the development of the State plan pursuant to EG OOOOc, the EPA expects States to identify any underserved or overburdened communities potentially impacted by the State plan. If any communities are identified, States should engage with these communities and develop public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to meaningful participation and ensure meaningful community representation in the process, recognizing diverse constituencies within any particular community. Community participation should occur as early as possible if it is to be meaningful. Meaningful engagement includes targeted outreach to underserved and overburdened communities, sharing information, and soliciting input on State plan development and on any accompanying assessments. The EPA uses the term ''underserved'' to mean populations sharing a particular characteristic, as well as geographic communities, that have been systemically denied a full opportunity to participate in aspects of economic, social, and civic life, and the term ''overburdened'' in referring to minority, low-income, Tribal, and indigenous populations or communities in the U.S. that potentially experience disproportionate environmental harms and risks as a result of greater vulnerability to environmental hazards . This increased vulnerability may be attributable to an accumulation of both negative and lack of positive environmental, health, economic, or social conditions within these populations or communities. This engagement will help ensure that State plans achieve meaningful emission reductions, that overburdened communities partake in the benefits and gains of the State plan, and that these communities are protected from being adversely impacted by the State plan. The EPA recognizes that emissions from designated sources could cross State borders, and therefore may affect underserved and overburdened communities in neighboring States. The EPA is soliciting comment on how meaningful engagement should apply to communities outside of the State that is developing a State plan, for example if a State should coordinate with the neighboring State for outreach or directly contact the affected community.

In sections VI and VII of this preamble the EPA addresses environmental justice considerations, implications, and stakeholder outreach the agency is taking to help ensure vulnerable communities are not disproportionately impacted by this rule. The considerations, analyses, and outreach presented in these preamble sections could help States in designing, planning, and developing their own outreach and engagement plans associated with the development and implementation of their State plans to reduce emissions of GHGs from designated facilities within the Crude Oil and Natural Gas source category.

To ensure that robust and meaningful public engagement process occurs as the States develop their CAA 111(d) plans, the EPA is also proposing to include a requirement within EG OOOOc for States to demonstrate in their plan submittal how they provided meaningful and timely engagement with all pertinent stakeholders, including, as necessary, industries and small businesses, as well as low-income communities, communities of color, and indigenous populations living near the designated facilities and who may be otherwise potentially affected by the State's plan. The State would be required to describe, in their plan submittal, the engagement they had with their stakeholders, including their overburdened and underserved communities. Additionally, the EPA would evaluate the States' demonstrations regarding meaningful public engagement as part of its completeness evaluation of a State plan submittal. If a State plan submission does not meet the required elements for public participation, including requirements for meaningful engagement, this may be ground for the EPA to find the submission incomplete or to disapprove the plan.

The EPA further notes that the implementing regulations allow a State to request the approval of different State procedures for public participation pursuant 40 CFR 60.23a(h). The EPA proposes to require that such alternate State procedures do not supersede the meaningful engagement requirements being proposed within EG OOOOc, so that a State would still be required to comply with the meaningful

participation requirements even if they apply for a different procedure than the other public notice and hearing requirements under 40 CFR 60.23a. As provided in 40 CFR 60.23a(h), the EPA is proposing that States may also apply for, and the EPA may approve, alternate meaningful engagement procedures if, in the judgement of the Administrator, the procedures, although different from the requirements of within EG OOOOc, in fact provide for adequate notice to and meaningful participation of the public.

D. Components of State Plan Submission

Under CAA section 111(d)(2), the EPA has an obligation to determine whether each State plan is ''satisfactory.'' Therefore, in addition to identifying the components that the EG must include, the EPA's implementing regulations for CAA section 111(d) identify additional components that a State plan must include. Many of these requirements are found in 40 CFR 60.23a, 60.24a, 60.25a, and 60.26a. These provisions include requirements for components such as the following: Procedures a State must go through for adopting a plan before submitting it to the EPA; the stringency of standards of performance and compliance timelines; emission inventories, reporting, and recordkeeping; and, the legal authority a State must show in adopting a plan. These requirements are also generally contained in a list of required State plan elements, referred to as the State plan completeness criteria, found at 40 CFR 60.27a(g)(2)–(3). If the EPA determines that a submitted plan does not meet these criteria then the State is treated as not submitting a plan and the EPA has a duty to promulgate a Federal plan for that State. See CAA section 111(d)(2)(A) and 40 CFR 60.27a(g)(1). If the EPA determines a plan submission is complete, such determination does not reflect a judgment on the eventual approvability of the submitted portions of the plan, which instead must be made through notice-and-comment rulemaking. The completeness criteria do not apply to States without any designated facilities because these States are directed to submit to the Administrator a letter of negative declaration certifying that there are no designated facilities, as defined by the EPA's emissions guidelines, located within the State. See 40 CFR 60.23a(b). No plan is required for States that do not have any designated facilities. Designated facilities located in States that mistakenly submit a letter of negative declaration would be subject to a Federal plan until a State plan regulating those facilities becomes approved by the EPA.

The EPA established nine administrative and six technical criteria for complete State plans under CAA section 111(d). See 40 CFR 60.27a(g)(2)–(3). If a State plan does not include even one of these criteria, then the State plan may be deemed incomplete by the EPA. States that are familiar with the SIP submittal process under CAA section 110 will be familiar with the completeness criteria found in 40 CFR part 51, appendix V. While the completeness criteria for State plan submittals found at 40 CFR 60.27a(g)(2)–(3) is somewhat similar to the SIP submittal criteria in appendix V, it is not exactly the same. As such, even States that are familiar with the SIP submittal process under CAA section 110 are strongly encouraged to review the completeness criteria in 40 CFR 60.27a(g)(2)–(3) as well as the other State plan requirements found in 40 CFR 60.23a, 60.24a, 60.25a, and 60.26a early in their planning process.

In short, the administrative completeness criteria require that the State's plan include a formal submittal letter and a copy of the actual State regulations themselves, as well as evidence that the State has legal authority to adopt and implement the plan, actually adopted the plan, followed State procedural laws when adopting the plan, gave public notice of the changes to State law, held public hearing(s) if applicable, and responded to State-level comments. For a detailed description regarding the public hearing requirement, see 40 CFR 60.23a. For a detailed description of what the State plan must include in terms of evidence that the State has legal authority to adopt and implement the plan, see 40 CFR 60.26a. States are strongly encouraged to review the State plan requirements included in 40 CFR 60.23a and 60.26a in conjunction with the administrative completeness criteria in 40 CFR 60.27a.

The technical criteria require that the State's plan identify the designated facilities, the standards of performance, the geographic scope of the plan, monitoring, recordkeeping and reporting requirements (both for facilities to ensure compliance and for the State to ensure performance of the plan as a whole), and compliance schedules. The technical criteria further require that the State demonstrate that the plan is projected to achieve emission performance under the EG and that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable. As previously described, it may not be feasible to quantify certain non-numerical standards of performance. The EPA is proposing to require States demonstrate that each standard of performance is quantifiable, as feasible. For a detailed description of the State plan requirements regarding standards of performance, see section XIV.C and 40 CFR 60.24a.

In addition to these technical criteria, 40 CFR 60.25a(a) requires that State plans include certain emissions data for the designated facilities. As explained previously, the EPA is soliciting comment on superseding that requirement for this EG. Further, § 60.25a provides a detailed description of what the State plan is required to include in terms of certain compliance monitoring and reporting. States are strongly encouraged to review the State plan requirements included in 40 CFR 60.24a and 60.25a in conjunction with the technical completeness criteria in 40 CFR 60.27a.

E. Timing of State Plan Submissions and Compliance Times

The EPA acknowledges that the D.C. Circuit has vacated certain timing provisions within 40 CFR part 60, subpart Ba. *Am. Lung Assoc.* v. *EPA,* 985 F.3d at 991 (DC Cir. 2021). These provisions include timing requirements for when State plans are due upon publication of a final EG, for EPA's action on a State plan submission, and for EPA's promulgation of a Federal plan. The Agency plans to undertake rulemaking to address the provisions vacated under the court's decision in the near future. At this time, the EPA is soliciting comment on any facts and circumstances that are unique to the oil and natural gas industry that the EPA should consider when proposing a timeline for plan submission applicable to a final EG for this source category. We recognize that the public needs to have an opportunity to review and comment on the new timelines that will address these regulatory gaps, including in particular the timeline for State plan submission, and the Agency is committed to publishing this proposed timeline for comment when available.

In accordance with 40 CFR 60.22a(b)(5), the EPA's EG is to provide information for the development of State plans that includes, among other things, ''the time within which compliance with standards of performance can be achieved.'' The EPA is proposing those compliance times for comment. See 40 CFR 60.25a(c). Each State plan must include compliance schedules that, subject to certain exception, require compliance as expeditiously as practicable but no later

than the compliance times included in the relevant EG. *Id.* at 60.24a(a) and (c). States are free to include compliance times in their plans that are earlier than those included in the final EG. *Id.* at 40 CFR 60.24a(f)(2). If a State chooses to include a compliance schedule in their plan that extends for a certain period beyond the date required for submittal of the plan, then ''the plan must include legally enforceable increments of progress to achieve compliance for each designated facility.'' [341] *Id.* at 40 CFR 60.24a(d). To the extent a State accounts for remaining useful life and other factors in applying a less stringent standard of performance (than required by the EPA in the final EG), the State must also include a compliance deadline that it can demonstrate appropriately correlates with that standard.

The EPA is proposing to require that State plans impose a compliance timeline on designated facilities to require final compliance with the standards of performance as expeditiously as practicable, but no later than two years following the State plan submittal deadline. As explained above, the EPA anticipates proposing a State plan submission deadline in a separate document. The EPA believes that two years is an appropriate amount of time for designated facilities to ensure compliance based on the EPA's general understanding of the industry and the proposed presumptive standards. However, the EPA recognizes that there are many existing sources in the oil and natural gas industry that would be subject to a State plan if the presumptive standards are finalized in a similar manner as proposed in this document, and that there may be a wide range of configurations that may be present at any given facility. Further, the EPA recognizes that it may be appropriate to require different compliance times for different designated facilities. For example, it may be appropriate to require one compliance schedule for reciprocating compressors and a different compliance schedule for storage vessels. There may not be a one-size-fits-all approach to compliance times that is appropriate for all designated facilities.

Accordingly, the EPA is soliciting comment on whether a two-year compliance schedule is appropriate for all designated facilities, or whether the EG should require a shorter or longer compliance schedule. The EPA is further soliciting comment on whether it would be appropriate to establish different compliance schedules for different designated facilities, and if so, what are the appropriate timelines for each designated facility. The EPA is soliciting comment on this matter to collect information that might inform different compliance timeline(s) that Agency may propose for comment in the future via a supplemental proposal.

F. EPA Action on State Plans and Promulgation of Federal Plans

While CAA section 111(d)(1) authorizes States to develop State plans that establish standards of performance and provides States with certain discretion in determining the appropriate standards, CAA section 111(d)(2) provides the EPA a specific oversight role with respect to such State plans. This latter provision authorizes the EPA to prescribe a Federal plan for a State ''in cases where the State fails to submit a satisfactory plan.'' The States must therefore submit their plans to the EPA, and the EPA must evaluate each State plan to determine whether each plan is ''satisfactory.'' The EPA's implementing regulations for CAA section 111(d) accordingly provide procedural requirements for the EPA to make such a determination. See 40 CFR 60.27a.

Upon receipt of a State plan, the EPA is first required to determine whether the State plan submittal is complete in accordance with the completeness criteria explained above. See 40 CFR 60.27a(g)(1). The EPA would then have a set period of time to act on any State plan that is deemed complete.[342] If the EPA determines that the State plan submission is incomplete, then the State will be treated as not having made the submission, and the EPA would be required to promulgate a Federal plan for the designated facilities in that State. Likewise, if a State does not make any submission then the EPA is required to promulgate a Federal plan. If the EPA does not make an affirmative determination regarding completeness of the State plan submission within a certain amount of time from receiving the State plan, then the submission is deemed complete by operation of law. *Id.*

If a State has submitted a complete plan, then the EPA is required to evaluate that plan submission for approvability in accordance with the CAA, EPA's implementing regulations, and the applicable EG. The EPA may approve or disapprove the State plan submission in whole or in part. See 40 CFR 60.27a(b). If the EPA approves the State plan submission, then that State plan becomes Federally enforceable. If the EPA disapproves the required State plan submission, in whole or in part, then the EPA is required to promulgate a Federal plan for the designated facilities in that State via a notice-and-comment rulemaking, and with an opportunity for public hearing. See 40 CFR 60.27a(c) and (f). In either scenario that would give rise to the EPA's duty to promulgate a Federal plan (a finding that a State did not submit a complete plan or a disapproval of a State plan), the EPA would not be required to promulgate the Federal plan if the State corrects the deficiency giving rise to the EPA's duty and the EPA approves the State's plan before promulgating the Federal plan. Requirements regarding the content of a Federal plan are included in 40 CFR 60.27a(e).

G. Tribes and the Planning Process Under CAA Section 111(d)

Under the Tribal Authority Rule (TAR) adopted by the EPA, Tribes may seek authority to implement a plan under CAA section 111(d) in a manner similar to a State. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a State for purposes of developing a Tribal Implementation Plan (TIP) implementing the EG. If a Tribe obtains approval and submits a TIP, the EPA will generally use similar criteria and follow similar procedures as those described above for State plans when evaluating the TIP submission, and will approve the TIP if appropriate. The EPA is committed to working with eligible Tribes to help them seek authorization and develop plans if they choose. Tribes that choose to develop plans will generally have the same flexibilities available to States in this process. If a Tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for areas of Indian country where designated facilities are located. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves an applicable TIP applicable to those facilities.

[341] As previously noted, the timing aspect of this provision was vacated by the D.C. Circuit. *Am. Lung Assoc.* v. *EPA,* 985 F.3d 914 at 991. The EPA intends to address the timing aspect of this provision in the near future.

[342] As explained above, the D.C. Circuit vacated the timing provisions regarding EPA's action on a state plan submission, and EPA's promulgation of a Federal plan. *Am. Lung Assoc.* v. *EPA,* 985 F.3d at 991. The Agency plans to undertake rulemaking to address the provisions vacated under the court's decision in the near future.

XV. Prevention of Significant Deterioration and Title V Permitting

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 PSD preconstruction permit program and the CAA title V operating permit program. The EPA is proposing to include provisions in the regulations that explicitly address some of these potential implications, consistent with our experience in prior rules regulating GHGs. The EPA included and explained the basis for similar provisions when promulgating 2016 NSPS OOOOa, as well as the 2015 subpart TTTT NSPS for electric utility generating units. See 81 FR 35823, 35871 (June 3, 2016); 80 FR 64509, 64628 (October 23, 2015). The discussion in these prior rule preambles equally applies to the oil and gas sources subject to NSPS OOOOb and EG OOOOc.

In summary, in light of the U.S. Supreme Court's decision in *Utility Air Regulatory Group* v. *Environmental Protection Agency,* 573 U.S. 302 (2014) (*UARG*), the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source (or modification thereof) for the purpose of PSD applicability. Certain portions of the EPA's PSD regulations (specifically, the definition of ''subject to regulation'') effectively ensure that most sources will not trigger PSD solely by virtue of their GHG emissions. *E.g.,* 40 CFR 51.166(b)(48)(iv), 52.21(b)(49)(iv).[343] However, the EPA's PSD regulations (specifically, the definition of ''regulated NSR pollutant'') provide additional bases for PSD applicability for pollutants that are regulated under CAA section 111. To address this latter component of PSD applicability, the EPA is proposing to add provisions within the subpart OOOOb NSPS and subpart OOOOc EG to help clarify that the promulgation of GHG standards under section 111 will not result in additional sources becoming subject to PSD based solely on GHG emissions, which would be contrary to the holding in *UARG.* These provisions will be similar to those in the 2016 NSPS OOOOa and other section 111 rules that regulate GHGs. *See, e.g.,* 40 CFR 60.5360a(b)(1)–(2), 60.5515(b)(1)–(2).

The EPA understands there are also concerns that if methane were to be subject to regulation as a separate air pollutant from GHGs, sources that emit methane above the PSD thresholds or modifications that increase methane emissions could be subject to the PSD program. To address this concern and for purposes of clarity, the EPA is proposing to adopt regulatory text within subpart OOOOb NSPS and subpart OOOOc EG to clarify that the air pollutant that is subject to regulation is GHGs, even though the standard is expressed in the form of a limitation on emission of methane. This language will be substantially similar to language found in, for example, the 2016 NSPS OOOOa and other rules. See, *e.g.,* 40 CFR 60.5360a(a), 60.5515(a).

For sources that are subject to the PSD program based on non-GHG emissions, the CAA continues to require that PSD permits satisfy the best available control technology (BACT) requirement for GHGs. Based on the language in the PSD regulations, the EPA and States may continue to limit the application of BACT to GHG emissions in those circumstances where a new source emits GHGs in the amount of at least 75,000 tpy on a CO_2 Eq. basis or an existing major source increases emissions of GHGs by more than 75,000 tpy on a CO_2 Eq. basis. See 40 CFR 51.166(b)(48)(iv), 52.21(b)(49)(iv). The proposed revisions to the regulatory text within subparts OOOOb NSPS and OOOOc EG will ensure that this BACT applicability level remains operable to sources of GHGs regulated under CAA section 111, as have similar revisions in prior rules. See, *e.g.,* 40 CFR 60.5360a(b)(1)–(2), 60.5515(b)(1)–(2). This proposed rule will not require any additional revisions to SIPs.

Regarding title V, the *UARG* decision similarly held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source for the purpose of title V applicability. Promulgation of CAA section 111 requirements for GHGs will not result in the EPA imposing a requirement that stationary sources obtain a title V permit solely because such sources emit or have the potential to emit GHGs above the applicable major source thresholds.[344]

To be clear, however, unless exempted by the Administrator through regulation under CAA section 502(a), any source, including a ''non-major source,'' subject to a standard or regulation under section 111 is required to apply for, and operate pursuant to, a title V permit that ensures compliance with all applicable CAA requirements for the source, including any GHG-related applicable requirements. This aspect of the title V program is not affected by *UARG.*[345] The EPA proposes to include an exemption from the obligation to obtain a title V permit for sources subject to NSPS OOOOb and EG OOOOc, unless such sources would otherwise be required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a), as the EPA did in NSPS OOOO and OOOOa.[346] See 40 CFR 60.5370, 60.5370a. However, sources that are subject to the CAA section 111 standards promulgated in this rule and that are otherwise required to obtain a title V permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) will be required to apply for, and operate pursuant to, a title V permit that ensures compliance with all applicable CAA requirements, including any GHG-related applicable requirements.

XVI. Impacts of This Proposed Rule

A. What are the air impacts?

The EPA projected that, from 2023 to 2035, relative to the baseline, the proposed NSPS OOOOb and EG OOOOc will reduce about 41 million short tons of methane emissions reductions (920 million tons CO_2 Eq.), 12 million short tons of VOC emissions reductions, and 480 thousand short tons of HAP emission reductions from facilities that are potentially affected by this proposal. The EPA projected regulatory impacts beginning in 2023 as that year represents the first full year of implementation of the proposed NSPS OOOOb. The EPA assumes that emissions impacts of the proposed EG OOOOc will begin in 2026. The EPA projected impacts through 2035 to illustrate the accumulating effects of this rule over a longer period. The EPA

[343] In 2016, the EPA proposed additional revisions to the PSD and title V regulations that would address these and other concerns. 81 FR 58110 (October 3, 2016).

[344] Additional regulatory text, based on that in prior rules, will further ensure that title V regulations are not applied to GHGs solely because they are regulated under CAA section 111. See, *e.g.,* 40 CFR 60.5360a(b)(3)–(4), 60.5515(b)(3)–(4). The EPA understands that concerns regarding the regulation of methane as a separate air pollutant (described with respect to PSD) also apply to title V. The EPA's proposed regulatory text—clarifying that the pollutant subject to regulation is GHGs—will similarly address these concerns with respect to title V. See, *e.g.,* 40 CFR 60.5360a(a), 60.5515(a).

[345] See Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, Office of Enforcement and Compliance Assurance, to Regional Administrators, Regions 1–10, *Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014) at 5.

[346] The EPA provided the rationale for exempting this source category from the title V permitting requirements during the rulemaking for the 2012 NSPS OOOO. See 76 FR 52737, 52751 (August 23, 2011). That rationale continues to apply to this source category.

did not estimate impacts after 2035 for reasons including limited information, as explained in the RIA.

B. What are the energy impacts?

The energy impacts described in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section in XVI.D. There will likely be minimal change in emissions control energy requirements resulting from this rule. Additionally, this proposed action continues to encourage the use of emission controls that recover hydrocarbon products that can be used on-site as fuel or reprocessed within the production process for sale.

C. What are the compliance costs?

The PV of the regulatory compliance cost associated with the proposed NSPS OOOOb and EG OOOOc over the 2023 to 2035 period was estimated to be $13 billion (in 2019 dollars) using a 3-percent discount rate and $10 billion using a 7-percent discount rate. The EAV of these cost reductions is estimated to be $1.2 billion per year using a 3-percent discount rate and $1.2 billion per year using a 7-percent discount rate.

These estimates do not, however, include the producer revenues associated with the projected increase in the recovery of saleable natural gas. Estimates of the value of the recovered product have been included in previous regulatory analyses as offsetting compliance costs. Using the 2021 Annual Energy Outlook (AEO) projection of natural gas prices to estimate the value of the change in the recovered gas at the wellhead projected to result from the proposed action, the EPA estimated a PV of regulatory compliance costs of the proposed rule over the 2023 to 2035 period of $7.2 billion using a 3-percent discount rate and $6.3 billion using a 7-percent discount rate. The corresponding estimates of the EAV of compliance costs after accounting for the recovery of saleable natural gas were $680 million per year using a 3-percent discount rate and $760 million using a 7-percent discount rate.

D. What are the economic and employment impacts?

The EPA conducted an economic impact and distributional analysis for this proposal, as detailed in section 4 of the RIA for this proposal. To provide a partial measure of the economic consequences of the proposed NSPS OOOOb and EG OOOOc, the EPA developed a pair of single-market, static partial-equilibrium analyses of national crude oil and natural gas markets. We implemented the pair of single-market analyses instead of a coupled market or general equilibrium approach to provide broad insights into potential national-level market impacts while providing maximum analytical transparency. We estimated the price and quantity impacts of the proposed NSPS OOOOb and EG OOOOc on crude oil and natural gas markets for a subset of years within the time horizon analyzed in the RIA. The models are parameterized using production and price data from the U.S. Energy Information Administration and supply and demand elasticity estimates from the economics literature.

The RIA projects that regulatory costs are at their highest in 2026, the first year the requirements of both the proposed NSPS OOOOb and EG OOOOc are assumed to be in effect and will represent the year with the largest market impacts based upon the partial equilibrium modeling. We estimated that the proposed rule could result in a maximum decrease in annual natural gas production of about 249 million Mcf in 2026 (or about 0.8 percent of natural gas production) with a maximum price increase of $0.05 per Mcf (or about 1.8 percent). We estimated the maximum annual reduction in crude oil production would be about 12.2 million barrels (or about 0.3 percent of crude oil production) with a maximum price increase of about $0.06 per barrel (or less than 0.1 percent).

Before 2026, the modeled market impacts are much smaller than the 2026 impacts as only the incremental requirements under the proposed NSPS OOOOb are assumed to be in effect. As regulatory costs are projected to decline after 2026, the modelled market impacts for years after 2026 are smaller than the peaks estimated for 2026. Please see section 4.1 of the RIA for more detail on the formulation and implementation of the model as well as a discussion of several important caveats and limitations associated with the approach.

As discussed in the RIA for this proposal, employment impacts of environmental regulations are generally composed of a mix of potential declines and gains in different areas of the economy over time. Regulatory employment impacts can vary across occupations, regions, and industries; by labor and product demand and supply elasticities; and in response to other labor market conditions. Isolating such impacts is a challenge, as they are difficult to disentangle from employment impacts caused by a wide variety of ongoing, concurrent economic changes.

The oil and natural gas industry directly employs approximately 140,000 people in oil and natural gas extraction, a figure which varies with market prices and technological change, and employs a large number of workers in related sectors that provide materials and services.[347] As indicated above, the proposed NSPS OOOOb and EG OOOOc are projected to cause small changes in oil and natural gas production and prices. As a result, demand for labor employed in oil and natural gas-related activities and associated industries might experience adjustments as there may be increases in compliance-related labor requirements as well as changes in employment due to quantity effects in directly regulated sectors and sectors that consume oil and natural gas products.

E. What are the benefits of the proposed standards?

To satisfy the requirement of E.O. 12866 and to inform the public, the EPA estimated the climate and health benefits due to the emissions reductions projected under the proposed NSPS OOOOb and EG OOOOc. The EPA expects climate and health benefits due to the emissions reductions projected under the proposed NSPS OOOOb and EG OOOOc. The EPA estimated the global social benefits of CH_4 emission reductions expected from this proposed rule using the SC–CH_4 estimates presented in the ''Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990 (IWG 2021)'' published in February 2021 by the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG). The SC–CH_4 is the monetary value of the net harm to society associated with a marginal increase in emissions in a given year, or the benefit of avoiding that increase. In principle, SC–CH_4 includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–CH_4 therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost

[347] Employment figure drawn from the Bureau of Labor Statistics Current Employment Statistics for NAICS code 211.

analyses of policies that affect CH_4 emissions.

The interim SC–GHG estimates were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. As a member of the IWG involved in the development of the February 2021 Technical Support Document (TSD): Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), the EPA agrees that the interim SC–GHG estimates represent the most appropriate estimate of the SC–GHG until revised estimates have been developed reflecting the latest, peer-reviewed science.

The EPA estimated the PV of the climate benefits over the 2023 to 2035 period to be $55 billion at a 3-percent discount rate. The EAV of these benefits is estimated to be $5.2 billion per year at a 3-percent discount rate. These values represent only a partial accounting of climate impacts from methane emissions and do not account for health effects of ozone exposure from the increase in methane emissions.

Under the proposed NSPS OOOOb and EG OOOOc, the EPA expects that VOC emission reductions will improve air quality and are likely to improve health and welfare associated with exposure to ozone, $PM_{2.5}$, and HAP. Calculating ozone impacts from VOC emissions changes requires information about the spatial patterns in those emissions changes. In addition, the ozone health effects from the proposed rule will depend on the relative proximity of expected VOC and ozone changes to population. In this analysis, we have not characterized VOC emissions changes at a finer spatial resolution than the national total. In light of these uncertainties, we present an illustrative screening analysis in Appendix B of the RIA based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017 and do not include the results of this analysis in the estimate of benefits and net benefits projected from this proposal.

XVII. Statutory and Executive Order Reviews

Additional information about these statutes and EOs can be found at *https://www.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 proposed action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, ''Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review'', is available in the docket and describes in detail the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates.

B. Paperwork Reduction Act (PRA)

The information collection activities in the proposed amendments for 40 CFR part 60, subparts OOOO and OOOOa, have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The information collection activities in the proposed rules for 40 CFR part 60, subparts OOOOb and OOOOc, will be submitted for approval to OMB under the PRA as part of a supplemental proposed rule.[348] The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2523.04. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The final rule for this action will include updates to the CFR to reflect the disapproval of the 2020 Policy Rule that was effectuated by the joint resolution enacted pursuant to the CRA on June 30, 2021. The EPA is not soliciting comment on these updates. In addition, this rule proposes amendments to the 2016 NSPS OOOOa to address (1) certain resulting inconsistencies between the VOC and methane standards resulting from the CRA, and (2) rescind certain determinations made in the 2020 Technical Rule, with respect to fugitive emissions monitoring at low production well sites and gathering and boosting stations as they were not supported by the record for that rule, or by our subsequent information and analysis. The EPA is also proposing further amendments to its 2016 NSPS OOOOa to address technical and implementation issues.

This ICR reflects the EPA's proposed amendments to the 2016 NSPS OOOOa. The information collected will be used by the EPA and delegated State and local agencies to determine the compliance status of affected facilities subject to the rule.

The respondents are owners or operators of onshore oil and natural gas affected facilities (40 CFR 60.5365a). For the purposes of this ICR, it is assumed that oil and natural gas affected facilities located in the U.S. are owned and operated by the oil and natural gas industry, and that none of the affected facilities in the U.S. are owned or operated by State, local, Tribal or the Federal government. All affected facilities are assumed to be privately owned for-profit businesses.

The EPA estimates an average of 3,268 respondents will be affected by NSPS OOOOa over the three-year period (2021–2023). The average annual burden for the recordkeeping and reporting requirements for these owners and operators is 283,030 person-hours, with an average annual cost of $93,779,839 over the three-year period (2021–2023).

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

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 3,268.

Frequency of response: Varies depending on affected facility.[349]

Total estimated burden: 283,030 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $93,779,839 (2019$), which includes no capital or O&M costs.

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

[348] While not quantified in this proposal, the EPA anticipates the estimated ICR burden of proposed NSPS OOOOb and EG OOOOc to be at least as burdensome as NSPS OOOOa. The EPA anticipates some sources may have similar ICR burden to NSPS OOOOa. Examples of these include fugitive emissions from compressor stations, pneumatic controllers at gas processing, centrifugal compressors, pneumatic pumps, well completions, and sweetening units. The EPA anticipates other sources could have dissimilar burden to NSPS OOOOa because the standards are different or are brand new to this proposal. Examples of these include fugitive emissions from well sites, storage vessels, pneumatic controllers, reciprocating compressors, liquids unloading, and equipment leaks at gas plants.

[349] The specific frequency for each information collection activity within this request is shown in Tables 1a through 1d of the Supporting Statement in the public docket.

provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than December 15, 2021. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry whose parent company has revenues or numbers of employees below the SBA Size Standards for the relevant NAICS code; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review in the docket and is summarized here.

The IRFA describes the reason why the proposed rule is being considered and describes the objectives and legal basis of the proposed rule, as well as discusses related rules affecting the oil and natural gas sector. The IRFA describes the EPA's examination of small entity effects prior to proposing a regulatory option and provides information about steps taken to minimize significant impacts on small entities while achieving the objectives of the rule.

The EPA also summarized the potential regulatory cost impacts of the proposed rule and alternatives in Section 2 of the RIA. The analysis in the IRFA drew upon some of the same analyses and assumptions as the analyses presented in the RIA. The IRFA analysis is presented in its entirely in Section 4.3 of the RIA.

We estimated cost-to-sales ratios (CSR) for each small entity to summarize the impacts of the proposed rule on small entities. In the processing segment, we find that average compliance costs are expected to be negative, and no entity has a cost-to-sales ratio greater than either 1 percent or 3 percent. In the production segment, when expected revenues from natural gas product recovery are included, 101 small entities (7.2 percent) have cost-to-sales ratios greater than 1 percent, but none have cost-to-sales ratios greater than 3 percent. When expected revenues from natural gas product recovery are excluded, the number of small entities with cost-to-sales ratios greater than 1 percent increases to 331 (23 percent); about half of those small entities (11 percent) also have cost-to-sales ratios greater than 3 percent.

The analysis above is subject to a number of caveats and limitations. These are discussed in detail in the IRFA, as well as in Section 4.3 of the RIA. As required by section 609(b) of the RFA, the EPA also convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. The SBAR Panel evaluated the assembled materials and small-entity comments on issues related to elements of an IRFA. A copy of the full SBAR Panel Report is available in the rulemaking docket.

D. Unfunded Mandates Reform Act (UMRA)

The proposed NSPS and EG do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and do not significantly or uniquely affect small governments. The proposed NSPS does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate or the private sector in any one year. For projected cost estimates, see ''Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review'', which is available in the docket. The EG is proposed under CAA section 111(d) and does not impose any direct compliance requirements on designated facilities, apart from the requirement for States to develop State plans. As explained in section XIV.G., the EG also does not impose specific requirements on Tribal governments that have designated facilities located in their area of Indian country. The burden for States to develop State plans following promulgation of the rule is estimated to be below $100 million in any one year. Thus, the EG is not subject to the requirements of section 203 or section 205 of the UMRA.

The NSPS and EG are also not subject to the requirements of section 203 of UMRA because, as described in 2 U.S.C. 1531–38, they contain no regulatory requirements that might significantly or uniquely affect small governments. The NSPS and EG action imposes no enforceable duty on any State, local, or Tribal governments or the private sector. Specifically, for the EG the State governments to which rule requirements apply are not considered small governments. In light of the interest among governmental entities, the EPA conducted pre-proposal outreach with national organizations representing States and Tribal governmental entities while formulating the proposed rule as discussed in section VII. The EPA considered the stakeholders' experiences and lessons learned to help inform how to better structure this proposal and consider ongoing challenges that will require continued collaboration with stakeholders. With this proposal, the EPA seeks further input from States and Tribes. For public input to be considered during the formal rulemaking, please submit comments on this proposed action to the formal regulatory docket at EPA Docket ID No. EPA–HQ–OAR–2021–0317 so that the EPA may consider those comments during the development of the final rule.

E. Executive Order 13132: Federalism

Under Executive Order 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal Government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or the EPA consults with State and local officials early in the process of developing the proposed action.

The proposed NSPS OOOOb does not have federalism implications. It will not have substantial direct effects on the

States, on the relationship between the Federal Government and the States, or on the distribution of power and responsibilities among the various levels of government.

The proposed EG OOOOc may have federalism implications because development of State plans may entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule, as well as time to work with State legislatures as appropriate, and develop a plan submittal. The Agency understands that the EG may impose a burden on States and is committed to providing aid and guidance to States through the plan development process. In the spirit of E.O. 13132 and consistent with the EPA policy to promote communications between the EPA and State and local governments, the EPA specifically solicits comment on this proposed rule from State and local officials including information on costs associated with developing and submitting State plans in accordance with EG OOOOc.

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

This action has Tribal implications. However, it will neither impose substantial direct compliance costs on Federally recognized Tribal governments, nor preempt Tribal law, and does not have substantial direct effects on the relationship between the Federal Government and Indian Tribes or on the distribution of power and responsibilities between the Federal Government and Indian Tribes, as specified in E.O. 13175. 65 FR 67249 (November 9, 2000). The majority of the designated facilities impacted by proposed NSPS and EG on Tribal lands are owned by private entities, and Tribes will not be directly impacted by the compliance costs associated with this rulemaking. There would only be Tribal implications associated with this rulemaking in the case where a unit is owned by a Tribal government or in the case of the NSPS, a Tribal government is given delegated authority to enforce the rulemaking. Tribes are not required to develop plans to implement the EG under CAA section 111(d) for designated existing sources. The EPA notes that this proposal does not directly impose specific requirements on designated facilities, including those located in Indian country, but before developing any standards for sources on Tribal land, the EPA would consult with leaders from affected Tribes.

Consistent with previous actions affecting the Crude Oil and Natural Gas source category, there is significant Tribal interest because of the growth of the oil and natural gas production in Indian country. Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA will engage in consultation with Tribal officials during the development of this action.

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

This action is subject to E.O. 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by E.O. 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children. GHGs, including methane, contribute to climate change and are emitted in significant quantities by the oil and gas industry. The EPA believes that the GHG emission reductions resulting from implementation of these proposed standards and guidelines, if finalize will further improve children's health. The assessment literature cited in the EPA's 2009 Endangerment Findings concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience. These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More detailed information on the impacts of climate change to human health and welfare is provided in section III of this preamble.

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

This action, which is a significant regulatory action under Executive Order 12866, has a significant adverse effect on the supply, distribution or use of energy. To estimate the potential impacts of the proposed NSPS OOOOb and EG OOOOc on crude oil and natural gas production, the EPA developed a pair of single-market, static partial-equilibrium analyses of national crude oil and natural gas markets. These analyses are presented in the RIA for this action, which is in the public docket. We treat crude oil markets and natural gas markets separately in these models. The EPA estimated that the proposed rule could result in a maximum decrease in annual natural gas production of about 249 million Mcf in 2026 (or about 0.8 percent of natural gas production). We estimated the maximum annual reduction in crude oil production would be about 12.2 million barrels (or about 0.3 percent of crude oil production). Before 2026, the modeled market impacts are much smaller than the 2026 impacts as only the incremental requirements under the proposed NSPS OOOOb are assumed to be in effect. As regulatory costs are projected to decline after 2026, the modelled market impacts for years after 2026 are smaller than the peaks estimated for 2026. As regulatory costs are projected to decline after 2026, the modelled market impacts for years after 2026 are smaller than the peaks estimated for 2026. The energy impacts the EPA estimates from these rules may be under- or over-estimates of the true energy impacts associated with this action. For more information on the estimated energy effects, please refer to the RIA for this rulemaking.

I. National Technology Transfer and Advancement Act (NTTAA)

This proposed action for NSPS OOOOb and EG OOOOc involves technical standards.[350] Therefore, the EPA conducted searches for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute

[350] The EPA is not proposing changes to previously conducted searches for 40 CFR part 60, subparts OOOO and OOOOa. Therefore, this section only describes proposed NSPS OOOOb and EG OOOOc standards and searches.

(ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 18, 21, 22, and 25A of 40 CFR part 60, appendix A. No applicable voluntary consensus standards were identified for EPA Methods 1A, 2A, 2D, 21, and 22 and none were brought to its attention in comments. All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for this rule. Two VCS were identified as an acceptable alternative to EPA test methods for the purpose of this proposed rule. First, ANSI/ASME PTC 19–10–1981, Flue and Exhaust Gas Analyses (Part 10) (manual portions only and not the instrumental portion) was identified to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A and 16A. This standard includes manual and instructional methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and sulfur dioxide. Second, ASTM D6420–99 (2010), ''Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry'' is an acceptable alternative to EPA Method 18 with the following caveats, only use when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable. ASTM D6420 should never be specified as a total VOC Method. (ASTM D6420–99 (2010) is not incorporated by reference in 40 CFR part 60.) The search identified 19 VCS that were potentially applicable for this proposed rule in lieu of EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data and other important technical and policy considerations. For additional information, please see the September 10, 2021, memo titled, ''Voluntary Consensus Standard Results for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review'' in the public docket. The EPA plans to propose the regulatory language for NSPS OOOOb and EG OOOOc through a supplemental action. At that time, the EPA will include any appropriate incorporation by reference in accordance with requirements of 1 CFR 51.5 as discussed below. The EPA anticipates that the following ten standards would be incorporated by reference.

- ASTM D86–96, Distillation of Petroleum Products (Approved April 10, 1996) covers the distillation of natural gasolines, motor gasolines, aviation gasolines, aviation turbine fuels, special boiling point spirits, naphthas, white spirit, kerosines, gas oils, distillate fuel oils, and similar petroleum products, utilizing either manual or automated equipment.
- ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography covers the determination of the chemical composition of natural gases and similar gaseous mixtures within a certain range of composition. This test method may be abbreviated for the analysis of lean natural gases containing negligible amounts of hexanes and higher hydrocarbons, or for the determination of one or more components.
- ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuel covers procedures for calculating heating value, relative density, and compressibility factor at base conditions for natural gas mixtures from compositional analysis. It applies to all common types of utility gaseous fuels.
- ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion covers the determination of the heating value of natural gases and similar gaseous mixtures within a certain range of composition.
- ASTM D6522–00 (Reapproved December 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers covers the determination of nitrogen oxides, carbon monoxide, and oxygen concentrations in controlled and uncontrolled emissions from natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters.
- ASTM E168–92, General Techniques of Infrared Quantitative Analysis covers the techniques most often used in infrared quantitative analysis. Practices associated with the collection and analysis of data on a computer are included as well as practices that do not use a computer.
- ASTM E169–93, General Techniques of Ultraviolet Quantitative Analysis (Approved May 15, 1993) provide general information on the techniques most often used in ultraviolet and visible quantitative analysis. The purpose is to render unnecessary the repetition of these descriptions of techniques in individual methods for quantitative analysis.
- ASTM E260–96, General Gas Chromatography Procedures (Approved April 10, 1996) is a general guide to the application of gas chromatography with packed columns for the separation and analysis of vaporizable or gaseous organic and inorganic mixtures and as a reference for the writing and reporting of gas chromatography methods.
- ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus] (Issued August 31, 1981) covers measuring the oxygen or carbon dioxide content of the exhaust gas.
- EPA–600/R–12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (Issued May 2012) is mandatory for certifying the calibration gases being used for the calibration and audit of ambient air quality analyzers and continuous emission monitors that are required by numerous parts of the CFR.

The EPA determined that the ASTM and ASME/ANSI standards, notwithstanding the age of the standards, are reasonably available because it they are available for purchase from the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106 and the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990. The EPA determined that the EPA standard is reasonably available because it is publicly available through the EPA's website: *http://nepis.epa.gov/Adobe/PDF/P100EKJR.pdf.*

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

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). The documentation for this decision is contained in the RIA prepared under E.O. 12866 for this proposal. In Section 4 of the RIA, the EPA presents a qualitative discussion of the climate impacts of GHGs and environmental justice. The section also presents a set of limited quantitative environmental justice analyses focused on the current distribution of VOC and HAP emissions from oil and natural gas sector. These analyses evaluated baseline scenarios

and enabled us to characterize risks due to oil and natural gas VOC and HAP emissions prior to implementation of the proposed rule. These analyses potentially suggest that VOC and HAP emissions from the oil and natural gas sector may disproportionately impact vulnerable populations or overburdened communities under baseline scenarios; however, various uncertainties and data gaps remain, and should be taken into consideration when interpreting these results. Additionally, we lack key information that would be needed to characterize post-control risks under the proposed NSPS OOOOb and EG OOOOc or the regulatory alternatives analyzed in the RIA, preventing the EPA from analyzing spatially differentiated outcomes. While a definitive assessment of the impacts of this proposed rule on minority populations, low-income populations, and/or indigenous peoples was not performed, the EPA believes that this action will achieve substantial methane, VOC, and HAP emission reductions and will further improve environmental justice community health and welfare. The EPA believes that any potential environmental justice populations that may experience disproportionate impacts in the baseline may realize disproportionate improvements in air quality resulting from emission reductions.

In addition, the EPA provided the public, including those communities disproportionately impacted by the burdens of pollution, opportunities for meaningful engagement with the EPA on this action. A summary of outreach activities conducted by the Agency and what we heard from communities is provided in section VI of this preamble.

List of Subjects in 40 CFR Part 60

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

Michael S. Regan,

Administrator.

[FR Doc. 2021–24202 Filed 11–5–21; 4:15 pm]

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Part III

Department of Transportation

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments; Final Rule

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2011–0023; Amdt. Nos. 191–30; 192–129]

RIN 2137–AF38

Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas gathering pipelines. This final rule addresses Congressional mandates, Government Accountability Office recommendations, and public input received as part of the rulemaking process. The amendments in this final rule extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. The rule does not affect offshore gas gathering pipelines.

DATES: The effective date of this final rule is May 16, 2022. The Director of the Federal Register approved the incorporation by reference of certain material listed in this rule as of April 14, 2006.

FOR FURTHER INFORMATION CONTACT:

Technical questions: Steve Nanney, Project Manager, by telephone at 713–272–2855.

General information: Sayler Palabrica, Transportation Specialist, by telephone at 202–366–0559.

SUPPLEMENTARY INFORMATION:

I. Executive Summary
- A. Purpose of the Regulatory Action
- B. Summary of the Major Provisions of the Regulatory Action
- C. Costs and Benefits

II. Background
- A. Detailed Overview
- B. Advance Notice of Proposed Rulemaking
- C. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011
- D. Government Accountability Office (GAO) Recommendations
- E. Notice of Proposed Rulemaking
- F. Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020

III. Analysis of NPRM Comments, GPAC Recommendations, and PHMSA Response
- A. Reporting Requirements—§§ 191.1, 192.5, 191.17, and 191.29
- B. Gathering Line Definitions—§§ 192.3 and 192.8
- C. Expanded Scope of Gas Gathering Line Regulations—§ 192.8
- D. Safety Requirements for Newly Regulated Gas Gathering Lines—§§ 192.9, 192.13, 192.18, 192.452, and 192.619

IV. Section-By-Section Analysis

V. Availability of Standards Incorporated-by-Reference

VI. Regulatory Analysis and Notices

I. Executive Summary

A. Purpose of the Final Rule

This final rule responds to Government Accountability Office (GAO) recommendations and a Congressional mandate by extending existing design, operational and maintenance, and reporting requirements under the Federal Pipeline Safety Regulations to onshore natural gas gathering pipelines (''gathering lines'') in rural areas. Increasingly, many of these gathering lines have design and operating parameters that are similar to natural gas transmission lines (''transmission lines''), which pose an increased risk to public safety and the environment. PHMSA expects the regulatory amendments in this final rule will reduce the frequency and consequences of failures of onshore gas gathering lines and in turn reduce the likelihood of gas-related releases and incidents. The requirements in the final rule are designed to prevent and detect threats to pipeline integrity, improve public awareness of pipeline safety, and improve emergency response to pipeline incidents. PHMSA expects this final rule, therefore, will (1) improve public safety; (2) reduce threats to the physical environment (including, but not limited to, greenhouse gas emissions released during natural gas gathering line incidents); and (3) promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities.

Gas gathering lines are pipelines used to transport natural gas from a current production facility to a transmission line or distribution main lines (''main lines''). Generally, these pipelines are used to collect unprocessed gas from production facilities for transport to a gas treatment plant or other facility. From there, the natural gas is separated from petroleum liquids, water, and other impurities to prepare the gas for further transportation and sale. In the Federal Pipeline Safety Regulations (49 Code of Federal Regulations (CFR) parts 190 through 199), gas gathering lines are distinct from gas transmission pipelines which are defined in § 192.3 as pipelines that: (1) Transport gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center; (2) operate at a hoop stress of 20 percent or more of specified minimum yield strength (SMYS); [1] or (3) transport gas within a storage field.

Section 192.5 divides gas transmission and gathering lines into class locations based on the number of dwellings near the pipeline. These range from rural Class 1 to densely populated Class 4 locations. Class locations are defined in § 192.5. A Class 1 location is an offshore pipeline or an onshore pipeline that has 10 or fewer buildings intended for human occupancy within a 1-mile-long class-location unit. Unlike transmission lines, which are regulated regardless of location, gathering lines in rural Class 1 locations are exempt from Federal pipeline safety and reporting regulations in parts 191 and 192. However, PHMSA has authority under 49 U.S.C. 60102(a)(2) to issue safety regulations for pipeline transportation and pipeline facilities, including non-rural gathering lines and rural gathering lines designated by the Secretary as ''regulated gathering lines'' under 49 U.S.C. 60101(a)(21) and (b). Section 60117(b)(2) also authorizes DOT to require owners and operators of gathering lines, including rural gathering lines that have not been defined as regulated gathering lines, to submit information pertinent to its ability to make a determination as to whether and to what extent to regulate gathering lines.

Prior to 2005, U.S. gas production had been stagnant since a peak in the early 1970s.[2] The gathering lines that received gas from conventional wells typically had smaller diameters than gas transmission lines and operated at lower pressures. All else equal, a smaller diameter and lower pressure pipeline will release less gas and energy during an incident compared with a larger diameter pipeline with a greater operating pressure, such as a major transmission line. As a result, gathering lines located in Class 1 locations were

[1] SMYS is defined in § 192.3 and refers to the minimum force required to deform permanently the material as specified in the applicable design codes.

[2] *See* U.S. Energy Information Administration (EIA), ''Natural Gas Explained—U.S. natural gas consumption, dry production, and net imports, 1950–2019,'' *https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php* (accessed Nov. 3, 2020).

thought to pose relatively low risk to the public and the environment; therefore, gathering lines in Class 1 locations were exempt from reporting and safety requirements in the Federal Pipeline Safety Regulations. On the other hand, to account for the risks related to their physical, functional, and operational characteristics, transmission pipelines have been subject to PHMSA regulations regardless of their location.

Regardless of their size, regulated gathering lines are required to comply with safety reporting requirements and minimum safety standards in parts 191 and 192. Section 192.8(b) currently provides for two categories of regulated onshore gathering lines. Type A gathering lines are located in Class 2, Class 3, or Class 4 locations (see § 192.5) that operate at relatively higher stress levels. Section 192.9(c) subjects Type A regulated gathering lines to the same requirements as gas transmission pipelines, with a few exceptions, due to the high potential consequences of an incident on a high-stress pipeline in a populated area. Type B gathering lines are lower-stress pipelines in Class 3, Class 4, and certain Class 2 locations. Section 192.9(d) subjects Type B to a less comprehensive set of requirements since such pipelines operate at lower stress levels than transmission pipelines. As stated above, gathering lines in Class 1 locations are excluded from the reporting and safety standards contained in parts 191 and 192. In a 2006 final rule, PHMSA determined that the potential consequences of a release of a smaller-diameter pipeline with a lower maximum allowable operating pressure (''MAOP''), in a sparsely populated area, would be minimal.[3]

Due to new drilling technologies and changing demand factors, domestic gas production has been surging since approximately 2006.[4] Besides larger overall production volumes, new drilling technologies have also greatly increased the volume of gas that can be extracted from a single production site.[5] As a result, the volume of gas transported by gathering lines have also increased significantly. In order to transport this additional volume, some gas gathering lines are now constructed with large-diameter pipe and operating pressures comparable to large, interstate gas transmission pipelines. For example, the National Association of State Pipeline Safety Representatives (NAPSR)[6] Resolution 2010–2 AC–2 notes that members have observed rural gathering lines as large as 30 inches in diameter with a MAOP as high as 1480 psi.[7] The potential safety and environmental consequences of a gas pipeline rupture are proportional to the pipeline's diameter and operating pressure. Large diameter gathering lines are still exempt from the requirements in parts 191 and 192 if they are located in Class 1 locations despite their physical and functional similarities with transmission pipelines and their increased potential for adverse consequences in the event of incident.

Large diameter, high-pressure gathering lines are susceptible to the same types of integrity threats as transmission pipelines, including corrosion, excavation damage, and construction defects. The exemption of these pipelines from the safety requirements of the Federal Pipeline Safety Regulations failed to consider the present risks that now exist. In addition, PHMSA has lacked detailed information on the safety of gas gathering lines in Class 1 locations because such lines have been exempted from requirements to submit incident and annual reports under part 191. These reports are necessary for PHMSA to analyze how recent changes in the gas production and midstream industries affect the functional and operational characteristics of unregulated gathering lines, and the safety consequences of those changes. While more comprehensive information is being collected and analyzed, expanded regulatory measures are needed to protect the human and natural environment from the consequences of incidents on large-diameter, high-pressure gathering lines from preventable causes such as corrosion, excavation damage, and inadequate design and construction practices.

On August 25, 2011, PHMSA issued an advance notice of proposed rulemaking (ANPRM) that, among other things, requested comments with respect to improving the regulation of gas gathering lines.[8] Following the ANPRM's publication, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act, Pub. L. 112–90) was enacted on January 3, 2012. Section 21 of the 2011 Pipeline Safety Act mandated that DOT review existing regulations for gathering lines and report to Congress on the sufficiency of existing Federal and State laws and the need to modify or revoke existing exemptions from Federal regulation for gathering lines.

Subsequently, in 2012, the GAO issued recommendation GAO–12–388 for PHMSA to collect data on Federally unregulated hazardous liquid and gas gathering lines.[9] In August 2014, GAO issued recommendation 14–667 for PHMSA to ''move forward with rulemaking to address gathering pipeline safety that addresses the risks of larger-diameter, higher-pressure gathering pipelines, including subjecting such pipelines to emergency response planning requirements that currently do not apply to gathering pipelines.''[10]

On April 8, 2016, PHMSA issued a notice of proposed rulemaking (NPRM) responding to comments received on the ANPRM and proposing to further regulate gas gathering lines to enhance safety.[11] This final rule addresses only those portions of the NPRM dealing with gas gathering lines. Portions of the NPRM dealing with gas transmission issues have already been implemented in the final rule, ''Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments,'' (''Gas Transmission Final Rule'') published on October 1, 2019.[12] The remaining gas transmission issues will be addressed in the future in a separate rulemaking under the Regulatory Identifier Number (RIN) 2137–AF39, titled ''Pipeline Safety: Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments.''

The NPRM discussed the Congressional mandate and GAO recommendations, as well as the increased risk factors regarding gathering lines discussed above. In addition, the NPRM explained the need to clarify the definitions of gas gathering lines in §§ 192.3 and 192.8, which rely on American Petroleum Institute (API) Recommended Practice (RP) 80,

[3] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 FR 13289, 13291 (Mar. 15, 2006).

[4] EIA, ''U.S. Natural Gas Marketed Production,'' *https://www.eia.gov/dnav/ng/hist/n9050us2a.htm.* (accessed Nov. 9, 2020).

[5] EIA, ''Hydraulically fractured horizontal wells account for most new oil and natural gas wells,'' *https://www.eia.gov/todayinenergy/detail.php?id=34732* (Jan. 30, 2018).

[6] NAPSR is a nonprofit association of State pipeline safety officials.

[7] Available on the NAPSR website at *http://www.napsr.org/resolutions.html.*

[8] Pipeline Safety: Safety of Gas Transmission Pipelines, 76 FR 53086.

[9] GAO, No. 12–388, ''Pipeline Safety: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety'' (Mar. 22, 2012).

[10] GAO, No. 14–667, ''Oil and Gas Transportation: Department of Transportation Is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety'' at 48 (Aug. 2014).

[11] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 FR 20722.

[12] 84 FR 52180.

''Guidelines for the Definition of Onshore Gas Gathering Lines,'' first edition, April 2000. The current definitions are unclear with respect to each of (1) the point at which a non-jurisdictional production operation ends and a potentially regulated gas gathering line begins and (2) the use of the incidental gathering designation, which allows an operator to designate lines downstream from any gathering function defined in API RP 80 as a gathering line rather than as a transmission line.

A summary of the proposed changes and PHMSA's response to the comments on the NPRM are provided below in section III of this final rule.

On December 28, 2020, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (2020 PIPES Act, Pub. L. 116–260) was enacted. Section 112(a) directed PHMSA to issue a final rule in this rulemaking by March 27, 2021.

B. Summary of the Major Provisions of the Final Rule

This final rule addresses reporting and safety requirements for onshore gas gathering lines; offshore gas gathering lines are beyond the scope of this rulemaking.[13] The final rule requires operators of all onshore gas gathering lines to report incidents and file annual reports under part 191. The purpose of this expanded reporting obligation is to gather data about the state of gas gathering infrastructure and monitor the safety performance of gas gathering lines that were previously exempt from Federal reporting requirements. The information in the reports will help determine the need for future regulatory changes to address the risks to the public, property, and the environment posed by all types of pipeline systems engaged in the transportation of gas.

In addition, the final rule provides for a new Type C regulated gathering line[14] in § 192.8. Type C gathering lines are defined as gas gathering lines in Class 1 locations that have outer diameters of 8.625 inches or greater and operate at higher stress levels or pressures. The safety requirements for Type C lines, referred to as Type C requirements in the final rule, are specified in revised § 192.9(e) and vary based on the outer diameter of the pipeline and the potential consequences of a failure. The potential consequences of incidents are greater on larger-diameter, higher-pressure pipelines and pipelines that are located near buildings intended for human occupancy. Type C gathering lines with an outside diameter greater than 16 inches and certain other Type C gathering lines that could directly affect homes and other structures are required to comply with (1) existing requirements for Type B gas gathering lines, and (2) requirements at § 192.615 that operators develop and implement emergency plans. Type C gathering lines with smaller diameters or that could not directly affect homes and other structures have fewer requirements that are limited to damage prevention, emergency plans, and public awareness. These requirements address known causes of pipeline failures including excavation damage, corrosion, and inadequate design and construction standards.

C. Costs and Benefits

Consistent with 49 U.S.C. 60102(b) and Executive Order 12866 (''Regulatory Planning and Review''),[15] PHMSA has prepared an assessment of the benefits (including safety and environmental benefits) and costs of the final rule as well as reasonable alternatives. PHMSA expects benefits of the final rule to consist of improved safety and avoided environmental harms (including methane emissions) from reduction of the frequency and consequences of failures of onshore natural gas gathering lines that could result in releases and incidents. PHMSA estimates the annualized costs of the rule to be approximately $13.7 million per year at a 7-percent discount rate. The Regulatory Impact Analysis (RIA) for this final rule is available in the docket. The table below provides a summary of the estimated costs for the major provisions in this rulemaking and in total (see the RIA for further detail on these estimates).

Provision	Estimated annualized cost (7%)
Right-of-Way Surveillance	$170,087.
Corrosion Control	$2,043,260.
Damage Prevention	$285,011.
Public Awareness	$550,464.
Line Markers	$1,680,870.
Emergency Plan	$312,167.
Leakage Surveys	$7,626,075.
Incident reporting	$134,556.
Annual reporting	$943,408.
Construction	Negligible.
Total	$13,745,898.

II. Background

A. Detailed Overview

Introduction

The Pipeline Safety Regulations divide gas transmission and gathering lines into classes from Class 1 (rural areas) to Class 4 (densely populated, high-rise areas) that are based on the number of buildings or dwellings for human occupancy in the area. Class locations are defined in § 192.5. A Class 1 location is an offshore pipeline or an onshore pipeline that has 10 or fewer buildings intended for human occupancy within a 1-mile-long class-location unit. This final rule addresses only onshore gas gathering lines. Gas gathering lines located in Class 2, Class 3, and Class 4 locations have been subject to reporting requirements in part 191 and safety requirements in part 192. Type A lines, which operate at higher pressure, are required to comply with most safety requirements applicable to transmission pipelines at part 192, while lower-pressure Type B lines are required to follow fewer requirements, which are listed in § 192.9(d).

When PHMSA last issued regulations addressing the safety of gas gathering lines in 2006,[16] it exempted gathering lines in Class 1 locations from reporting and safety requirements in parts 191 and 192. At the time, such pipelines were mostly small-diameter, low-pressure pipelines located in sparsely populated, traditional oil-producing regions and were thought to pose relatively low risks to the public. However, by the time that the 2006 final rule was adopted, innovative drilling technologies, new hydrocarbon discoveries, and increasing demand for natural gas were starting to transform the industry. Highly productive ''unconventional'' drilling techniques have proliferated, and modern production sites can be several times more productive than conventional wells. The characteristics of the gathering lines servicing current wells often have more in common with large interstate transmission systems than the diffuse network of small gathering lines that predominated when the current gas

[13] References in this final rule to ''gathering'' therefore refer, unless specified otherwise, to onshore gas gathering pipelines. Similar to Type A onshore gas gathering lines, offshore gas gathering lines are already covered by the requirements in part 192 applicable to transmission lines, with some exceptions listed in § 192.9(b).

[14] This final rule and amended regulatory text use the formulation ''Type C'' to identify the newly-regulated onshore gathering lines described in the NPRM as ''Type A, Area 2.'' However, in discussion of the NPRM and comments thereon, this final rule will use the formulation ''Type A, Area 2'' for the convenience of the reader.

[15] 58 FR 51375 (Oct. 4, 1993).

[16] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 FR 13289 (Mar. 15, 2006).

gathering regulatory framework was being developed prior to 2006. These changes are placing unprecedented demands and increasing safety risks on the Nation's pipeline system.

The final rule requires operators of all onshore gas gathering lines to prepare and submit annual reports with information about their gas gathering lines and to submit incident reports under part 191. The information is necessary to monitor the safety performance of gas gathering systems and inform the appropriate level of regulatory oversight. This final rule also adopts new safety requirements for larger-diameter (*i.e.,* with outer diameters of 8.625 inches or greater), higher-operating pressure gas gathering lines to mitigate risks to public safety and pipeline integrity. The need to implement risk-based protections and build an understanding of the safety of gas gathering systems is critical since ''unconventional'' production operations continue to expand, often into regions inexperienced with oil and gas development—posing new risks to humans and the environment.

Natural Gas Gathering Infrastructure Overview

The U.S. natural gas pipeline network is designed to transport natural gas to and from most locations in the country. Approximately two-thirds of the lower 48 States depend almost entirely on the interstate transmission pipeline system for their supplies of natural gas.[17] In 49 CFR part 192, pipelines are classified into three broad groups, based on their function and characteristics: Gathering, transmission, and distribution systems. Onshore gathering lines, the sole subject of this final rule, typically transport gas from production fields to gas transmission pipelines or centralized processing and storage facilities. From there, gas is typically transported to large industrial users such as gas-fired power stations or local distribution companies via transmission pipelines. Finally, distribution companies deliver gas to homes and businesses, and other end-users. Together, these systems form an interconnected network that transports natural gas from the production field to its end users. PHMSA estimates that there are over 400,000 miles of onshore gas gathering lines throughout the U.S., the vast majority of which are in Class 1 locations.[18]

Regulatory History

The Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90–481) vested the Secretary with statutory authority to issue regulations to ensure the safe transportation of natural gas by pipeline but excluded the regulation of gas gathering lines in rural areas, which were defined in section 2(3) of the 1968 Act as those locations outside the limits of any incorporated or unincorporated city, town, or village, or other designated residential or commercial area. Later, Congress modified the definition of ''transporting gas'' to provide Secretary the authority to designate non-rural areas in order to make pipelines in those non-rural areas subject to PHMSA's jurisdiction (49 U.S.C. 60101(a)(21)(B)).

PHMSA,[19] through delegation by the Secretary,[20] and its State partners enforce requirements for regulated [21] gas gathering systems in the Federal Pipeline Safety Regulations that are authorized under 49 U.S.C. 60101 *et seq.* DOT issued interim minimum Federal safety standard regulations for gas pipeline facilities and the transportation of natural and other gas by pipeline on November 13, 1968,[22] and subsequently codified broad-based gas pipeline regulations in 49 CFR part 192 on August 19, 1970.[23] The 1970 final rule defined a ''gathering line'' as ''a pipeline that transports gas from a current production facility to a transmission line or main,'' and subjected all gathering lines located in non-rural areas (*e.g.,* within the limits of any incorporated or unincorporated city, town, or village, or other designated residential or commercial area) to all requirements applicable to transmission pipelines (§§ 192.1 and 192.9).

This historical approach to defining PHMSA's jurisdiction, however, has left several key gaps which made it difficult to determine where a gathering line started and ended. One was that it failed to define ''current production facility,'' and therefore the point where a non-jurisdictional production facility became a gathering line was not clear.[24] Additionally, there was no clear definition of where a gathering line ended, and a transmission pipeline or distribution main line began. The DOT has attempted to clarify these gaps several times. In 1974, DOT proposed to revise the definition of a gas ''gathering line'' to address this uncertainty as to the beginning and end points of gas gathering.[25] However, the proposal was later withdrawn.[26]

In 1991, DOT again proposed to revise the definition of a gathering line following a NAPSR survey of its members noting ongoing disagreements about the classification of certain segments of gas pipelines.[27] However, in response to comments on the proposed rule and the issuance of the Pipeline Safety Act of 1992 (Pub. L. 102–508), PHMSA delayed final action on that proposal to consider additional information and the statutory changes. As described earlier, PHMSA was previously restricted from issuing regulations for rural gathering lines. Section 109 of The Pipeline Safety Act of 1992 expanded DOT's authority by authorizing the Secretary to define the term ''regulated gathering line,'' and issue safety regulations for the transportation of gas through those pipelines despite their location in rural areas (49 U.S.C. 60101(b)). The Pipeline Safety Act of 1992 also directed DOT to consider functional and operational characteristics in defining gathering lines (49 U.S.C. 60101(b)(1)(B)(i)). For the definition of the term ''regulated gathering line,'' Congress further directed DOT to consider such factors as location, length of line from the well site, operating pressure, throughput, and gas composition in deciding which gathering lines are functionally gathering yet warrant regulation as regulated gathering lines (49 U.S.C. 60101(b)(2)(A)). This authority also expressly allowed DOT to depart from the concepts used to define gathering for the purposes of determining the scope of the Federal Energy Regulatory

[17] U.S. Department of Energy (DOE), ''Appendix B: Natural Gas—Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure'' p. NG–28 (Apr. 2015).

[18] API estimated there were 240,000 miles of unregulated gathering lines in comments submitted October 23, 2012, available in the docket. In order to project an estimate of gathering lines in service today, PHMSA adjusted this estimate based on average rate of increase in reported mileage of regulated gathering lines from operators' annual reports since 2012. *See* the RIA, available in the docket, for additional information on estimates of gathering miles affected by the rule.

[19] PHMSA's predecessor agencies include the Research and Special Programs Administration (RSPA), the Materials Transportation Bureau (MTB), and the Office of Pipeline Safety (OPS). For simplicity, all are referred to as DOT in this section.

[20] 49 CFR 1.97.

[21] Typically, onshore pipelines involved in the ''transportation of gas,'' *see* 49 CFR 192.1 and 192.3 for detailed applicability.

[22] Interim Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline, 33 FR 16500.

[23] Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, 35 FR 13248.

[24] Transportation of Natural and Other Gas by Pipeline: Proposed Definition of Gathering Line, 39 FR 34569 (Sept. 26, 1974).

[25] Id.

[26] Transportation of Natural and Other Gas by Pipeline: Withdrawal of Proposed Definition of Gathering Line, 43 FR 42773 (Sept. 21, 1978).

[27] Gas Gathering Line Definition: Notice of Proposed Rulemaking, 56 FR 48505 (Sept. 25, 1991).

Commission's (FERC) authority under the Natural Gas Act (15 U.S.C. 717 *et seq.*) in order to define gas gathering lines based on functional, rather than rate-setting, considerations. In other words, whether the DOT classifies a pipeline as a transmission line, gathering line, or regulated gathering line has no impact on the pipeline's status with FERC and vice-versa.

In 1999, PHMSA renewed the effort to define gathering lines. To facilitate this project, PHMSA opened a website for public discussion on the question of how to define gas gathering lines and whether there was a need to subject rural gathering lines to Federal safety oversight.[28] The majority of the comments received focused on the work that was being done by API to classify gathering lines. That effort culminated in the publication of the first edition of API RP 80 in April 2000.

The purpose of API RP 80 is to define gas gathering lines in onshore areas based on the line's function. It distinguishes a gathering function from a ''production operation'' that is not engaged in transportation (see section 2.3 of API RP 80) and defines a number of points that determine the potential endpoint of the gathering function (see section 2.2(a)(1)(A) through (a)(1)(D) of API RP 80), such as the inlet to the furthermost downstream gas processing plant or the furthermost downstream point where gas produced in the same production field or separate production fields is commingled. API RP 80 defines a gathering line as ''a pipeline, or a connected series of pipelines, used to transport gas from the furthermost downstream point in a production operation to the furthermost downstream of one of the defined endpoints of gathering.'' The document also includes supplementary definitions, discussion, and diagrams to provide additional guidance on how operators may apply these definitions to various types of gathering systems. Section 192.8 includes limitations on how aspects of API RP 80 must be applied.

Ever since API RP 80 was first issued, PHMSA has had concerns about ''incidental gathering.'' While section 2.2(a)(1)(A) through (a)(1)(D) describe points where the gathering function can end, paragraph (a)(1)(E) allows an operator to designate pipeline segments that are past the furthermost downstream of the other endpoint of gathering up to the connection to ''another pipeline'' (typically a transmission line) as a gathering line regardless of the actual function or operational characteristics of the pipeline itself. This is the ''incidental gathering'' concept discussed in API RP 80 section 2.2.1.2.6. By definition, these lines extend beyond the end of any gathering functions. When a major gas processing plant or a compressor used to raise the pressure for delivery into a transmission line is the endpoint, the incidental gathering line segment can be indistinguishable from a transmission line in terms of its function, diameter, pressure, and gas composition; yet is treated as a gathering line rather than a transmission line under part 192. Additionally, there are no limits on how far an incidental gathering line may extend under the API RP 80 definition. The API RP 80 concept of ''incidental gathering'' undermines the functional definition of ''gathering'' that API RP 80 was intended to establish. In fact, API RP 80 creates a regulatory gap for pipeline segments that bear the least functional and operational resemblance to gathering lines.

In 2003, DOT held public meetings in Austin, Texas, and Anchorage, Alaska, to determine the best way to define the terms ''gas gathering line'' and ''regulated gathering line'' and what, if any, safety rules would be needed for rural regulated gathering lines.[29] At the meetings, DOT proffered a ''sliding corridor'' concept as a possible basis for defining which gathering lines should be designated as regulated gathering lines. This concept was similar to the ''sliding mile'' used for class location determinations, except that the corridor would be 1,000 feet long rather than one mile, and the width would vary depending on the stress level of the segment of pipe. Wherever the corridor contained five or more dwellings, the gathering line segment would be subject to a subset of Federal Pipeline Safety Regulations, the scope of which would increase as the stress level [30] of the segment increased.

After these two meetings, DOT published a document that stated that the definitions of production and gathering should ensure that Federal regulation of gathering lines does not overlap with State regulations on production, and should promote consistent application by regulators and operators.[31] The document invited comments on an appropriate approach for identifying rural gas gathering lines that warranted regulation. After the 2003 public meetings, DOT met several times with State agency officials, industry representatives, and others to obtain different views on the risks posed by gas gathering lines and the need for Federal regulation over the same.

In 2006, DOT published a final rule that established the current Federal Pipeline Safety Regulations for gas gathering lines in §§ 192.8 and 192.9.[32] The final rule incorporated by reference API RP 80, which defines ''onshore gas gathering pipelines.'' The 2006 final rule also replaced the previous ''non-rural'' criteria for designating regulated gathering lines in § 192.9 with a risk-based approach to regulating gas gathering lines in Class 2, 3, and 4 locations. In the 2006 final rule, PHMSA chose not to extend any reporting or safety requirements to gas gathering lines in Class 1 locations. At the time, PHMSA noted that such pipelines were typically small-diameter, low-pressure lines posing relatively low risks to the public. The Federal requirements for gas gathering lines have remained in place, mostly unchanged, since 2006.

Supply Changes

Between 2005 and 2019, marketed production of natural gas increased from 18.9 trillion cubic feet (Tcf) per year to 36.5 Tcf per year.[33] While gross gas production from conventional wells has fallen by 53 percent from 16.2 Tcf per year to 7.6 Tcf per year between 2005 and 2019,[34] overall production has grown due to increased unconventional shale gas production. EIA began reporting shale gas well withdrawals in 2007. In 2007, unconventional shale gas accounted for about 8 percent of the total natural gas production in the U.S. Since then, shale gas production has increased from 1.9 trillion cubic feet per year to 27.8 trillion cubic feet per year in 2019 [35] and now accounts for

[28] Request for Comments: Gas Gathering Line Definition, 64 FR 12147 (Mar. 11, 1999).

[29] *See* 68 FR 62555 (Nov. 5, 2003) (Austin, TX, meeting) and 68 FR 67129 (Dec. 1, 2003) (Anchorage, AK, meeting). Transcripts for the meeting are available for download at *regulations.gov* under Docket No. PHMSA–RSPA–1998–4868.

[30] Expressed as the circumferential fore on a pipe (hoop stress) produced by the MAOP as a percent of the specified minimum yield strength (SMYS). SMYS is defined in § 192.3 and refers to the minimum force required to deform permanently the material as specified in the applicable design codes.

[31] Gas and Hazardous Liquid Gathering Lines: Clarification of Rulemaking Intentions and Extension of Time for Comments, 69 FR 5305 (Feb. 4, 2004).

[32] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 FR 13289 (Mar. 15, 2006).

[33] EIA, ''U.S. Natural Gas Marketed Production,'' *https://www.eia.gov/dnav/ng/hist/n9050us2a.htm* (accessed Nov. 9, 2020).

[34] EIA, ''U.S. Natural Gas Gross Withdrawals from Gas Wells,'' *https://www.eia.gov/dnav/ng/hist/n9011us2a.htm* (accessed Nov. 9, 2020).

[35] EIA, ''U.S. Natural Gas Gross Withdrawals from Shale Gas,'' *https://www.eia.gov/dnav/ng/hist/ngm_epg0_fgs_nus_mmcfa.htm* (accessed Nov. 9, 2020).

approximately 68 percent of overall gross gas production.

This increase in unconventional gas extraction has shifted production from traditional gas producing regions such as Texas, Louisiana, Oklahoma, and the Gulf of Mexico to other areas, such as Pennsylvania and Ohio. For instance, in 2001, 5,066,015 million cubic feet (MMcf) of natural gas was withdrawn from the Gulf of Mexico, which was approximately 21 percent of the Nation's natural gas gross production. By 2019, withdrawals decreased to 1,033,922 MMcf. During that same period, Pennsylvania's share of production grew from 130,853 MMcf to 6,896,792 MMcf.[36] The Department of Energy projects that more than half of increases in shale gas production through 2050 will occur in the Appalachian Basin (*e.g.,* the Marcellus and Utica Basins), which will continue to fuel growth in natural gas production from the 2020 levels of 33.9 t (Tcf) per year to 43.0 Tcf per year in 2050.[37]

Demand Changes

Increased production of natural gas in the United States has depressed average prices and volatility.[38] In 2004, the growth outlook for natural gas production was weak; the EIA forecasted that dry gas production would increase by only 1.0 percent annually [39] and that production in the lower 48 would be 21.3 Tcf per year by 2025, or up to 25.1 Tcf per year in the rapid technology scenario.[40] At the time, monthly average spot prices at Henry Hub [41] were high, based on historic comparison of prices, fluctuating between $4 per million British thermal units (Btu) and $7 per million Btu. Prices rose above $11 per million Btu for several months in both 2005 and 2008.[42] Since then, after production shifted to onshore unconventional shale resources and price volatility decreased since 2009, natural gas has frequently traded between $2 and $4 per million Btu, and the spot price has not been above $6 per million Btu for any full month.[43]

This fall in natural gas prices and volatility was accompanied by significant demand growth and changes to the geography of gas demand. Low fuel costs, improved gas turbine technology, operational advantages, and greenhouse gas concerns have driven a steady growth in gas-fired electricity generation. According to the Department of Energy, natural gas surpassed coal as the fuel with the highest share of net electricity generation in 2016.[44] Natural gas exports have also increased. In 2019, the U.S. exported 4.7 Tcf of gas, over six times the amount that was exported in 2006.[45] Virtually all the gas produced and consumed in the U.S. is transported by gas gathering and transmission pipelines to distribution pipelines or end-users.

Consequences for Gas Gathering

Modern production techniques, higher production volumes, and the geography of new gas discoveries have had consequences for gas gathering systems that PHMSA did not contemplate in 2006. Individual unconventional wells can be several times more productive than conventional facilities, and multiple wells can be drilled from a single wellpad, resulting in a large increase in the volume of gas that can flow from production and gathering lines serving a single site. In addition, these productivity gains have led to a surge in production overall, which expands the demands placed on the overall gas gathering pipeline network. Modern gas gathering lines often bear a closer resemblance to large interstate transmission lines than the diffuse network of small, low-pressure lines that previously characterized gathering lines. An incident on such pipelines can have serious consequences, even in a Class 1 location.

Although PHMSA has not collected annual report information on the mileage or diameter of gas gathering lines in Class 1 locations, various stakeholders have reported significant growth in large-diameter, high-pressure gas gathering lines operating outside the scope of the Federal Pipeline Safety Regulations. NAPSR noted in the preamble to its Resolution 2010–2 AC–2 that ''it is not uncommon to find rural gas gathering pipelines up to 30 inches in diameter and operating at a MAOP of 1480 psi [pounds per square inch, or approximately 1495 pounds per square inch gauge (psig)]'' in modern gas gathering systems,[46] which resembles the operational characteristics of major interstate transmission pipelines that are subject to part 191 and 192 regardless of where they are located. Similarly, the GAO noted that 24-inch diameter unregulated gathering lines were located and constructed in close proximity to homes in Pennsylvania, and 30 to 36-inch diameter unregulated gas gathering lines were planned for construction in the Eagle Ford shale formation in Texas.[47] In comments to the NPRM, the Pennsylvania Public Utility Commission noted that producers in the State are constructing gas gathering lines as large as 36 inches in diameter with operating pressures up to 1480 psig.

The energy that can be released in a pipeline explosion or fire is proportional to a pipeline's throughput capacity. The potential impact radius formula in § 192.903, which calculates the radius of a circle within which the potential failure of a pipeline could have a significant impact on people or property, increases proportionally with pressure and exponentially with the diameter of the pipeline. An incident on any large-diameter, high-pressure natural gas pipeline can have potentially catastrophic consequences, regardless of whether it is defined as a transmission or gathering line, and even in sparsely populated Class 1 locations. For example, one of the deadliest gas transmission pipeline incidents in U.S. history occurred in a Class 1 location when a 30-inch transmission line operated at 675 psig ruptured near Carlsbad, New Mexico, on August 19, 2000.[48] In that incident, internal

[36] EIA, ''Gulf of Mexico—Offshore Natural Gas Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/na1060_r3fmtf_2a.htm* (accessed Nov. 9, 2020); EIA, ''Pennsylvania Natural Gas Gross Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/n9010pa2a.htm* (accessed Nov. 9, 2020).

[37] EIA, ''Annual Energy Outlook 2021'' (Feb. 3, 2021), *https://www.eia.gov/outlooks/aeo/production/sub-topic-01.php.*

[38] DOE, ''Appendix B: Natural Gas—Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,'' at NG–11 (Apr. 2015), *https://www.energy.gov/sites/prod/files/2015/04/f22/QER-ALL%20FINAL_0.pdf.*

[39] EIA, ''Annual Energy Outlook 2004 With Projections to 2025,'' at 133 (Jan. 2004), *https://www.eia.gov/outlooks/archive/aeo04/pdf/0383(2004).pdf.*

[40] *Id.* at 90.

[41] Henry Hub is a Louisiana natural gas distribution hub where conventional Gulf of Mexico natural gas can be directed to gas transmission lines running to different parts of the country. Natural gas bought and sold at the Henry Hub serves as the National benchmark for U.S. natural gas prices. *Id.* at NG–29, NG–30.

[42] EIA, ''Natural Gas Spot and Futures Prices,'' *http://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm,* (accessed Nov. 9, 2020).

[43] *Id.*

[44] EIA, ''Electric Power Annual 2019'' Table 3.1.A (Oct. 2020), *https://www.eia.gov/electricity/annual/* (accessed Nov. 9, 2020).

[45] EIA, ''U.S. Natural Gas Exports,'' *https://www.eia.gov/dnav/ng/hist/n9130us2a.htm* (accessed November 9, 2020).

[46] NAPSR, Resolution 2010–2AC–2 (Sept. 30, 2010), *http://nebula.wsimg.com/215b293abe58ff21d6d2ad867ae864a3?AccessKeyId=8C483A6DA79FB79FC7FA&disposition=0&alloworigin=1.*

[47] GAO, No. 14–667 at 24.

[48] National Transportation Safety Board (NTSB), NTSB/PAR–03/01, ''Pipeline Incident Report: Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico'' (Feb. 2003), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR0301.pdf.*

corrosion led to an explosion that killed 12 individuals who had been camping 675 feet from the rupture site. Following this incident, PHMSA added § 192.476 requiring operators to incorporate measures to mitigate internal corrosion threats in the design and construction of new transmission lines—however, that requirement does not affect gathering lines that may have a similar risk profile. In another incident on December 11, 2012, a 20-inch transmission line with a MAOP of 1000 psig ruptured in Sissonville, West Virginia, due to corrosion caused when the protective pipe coating was damaged by rocky backfill during installation. While there were no serious injuries in that incident, three houses and several hundred feet of road surface were destroyed, and Interstate 77 was shut down for 19 hours.[49] The fire melted a portion of the interstate highway, prompting one local official to describe the highway as looking ''like lava, just boiling.'' [50]

Although PHMSA has not historically collected incident reports for gas gathering lines in Class 1 locations, such gathering lines are subject to incidents of similar magnitude and consequence as gas transmission pipelines with comparable physical and operating characteristics. For example, on November 14, 2008, a 20-inch gas gathering line exploded in Grady County, Oklahoma, which injured two people, destroyed three homes, and shut down a nearby highway.[51] On June 8, 2010, a bulldozer struck a 14-inch gas gathering line in Darrouzett, Texas, causing an explosion that killed two workers and injured three others, including one worker who was critically injured and required medical evacuation by helicopter.[52] On June 29, 2010, three men working on a 24-inch gas gathering line in Grady County, Oklahoma, were injured when it exploded; one worker was airlifted to a nearby hospital with burns covering half of his body.[53] On August 1, 2018, a six-inch gas gathering line failed in Midland, Texas, which caused a nearby 12-inch transmission line to also explode, killing one worker and injuring seven others.[54] A few days later, on August 9, 2018, corrosion on a 10-inch gas gathering line resulted in another explosion in Midland, killing a three-year-old girl and badly burning three others. Fatal incidents on smaller lines such as the first Midland, Texas, incident described above and an explosion caused by an improperly abandoned 2-inch production line connected to a gas well in Firestone, Colorado,[55] underscore the need to collect information on the risks posed by smaller diameter lines. Even non-fatal incidents can result in significant damage to infrastructure and property, lead to evacuations, disrupt gas service, or otherwise harm the public, property, or the environment.

These hazards may be further exacerbated by the changing geography of U.S. gas production, which was noted by the GAO in their March 2012 report, ''Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety.'' Incidents involving new gas production fields may overwhelm the capabilities of local first responders in rural areas who may lack experience and the resources to respond adequately to serious incidents associated with intensive gas production and processing operations, including high-pressure pipelines.

Regulatory Gaps

PHMSA estimates that there are over 400,000 miles of unregulated onshore gathering lines. For comparison, operators reported 320,000 miles of gas transmission lines in 2019. As demonstrated above, even though some gathering lines share the same physical, functional, and operational characteristics and potential adverse consequences from an incident as transmission lines, they are exempt from reporting requirements in part 191 and minimum safety standards in part 192.

The final rule closes this gap by requiring all gas gathering facilities to submit incident reports and annual reports under part 191. In addition, the final rule adopts minimum safety standards for larger gas gathering lines that operate at higher pressures to help to ensure that operators address the critical risks that these previously unregulated facilities pose to pipeline integrity and public safety such as corrosion, excavation damage, and inadequate emergency response planning.

B. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM, soliciting public comments regarding the revision of the Pipeline Safety Regulations applicable to the safety of both gas gathering and gas transmission pipelines.[56] PHMSA requested comments regarding 15 topic areas covering gathering and transmission lines.

The specific issues related to gas gathering included whether regulatory exemptions for filing incident, annual, and safety-related condition reports should be repealed. In addition, PHMSA requested comment on a proposal to repeal the incorporation by reference of API RP 80 into the Pipeline Safety Regulations and replace it with a new definition of gathering lines in part 192 for determining the beginning and end points of gas gathering lines. Adoption of a new definition would address defining endpoints for non-jurisdictional gas production operations and setting limits for the ''incidental gathering'' concept in API RP 80. PHMSA also requested comment on expanding the definition of the term ''regulated onshore gas gathering pipelines'' to include a new category of high-pressure, large diameter gathering lines in Class 1 Locations.

PHMSA received 103 comments to the ANPRM. Based on these comments, PHMSA developed proposals for some of those topics in an NPRM published on April 8, 2016 (NPRM), which is the basis for this final rule.

C. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

Section 21 of the 2011 Pipeline Safety Act mandated that DOT review its existing regulations for gas gathering lines and report to Congress on the sufficiency of existing Federal and State laws to ensure the safety of gas

[49] NTSB, NTSB/PAR–14/01, ''Accident Report: Columbia Gas Transmission Corporation Pipeline Rupture Sissonville, West Virginia'' (Feb. 2014), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1401.pdf.*

[50] Brinks, Travis, ''Remembering the Sissonville Pipeline Explosion.'' *WV Metro News.* Dec. 11, 2023, *https://wvmetronews.com/2013/12/11/remembering-the-sissonville-pipeline-explosion/* (accessed June 15, 2021).

[51] Griswold, Jennifer and Sargent, Brian. ''Natural Gas Pipeline Explosion Destroys Homes Near Alex.'' *The Oklahoman,* Nov. 14, 2008, *www.oklahoman.com/article/3321932/natural-gas-pipeline-explosion-destroys-homes-near-alex* (accessed Feb. 12, 2021).

[52] The Associated Press. ''Two Killed in Texas Panhandle Gas Line Explosion.'' *Arkansas Democrat Gazette,* June 8, 2010, *www.arkansasonline.com/news/2010/jun/08/2-killed-texas-panhandle-gas-line-explosion/* (accessed Feb. 12, 2021).

[53] Pittman, Jerry. ''Pipeline Explosion West of Pocasset Injures Three, One Seriously.'' *The Oklahoman,* June 29, 2010, *www.oklahoman.com/article/3472182/pipeline-explosion-west-of-pocasset-injures-three-one-seriously,* (accessed Feb. 12, 2021).

[54] Lee, Mike, and Soraghan, Mike. ''Deadly Pipelines, No Rules.'' *E&E News,* Mar. 4, 2019, *www.eenews.net/special_reports/EEnews_highlights/stories/1060123021,* (accessed Feb. 12, 2021).

[55] NTSB, NTSB/PAB–19/02, ''Pipeline Accident Brief Natural Gas Explosion at Family Residence Firestone, Colorado'' (Oct. 2019), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAB1902.pdf.*

[56] Pipeline Safety: Safety of Gas Transmission Pipelines, 76 FR 53086.

gathering lines; the economic impacts, the technical practicability, and challenges of applying existing Federal regulations to unregulated gathering lines; and the need to modify or revoke existing exemptions from Federal regulation for gathering lines, subject to a risk-based assessment. PHMSA sent the required report to Congress on May 8, 2015.[57] The report identified issues with the difficulty of designated gathering lines in complex systems due to missing, ambiguous, or circular definitions of terms used to determine the start and end points of gathering lines, and used to describe state-level regulation of gathering lines. The report also observed that, with few exceptions, State regulators had not imposed design, construction, operation, and maintenance requirements for gathering lines beyond existing Federal requirements for Type A and Type B regulated gathering lines. The report also notes that most of the States which had established requirements for gathering lines other than Federally regulated Type A and Type B gathering lines had not adopted prescriptive safety standards or performance standards with well-defined authorized acceptance criteria. The report informs this rulemaking.

D. Government Accountability Office (GAO) Recommendations

The GAO issued GAO–12–388 in March 2012, which recommended PHMSA collect data on Federally unregulated hazardous liquid and gas gathering lines comparable to the data collected from operators of regulated gathering lines. The GAO suggested that the purpose of such data collection would be to assess the safety risks posed by unregulated gathering lines. GAO also noted that States and operators could use this information to share effective safety practices and lessons learned. In August 2014, the GAO issued a report, GAO–14–667, which further recommended that PHMSA initiate a rulemaking to address gathering line safety that would focus on the risks presented by larger-diameter, higher-pressure gathering lines, including a requirement that such pipelines meet emergency planning requirements.[58]

E. Notice of Proposed Rulemaking

On April 8, 2016, PHMSA published the NPRM, which proposed new pipeline safety requirements and revisions of existing requirements in 16 major topic areas.

To manage the breadth of the topics raised in the NPRM, PHMSA separated the topics into three final rules. The first of final rule addressed the gas transmission mandates in the 2011 Pipeline Safety Act; a final rule was published in this rulemaking on October 1, 2019.[59] That final rule addresses comments received concerning the scope of the proposed gas transmission requirements for existing Type A and Type B regulated gathering lines. The second final rule is this one, which addresses only the portions of the NPRM affecting the safety of gas gathering lines, particularly reporting requirements for all gas gathering lines and additional requirements for Type C regulated gathering lines. The remaining gas transmission pipeline concerns are being considered in a third final rule (under Regulatory Identification Number 2137–AF39) that is under development.

With respect to the current rulemaking, the NPRM contained proposals to:

(1) Extend part 191 requirements for incident reports, annual reports, and safety-related condition reports to all gas gathering lines;

(2) repeal the incorporation by reference of API RP 80 and revise the regulatory definitions for determining if a pipeline is a gathering line;

(3) expand the scope of regulated gathering lines to include a new category of ''Type A, Area 2'' for gathering lines in Class 1 locations with a diameter of 8 inches or greater and operating at high pressure; and

(4) require newly regulated Type A, Area 2 gathering lines to comply with the existing requirements in § 192.9 for Type B gathering lines, plus an additional requirement for establishing emergency plans per § 192.615.

Pursuant to 49 U.S.C. 60115(c), PHMSA shared the proposed standards on gathering lines with the Gas Pipeline Advisory Committee (GPAC) after initially considering the comments to the NPRM.[60] The GPAC met on June 25–26, 2019, to consider the proposed standards regarding gathering lines. Subsequently, PHMSA posted the meeting slides that were used for the GPAC votes as well as the transcript, which constitute the statutorily required report of the GPAC's recommendations, including minority views.[61]

A summary of the four pertinent NPRM proposals, comments received on these proposals, the GPAC recommendations, and PHMSA's responses to the comments are provided in section III below.

F. Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020

The 2020 PIPES Act was enacted on December 28, 2020. Section 112(a) directed PHMSA to issue a final rule in this rulemaking by the March 27, 2021.

III. Summary of the NPRM Comments, and GPAC Recommendations, and PHMSA Responses

The comment period for the NPRM ended on July 7, 2016, after being extended for one month. PHMSA received over 400 comments from groups representing the regulated pipeline industry; groups representing public interests, including environmental organizations; State utility commissions and regulators; members of Congress; individual pipeline operators; and private citizens. PHMSA received several comments after the July 7, 2016 deadline. Consistent with §§ 5.13(i)(5) and 190.323, PHMSA considered those late-filed comments considering commenters' interest in the rulemaking and the absence of additional expense or delay resulting from their consideration.

Pursuant to 49 U.S.C. 60115(e), the GPAC met on June 25 and 26, 2019 to consider the topics related to the safety of gas gathering lines in the NPRM. The GPAC came to consensus decisions and voted on recommended changes to the NPRM elements that would make those regulatory amendments more technically feasible, reasonable, cost-effective, and practicable. These recommendations are documented in

[57] PHMSA, Report to Congress: Natural Gas and Hazardous Liquid Gathering Lines (May 2015), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/report_to_congress_on_gathering_lines_0.pdf.*

[58] On September 29, 2015, GAO prepared a statement, GAO–15–843T (''Department of Transportation Needs to Complete Regulatory, Data, and Guidance Efforts'') reiterating the need for PHMSA to complete its regulatory efforts based on GAO's previous recommendations.

[59] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 FR 52180.

[60] The Technical Pipeline Safety Standards Committee, or GPAC, is an advisory committee, created pursuant to 49 U.S.C. 60115, that advises PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas pipelines. The GPAC was established under the Federal Advisory Committee Act (Pub. L. 92–463) and section 60115 of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*). The GPAC consists of 15 members, with membership divided among Federal and State agencies, the regulated industry, and the public. The GPAC considers the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

[61] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143.*

the transcript of the meeting and summarized in the vote slides.[62]

A. Reporting Requirements—§§ 191.1, 191.15, 191.17, 191.23, and 191.29

1. Summary of PHMSA's Proposal

Existing § 191.1(b)(4)(ii) exempts all onshore gas gathering lines other than regulated gathering lines (as specified in accordance with § 192.8) from all reporting requirements of part 191.

The NPRM proposed to repeal the exemption in § 191.1(b)(4) for gas gathering lines that are not regulated under § 192.8. However, the NPRM would continue to exempt previously unregulated gathering lines from Operator Identification Number (OPID) validation requirements in § 191.22(b) and National Pipeline Mapping System (NPMS) requirements in § 191.29. Therefore, all gas gathering lines, including previously unregulated gathering lines, would be required to comply with annual and incident reporting requirements in §§ 191.15, 191.17, and 191.25. This proposal was intended to provide new information on the extent, configuration, and safety performance of previously unregulated gas gathering lines.

The proposed rule would have required submission of OPID requests, incident reports, and safety-related condition requests beginning on the effective date of a final rule. Annual reports would have been due on March 15 of the calendar year after the effective date of a final rule.

2. Summary of Public Comments

Several citizen and public safety, and environmental groups, including the Pipeline Safety Trust (PST), the Wisconsin Safe Energy Alliance, NAPSR, the Coalition to Reroute Nexus, Earthworks, and the Environmental Defense Fund (EDF), supported the proposed provisions to remove the exemption for filing reports by operators of unregulated gas gathering lines. NAPSR agreed that extending reporting requirements to ''unregulated'' gathering lines would help determine if current operation and maintenance practices pose a risk to public safety and if additional requirements are required but suggested that PHMSA consider limiting certain requirements that could pose an unnecessary burden, such as detailed leak reporting information in part M of the gas transmission and gas gathering annual report form (DOT Form PHMSA F 7100.2–1). Some public commenters emphasized that available data on unregulated facilities could be inaccurate or outdated, particularly in areas where gas development has grown rapidly. Some of these groups also encouraged PHMSA to require gas gathering operators to submit geospatial pipeline location data for the NPMS, citing the usefulness of NPMS data for determining the need for future regulation.

Trade associations and pipeline industry entities provided a variety of responses to the proposed reporting requirements, ranging from full support, including for NPMS reporting, to total opposition to all proposed reporting requirements. The Independent Petroleum Association of America (IPAA) and other commenters representing oil and gas producers opposed changes to the scope of part 191 and commented that PHMSA has no statutory authority to apply reporting requirements to production lines and gathering lines that are not regulated gathering lines determined pursuant to § 192.8.

Several trade association and pipeline industry commenters including API, GPA Midstream (formerly the Gas Processors Association) and IPAA, expressed concern that the proposed reporting requirements could have significant cost impacts for operators that were not commensurate with the risk posed by the majority of those lines. Industry commenters also commented that it is not feasible to collect the information necessary to complete the proposed annual report by the reporting deadline of March 15 as required by § 191.17 on top of the efforts necessary to identify Type A, Area 2 (or Type C) regulated gas gathering lines within six months of the effective date the rule (see section III.C. below).

Industry commenters were especially concerned about reporting requirements for pipeline attributes that were related to requirements that did not apply to unregulated gas gathering lines. For example, GPA, API, and other industry commenters argued that the reporting of safety-related conditions (§ 191.23), including MAOP exceedances, would require information on MAOP, corrosion monitoring, and SMYS that were not otherwise required for previously unregulated gathering lines. The current forms for submitting gas transmission and gathering incident reports (F 7100.2) and annual reports (F 7100.2–1) also refer to regulations or records not required for unregulated gas gathering operators. These commenters recommended that PHMSA create separate incident and annual report forms for gathering lines that would collect information relevant to gas gathering lines that are not subject to part 192 and eliminate the proposed requirement to report safety-related conditions.

GPA Midstream commented that they supported PHMSA's goal of collecting necessary information on gas gathering lines, but that an abbreviated annual report form was necessary to avoid unnecessary costs. GPA Midstream further commented that unregulated gas gathering lines should be excepted from the OPID validation and change notification requirements in § 191.22(b) and (c).

3. GPAC Recommendations

Following discussion in the June 2019 meetings, the GPAC voted 12–0 that the proposed requirement that operators of newly regulated gas gathering lines file annual and incident reports pursuant to part 191 was technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Add specificity to location (*e.g.,* latitude and longitude coordinates) and cause information to the incident report form;
- Make sure all appropriate current annual report data elements are incorporated in the annual report form for currently unregulated gathering lines, including decade of installation;
- Address the possibility of unknown data;
- Implement a phase-in period of at least 24 months for unregulated gathering annual reports; and
- Consider additional comments from members submitted to the meeting docket (PHMSA–2016–0136), specifically, position papers from API/GPA Midstream and PST submitted in response to the GPAC meeting notice, and comments submitted after the GPAC meeting by each of GPA Midstream and the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada, AFL–CIO.

The GPAC agreed that the proposed reporting requirements were needed to support future oversight, but recommended changes on the details of implementation. PHMSA explained that it intended to create a new annual report form for gas gathering lines that are not subject to safety requirements in part 192 (reporting regulated gathering lines) separate from the existing DOT Form PHMSA 7100.2–1 required for operators of gas transmission and regulated gas gathering lines. This form would exclude information that is not relevant or applicable to operators of pipeline systems that are not required to comply with part 192.

[62] *See https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143.*

The GPAC recommended extending the compliance deadline for annual reports to 24 months after publication in the **Federal Register** to grant additional time for operators to identify newly regulated gathering lines and collect the necessary information. However, the GPAC agreed that incident reports should begin to be filed on the effective date of the rule since the data required to submit an incident report should be readily obtainable when an incident occurs.

4. PHMSA Response

PHMSA disagrees with comments that it lacks the statutory authority to require reports from operators of gathering lines other than currently regulated gathering lines as determined under § 192.8. Section 60117(b) of Federal Pipeline Safety Law specifically authorizes the Secretary to ''require owners and operators of gathering lines to provide the Secretary information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines.'' Congress made no distinction between ''gathering lines'' and ''regulated gathering lines'' for reporting purposes. This information-gathering process is precisely what the NPRM proposed—to gather information on all gathering lines that would enable PHMSA to make informed judgments about the need for, and scope, of potential regulation. Congress intended that the Secretary have the authority to request information from operators of unregulated gathering lines in order to help determine ''what additional gathering lines should be regulated.'' [63] PHMSA seeks to obtain information regarding current risks to people, property, and the environment due to unregulated rural gathering lines to determine whether rural gathering lines are presenting unacceptable risk that would warrant additional regulations. The information contained in annual and incident reports submitted by operators under part 191 would reasonably help achieve this objective.

In addition to the plain meaning of section 60117, Congress has articulated its intent for DOT to obtain information about the risks of rural gathering lines. In 1992, when Congress granted DOT authority to define gathering lines and regulated gathering lines for purposes of safety regulations, it recognized that some rural gathering lines might present unacceptable risks and authorized DOT to regulate lines whose risk warranted regulation. In its report on H.R. 1489, a bill leading to the Pipeline Safety Act of 1992, the House Committee on Energy and Commerce instructed DOT to ''find out whether any gathering lines present a risk to people or the environment, and if so, how large a risk and what measures should be taken to mitigate the risk.'' [64] The Committee reasoned that ''DOT had been attempting to define gathering lines for years. Anecdotal evidence indicates that there may be pipelines that are called gathering lines but that may really be transmission lines, and that there may be gathering lines that because of size or other physical characteristics should be regulated.'' [65] Although Congress did not require DOT to regulate gathering lines, it expected DOT to obtain the necessary information to determine whether risks exist to warrant regulation, as further evidenced by the House report: ''DOT is given a great deal of discretion to implement this section based on the information it receives as it proceeds. If DOT finds that none of these lines poses a hazard to people, property, or the environment, none of them will be regulated.'' [66]

The final rule fulfills the Congressional mandate by requiring operators of all onshore gas gathering lines to file incident and annual reports under part 191. This includes pipelines that are not currently designated as Type A or Type B regulated gathering lines nor newly designated as Type C gathering lines as a result of the final rule. For clarity, this final rule designates these reporting-regulated lines as ''Type R'' gathering lines that are subject to reporting under part 191 but are not designated as regulated gathering lines in part 192. These requirements are necessary to evaluate the safety risks on gas gathering systems and determine what, if any, additional measures may be warranted to reduce those risks. As demonstrated above, it is no longer reasonable to assume rural gas gathering lines pose uniformly low risk. Information on the changing functional and operational characteristics of gas gathering lines and their safety performance is necessary for PHMSA to better understand the consequences of these changes and to set requirements for gathering lines in the future. Extension of incident and annual reporting to these additional gas gathering lines will provide PHMSA information needed for identifying—and promulgating regulatory requirements or pursuing enforcement activity—design, manufacture, installation, and operational/maintenance issues common to particular pipeline characteristics or operators.

Congress also understood that the community around gathering lines can change and authorized DOT to consider these changes when regulating gathering lines. In its report that accompanied Senate Bill 1166, the bill that became the Natural Gas Pipeline Safety Act of 1968, the Committee on Interstate and Foreign Commerce recognized that the population in an area can change, and that the statute authorized DOT to define from time to time what is a non-rural area.[67] The Committee emphasized that a ''populated area'' means not only an area with a large number of people but also areas where pipeline rights-of-way are near houses, schools, and places of employment.[68]

However, PHMSA recognizes that some reporting requirements applicable to gas transmission and regulated gathering lines may not be necessary for gas gathering lines that are not currently subject to part 192. In particular, PHMSA is not requiring operators who are not required to establish an MAOP under part 192 to comply with requirements to report MAOP exceedances and other safety-related condition reports. In addition, in consideration of the comments, PHMSA is withdrawing the proposed requirement for gas gathering line operators that are not subject to part 192 to file safety-related condition reports required by § 191.23. Similarly, the final rule exempts gas gathering lines that are not subject to part 192 from the OPID validation and construction notification requirements in § 191.22(b) and (c) because such pipelines are not subject to the construction requirements in part 192.

While all gathering lines are now required to submit incident and annual reports, PHMSA is ensuring that the required data is applicable and relevant to operators of Type R gathering lines that are not subject to part 192. In consideration of comments on the NPRM and in the GPAC recommendations, PHMSA has

[63] S. Rep. 104–334, section 12 (104th Cong., 2nd Sess. 1996).

[64] H.R. Report No. 102–247(1), at 2653 (102nd Cong., 1st Sess. (1991)).

[65] *Id.*

[66] *Id.* Additionally, 49 U.S.C. 60101(b)(2)(A) specifically requires the Secretary, when defining ''regulated gathering line,'' to consider factors as location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas to determine which lines are functionally gathering and should be regulated because of their physical characteristics. It reasonably follows, as evident in the Congressional record, that Congress intended that Secretary could obtain such information from operators in order to consider such factors.

[67] H.R. Rep. 90–1390, at 3234 (90th Cong., 2nd Sess. 1968).

[68] *See id.*

developed a new annual report form and a new incident report form for operators of gas gathering lines that are not subject to part 192 with more limited information that is appropriate for such facilities. For example, with regard to annual reports, PHMSA has developed an abbreviated annual report form incorporating information specifically relevant to gas gathering lines that are not currently regulated under part 192, including the decade of installation, if known. New forms and instructions are available in the public docket and will be made available on PHMSA's website at *https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions.*

The new annual report and incident report forms for Type R gathering lines address the GPAC's recommendations, including:

- Requiring incident location information that is equivalent to what is required for regulated gas gathering lines;
- Annual report fields appropriate for identifying and evaluating public safety and environmental risks that may be associated with unregulated gas gathering lines, including:
  - Miles by decade of installation,
  - Miles by pipeline diameter,
  - Miles by pipe material and corrosion protection status, and
  - Number of leaks repaired or scheduled for repair.
- On the Type R annual report form, allow reporting of an unknown decade of installation.
- On the Type R incident report form, allow reporting of an unknown date of installation and certain fields related to pipeline material properties and damage prevention investigations.

In the final rule, operators of previously unregulated gas gathering lines must begin submitting annual reports beginning with the first annual report cycle occurring after the endpoints of Type C or Type R gathering lines have been determined one year after the publication date of the final rule. As a result, operators of Type R and Type C gathering lines must submit a 2022 annual report no later than March 15, 2023. March 15 is the existing deadline for submitting annual reports for other gas pipeline facilities, consistent reporting deadlines reduces confusion and administrative burdens on PHMSA and operators with both Type R and regulated gas pipeline facilities. This compliance deadline represents a phase-in period well in excess of a year as measured from the publication date of the final rule.

This compliance deadline is approximately 6 months shorter than recommended by the GPAC. However, PHMSA believes that prompt submission of such reports is necessary for PHMSA's timely evaluation of whether additional regulatory efforts are needed to manage the safety and environmental risks associated with Types C and R gathering lines. PHMSA's limited information on these lines inhibits the robust understanding of their environmental and public safety risks needed to determine whether additional requirements are also warranted. The longer the delay in obtaining that information, the longer before PHMSA can diagnose and respond to a need for additional public safety and environmental protections from previously-unregulated gas gathering lines. PHMSA therefore does not believe an [18 month] compliance timeline would be overly burdensome on affected operators when evaluated against those potential safety benefits. The simplified form for Type R lines includes provisions for ''unknown'' fields to minimize burdens on gathering line operators to complete. While the Type C form is more extensive, such lines are also more likely to be more modern shale gas systems installed within the last 10–15 years. PHMSA expects the use of electronic recordkeeping and geospatial information systems is more widespread among such operators compared with traditional gathering systems and therefore expects that completing Type C annual reports will not be overly burdensome on affected entities. Finally, PHMSA notes that the compliance timeline is consistent with the approach taken in historical expansions of pipeline reporting requirements. For example, in the final rule titled, ''Pipeline Safety: Safety of Hazardous Liquid Pipelines,'' [69] PHMSA required affected operators to submit annual reports the first year after the effective date.

For similar reasons, the final rule does not include provisions for operators to request a delayed compliance deadline for the annual report requirement similar to those included in §§ 192.8 and 192.9. Additionally, most of the records necessary to prepare an annual report are also necessary in order to define the endpoints of regulated gas gathering. Operators should therefore begin collecting the necessary information immediately in order to ensure they are able to submit a complete annual report on or before the deadline in the final rule.

[69] 84 FR 52260 (Oct. 1, 2019).

B. Gathering Line Definitions—§§ 192.3 and 192.8

1. Summary of PHMSA's Proposal

PHMSA proposed to revise 49 CFR part 192 to clarify the definition of gathering lines in order to address confusion regarding how the endpoints of gathering and production are currently determined. The existing definition of gathering lines relies on language in API RP 80. In practice, however, operators and inspectors have had difficulty consistently applying the definitions that are used to define the start and endpoints of gathering in API RP 80 given the complexities in the configuration of gathering line systems in midstream operations. In addition, Federal and State enforcement of the current requirements has been hampered by the use of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system. Specifically, API RP 80 defines certain processes and equipment that may constitute a ''production operation'' but does not include defined endpoints of the production function in section 2.3 like it does for gathering in section 2.2.

This issue was raised in comments by NAPSR and others, who suggested simplifying the definition of a gas gathering line and setting clear, restrictive limits on where non-jurisdictional production operation ends and gas gathering begins. NAPSR commented in response to the ANPRM that State regulators had ''many difficulties in applying the definitions contained in API RP 80'' and recommended a simpler definition for the term gathering line. NAPSR recommended defining the end of production at the wellhead or first metering point downstream of the well. As described in the regulatory history section, PHMSA also had concerns with how the ''incidental gathering'' concept has been used to classify pipelines that perform gas transmission functions as gathering lines subject to less stringent requirements intended for small, low-pressure, traditional gathering lines.

In lieu of relying on API RP 80's definition of gathering line, the NPRM proposed new stand-alone definitions for ''onshore production facility/operation'', ''gas processing plant,'' ''gas treatment facility'', and ''gathering line (onshore)'' to determine the beginning and endpoints of each gathering line. The proposed definitions were found in § 192.3 of the NPRM and the application of those definitions was included in § 192.8. PHMSA proposed to define the end of onshore production operations as the furthermost downstream point

where measurement for the purposes of calculating minerals severance occurs or there is a comingling of the flow stream from two or more wells.

The NPRM also would have required operators to request approval from the Associate Administrator of Pipeline Safety in order to extend gathering beyond the furthermost upstream gas processing plant. Finally, in order to address PHMSA's concerns with the lack of definite limits on the application of incidental gathering, PHMSA proposed limiting the distance that a gathering line could continue beyond a defined endpoint of gathering to 1 mile, provided that it does not cross a highway or railroad right of way.

2. Summary of Public Comments

NAPSR, the Pennsylvania Public Utility Commission (PAPUC), PST, EDF, and a member of the public all expressed support for elimination of API RP 80, citing the confusion that exists in the present document for defining the endpoints of gas production and processing facilities and gas gathering lines. Some of these commenters had concerns or suggested clarifications about specific issues. For example, NAPSR and other State pipeline safety officials suggested PHMSA clarify that authority to approve extending gathering beyond the first downstream natural gas processing plant (§ 192.8(a)(2)) or to use the point of comingling on fields greater than 50 miles apart (§ 192.8(a)(3)) resides with State pipeline safety agencies in addition to the PHMSA Associate Administrator for Pipeline Safety. The PAPUC commented that PHMSA should remove the point of gas comingling (the location where gas from two or more production sites join for further transportation downstream) from the proposed definition of an onshore production operation due to concerns that operators could use that concept to classify relatively large pipelines that are performing a gathering function as non-jurisdictional production lines.

API, The American Gas Association (AGA), IPAA, GPA Midstream, the Marcellus Shale Coalition, the Oklahoma Oil and Gas Association (OKOGA), the Domestic Energy Producers Alliance, and several individual pipeline operators commented that API RP 80 adequately delineated production and gathering lines on a functional basis and should not be eliminated from part 192. Most signaled that they would be open to collaboration to improve some definitional issues, especially via changes to API RP 80 through the collaborative API standards-revision process. To this end, API suggested initiating a revision of API RP 80 instead of using the proposed wording in the NPRM. Other industry groups and operators, such as the Virginia Oil and Gas Association and the Plastic Pipe Institute, opposed any modification to the current definitions and usage of API RP 80; these commenters contended that changing the start point of gathering would violate PHMSA's statutory limitation on regulating production lines, that State agencies adequately regulate intrastate production and gathering lines, or that PHMSA had not provided sufficient safety evidence to support changes to the definition of gathering.

Industry commenters also raised a number of specific concerns regarding the replacement definitions proposed by PHMSA. The most substantive comments concerned potentially ambiguous language in PHMSA's proposed definitions for ''onshore production facility or onshore production operation'' and ''gathering line (onshore).'' API opposed the proposed definitions but suggested edits that it claimed would provide more specificity to the types of processes that could be considered production functions. API also suggested clarifications on how points of comingling are treated in the definitions of the endpoints of gathering and production and make other changes. Other commenters requested clarification that the proposed definitions of gas processing plants and gas treatment plants did not apply to facilities on gas transmission or distribution lines. Many industry commenters requested a standalone definition of ''farm taps'' to clarify the regulatory requirements applicable to service lines connected to production, gathering, and transmission lines.

Many commenters opposed PHMSA's proposal to limit the use of the ''incidental gathering'' designation to one mile from the furthermost downstream point of gathering. API proposed a standalone definition of ''incidental gathering'' consistent with the current definition in API RP 80 and suggested that if PHMSA is concerned about particular lines abusing the definition of incidental gathering, then it should designate such incidental gathering lines as regulated gathering lines rather than generally restrict the use of the incidental gathering designation in API RP 80. It further suggested that the proposed Type A, Area 2 (now Type C) requirements could address safety concerns with large-diameter, high-pressure incidental gathering lines. API further commented that requiring operators to redesignate previously unregulated incidental gathering lines as transmission lines would result in significant costs, especially if the proposed gas transmission requirements in the NPRM applied to them. GPA Midstream commented that the ''proposed limitation of one mile is too restrictive,'' and that reclassifying existing gathering lines as transmission lines would result in substantial compliance costs that need to be addressed in the RIA. However, GPA Midstream and the OKOGA suggested that a 10-mile limit was a reasonable compromise that would establishes a definite limit on incidental gathering but with enough flexibility to accommodate different system configurations.

Industry commenters also contended that the implementation timeframe for identifying and reclassifying pipelines as regulated gathering lines (6 months) was too short.

3. GPAC Recommendation

The GPAC voted 11–0, with one abstention, that the proposed rule was technically feasible, reasonable, cost-effective, and practicable, if the proposed new and revised definitions related to gas gathering in § 192.3 and the proposed changes to § 192.8(a) for determining beginning and endpoints of gathering were withdrawn. PHMSA noted during the meeting that it will monitor the outcome of the working group preparing a second edition of API RP 80 and a new document, API RP 1182, ''Safety Provisions for Large Diameter Rural Gas Gathering Lines,'' and consider whether those efforts merit potential changes to the definition of gas gathering lines in a future rulemaking. Although the GPAC discussion acknowledged PHMSA's concerns regarding the ''incidental gathering'' concept in API RP 80, the GPAC did not discuss or recommend any particular mileage limitation on that concept. Likewise, the GPAC did not make any specific recommendations regarding the terms ''onshore production facility/operation'', ''gas processing plant'', ''gas treatment facility'', or ''gathering line (onshore)''.

4. PHMSA Response

PHMSA agrees with the majority of commenters and the GPAC that definitions of ''gas processing plant,'' ''gas treatment facility,'' and ''gathering line (onshore)'' should be omitted from the final rule. After the NPRM was published, API established two committees (API RP 1182 and API RP 80) to consider revisions to API RP 80 to address the same ambiguities in those

definitions that the NPRM was intended to address. Both documents have since published. The final rule does not repeal the use of the existing definition of gathering line based on API RP 80 (1st edition, 2000) and § 192.8. PHMSA will consider updating the definitions associated with defining gathering and production lines in a separate rulemaking after evaluating the second edition of API RP 80, *Definition of Onshore Gas Gathering Lines* and new API RP 1182, *Safety Provisions for Large Diameter Rural Gas Gathering Lines.* PHMSA declines to adopt in this rulemaking API RP 1182 or the 2nd edition of API RP 80 in their entirety without providing the public an opportunity to review and comment upon those standards. A few aspects of API RP 1182 have been adapted in the final rule, these are described in section III.C. of the preamble of this final rule.

However, due to safety and enforcement concerns, the final rule defines limits to ''incidental gathering'' on new, replaced, relocated, or otherwise changed gathering lines. The final rule changes the NPRM's proposed one-mile endpoint for the designation ''incidental gathering,'' but does impose a clear and defined limitation of ten miles on ''incidental gathering'' for any such pipelines constructed after the effective date of this rulemaking. Therefore, for gathering lines installed after the effective date of the rule, the ''connection to another pipeline'' endpoint in section 2.2(a)(1)(E) of API RP 80 may not be used if the connection is ten or more miles from the endpoints of gathering defined in paragraphs (a)(1)(A) through (a)(1)(D). In other words, if an ''incidental gathering'' portion of a newly constructed pipeline would be ten or more miles in length, then the incidental gathering concept may not be used and the gathering line terminates at the furthermost downstream endpoint defined in API RP 80 sections 2.2(a)(1)(A) through (a)(1)(d), subject to the limitations in § 192.8. While PHMSA appreciates the contribution of the API RP 80 committee on these definitional issues, ''incidental gathering'' concept is a significant source of uncertainty and concern that requires an immediate regulatory remedy to protect public safety. This limitation in the final rule immediately improves regulatory certainty regarding each of the endpoints of gathering and prevents potential abuse of the incidental gathering concept pending PHMSA's consideration of the second edition of API RP 80 and operational experience gained from implementation of the definitional changes in this final rule.

The purpose of API RP 80 was to define clear endpoints to the gathering and production lines based on their function and purpose and eliminate the circular definitions in part 192 at the time. While the definitions for the end of gathering in section 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 are not perfect, they provide some definite limits that are reasonably based on the function of the line in question. However, the incidental gathering concept negates both goals by allowing gathering to continue past what API itself defines as the end of gathering functions to the ''connection to another pipeline.'' This reintroduces the circular definitions in the original definition in § 192.3 that adoption of API RP 80 was intended to clarify. API RP 80 includes no limits to how far downstream the connection to another pipeline can be. As a result, PHMSA has observed supposedly incidental gathering lines that extend for several miles.

In addition to adding ambiguity to the regulations, unlimited application of incidental gathering creates a regulatory gap where long-distance pipelines that are functionally and operationally indistinguishable from transmission lines are classified as gathering lines with less stringent safety standards. By definition, an incidental gathering line is downstream of the last gathering function described in section 2.2 of API RP 80. Past that point the gas will not undergo further gathering-related processing or comingling. Incidental gathering can also include piping downstream of a major gas processing plant or a compressor used to increase downstream pressure so that the gas can be delivered to a transmission line (see section 2.2.1.2.4 of API RP 80); if that is the case, then the incidental gathering line is being operated at the same (high) pressure as the transmission line to which it is directly connected. In other words, such lines have functional and operational characteristics—including potential consequences—consistent with gas transmission lines, not production or gathering facilities. While some allowance to connect to nearby transmission facilities could be appropriate on economic or practicability grounds, this justification fades the further downstream it is applied.

In order to reduce this regulatory gap for gathering lines that are downstream of the last gathering function, the final rule limits incidental gathering to no more than 10 miles from the furthermost downstream endpoint of gathering for new, replaced, relocated, or otherwise changed pipelines. Specifically, PHMSA no longer allows the use of the ''connection to another pipeline'' endpoint in paragraph 2.2(a)(1)(E) of API RP 80 if it is 10 or more miles downstream of the furthermost of the other endpoints defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80. An ''incidental gathering'' pipeline installed after the effective date of the rule that extends beyond 10 miles shall be considered a transmission line, starting from the non-incidental endpoint of gathering defined in API RP 80. PHMSA currently uses a similar distance-based limit in § 192.8(a)(3) to set reasonable parameters for using the point of comingling, an actual gas gathering function, described in API RP 80 section 2.2(a)(1)(C) as an endpoint to gathering. While existing gathering lines are not affected by this change, such pipelines may be designated as Type C regulated gas gathering and subject to safety requirements, depending on their diameter, pressure, and operating environment (see sections III.C and III.D below).

Applying these limits on incidental gathering solely to only new, replaced, relocated, or otherwise changed gathering lines and revising the limit from 1 mile to 10 miles addresses the concerns raised by comments from operators while establishing a limit to incidental gathering going forward. Applicability to only new and replaced pipelines avoids disruption associated with reclassifying previously unregulated existing gathering lines as transmission lines and reduces the overall cost of the final rule for existing infrastructure. PHMSA recognizes that comments from operators broadly opposed the proposed 1-mile limit, and the GPAC did not recommend revisions to definition, including incidental gathering. However, as an alternative, a 10-mile limit was supported in public comments from GPA Midstream and OKOGA, trade associations for gas gathering line operators, and represents a reasonable first step towards establishing a firm endpoint to gathering. PHMSA also notes that a 10-mile limit on the ''incidental gathering'' concept would also be consistent with previous interpretation letters issued by PHMSA.[70] Extending the limit on incidental gathering to 10 miles provides greater flexibility for siting processing facilities and associated

[70] *See, e.g.,* PHMSA, Interpretation Letter No. PI–08–0010, Letter to State of Colorado Public Utilities Commission (Feb. 20, 2009) (endorsing use of ''incidental gathering'' concept for an 8-mile line), *https://cms7.phmsa.dot.gov/sites/phmsa.dot.gov/files/legacy/interpretations/Interpretation%20Files/Pipeline/2009/PI-09-0006.pdf.*

pipelines compared with the 1-mile limit in the proposed rule, addressing concerns raised in comments. PHMSA also notes that during this rulemaking process, there was support among both gathering line operators and public commenters to clarify the application of incidental gathering lines and impose common-sense limitations on the ''incidental gathering'' concept. Finally, as noted in the summary of comments, GPA Midstream and OKOGA submitted comments open to a 10-mile limit to incidental gathering rather than 1 mile as proposed in the NPRM.

Although the second edition of API RP 80 includes a 20-mile limitation to incidental gathering, PHMSA does not believe that newly constructed ''incidental gathering'' lines should be permitted to extend that far from a gathering facility. As explained in the NPRM, PHMSA has for more than a decade expressed concerns that the ''incidental gathering'' concept has been used to allow pipelines with certain characteristics (operating pressures, capacity, etc.)—and, consequently, risks to the public and the environment—resembling gas transmission lines to avoid part 192 regulatory requirements governing those lines. PHMSA does not, therefore, understand the 20-mile limit contemplated by API RP 80 to be as effective in capturing the safety and environmental benefits in comparison to what a more demanding mileage limitation would realize.

Further, PHMSA's discussion with various stakeholders revealed that there are very few incidental gathering lines that extend beyond 10 miles from the gathering facility; PHMSA is not aware of any, proposed new pipeline construction projects that would be classified as incidental gathering and extend 10 miles from the end of the gathering facility. The 10-mile limitation on incidental gathering, therefore, provides regulatory certainty to stakeholders, recognizes uncertainty regarding the cost impacts that could arise if incidental gathering is limited to 1 mile and on existing gas gathering lines, as proposed, and ensures that the regulatory gap that currently exists with regard to API RP 80's absence of a limitation on incidental gathering is closed for all newly constructed lines. PHMSA acknowledges that a regulatory gap remains for existing incidental gathering lines and new and replaced incidental gathering lines 10 miles or shorter. However, both new and existing incidental gathering lines with the highest potential safety hazards are either covered by existing safety standards for Type A and Type B regulated gas gathering lines in Class 2, Class 3, and Class 4 locations, or the new safety standards for Type C regulated gas gathering lines in Class 1 locations established by this final rule. These requirements are described in sections III.C and III.D. of the preamble to this final rule. PHMSA will reconsider the issue of definitions, including the endpoint of production and treatment of incidental gathering lines, in a separate rulemaking in order to ensure stakeholders are able to comprehensively comment on newly proposed definitions and the second edition of API RP 80. Infrastructure and incident data collected as a result of this rulemaking, inspection data, and the public comment process will help inform future limits to incidental gathering.

C. Expanded Scope of Gas Gathering Line Regulations—§ 192.8

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to create a new category of Type A regulated gas gathering lines in Class 1 locations that had a nominal diameter of 8 inches (actual outside diameter of 8.625 inches) or greater. This new category of regulated gathering lines was identified in the table of the proposed § 192.8 as ''Type A, Area 2'' (in the final rule it is referred to as Type C), lines. PHMSA proposed to define Type A, Area 2 regulated gathering lines as gathering lines located in Class 1 locations that meet the existing Type A features in the table in § 192.9(b) (*i.e.,* metallic with an MAOP that produces a hoop stress of 20 percent or more of SMYS, or non-metallic with an MAOP greater than 125 psig) that have a nominal pipe size of 8 inches or greater.

This change was intended to improve the safety of larger-diameter, higher-stress gathering lines that were previously exempt from Federal safety regulations at part 192. In the NPRM, these newly designated Type A, Area 2 (Type C) regulated gathering lines would have to comply with a basic set of requirements as set forth in § 192.9. The specific requirements for newly regulated gas gathering lines are discussed in section III.D of this document.

2. Summary of Public Comment

API, the Michigan Public Service Commission (Michigan PSC), the Texas Pipeline Association (TPA), and Atmos Energy Corporation (Atmos) recommended that more data should be collected before determining the appropriate scope of additional regulations. The PAPUC supported the extension of regulatory oversight to gathering lines in Class 1 locations, based on its experience with growing natural gas production in Pennsylvania, noting that gathering lines are being constructed with diameters equal to or larger than typical transmission lines and are being operated at much higher pressures than was typical in the past. NAPSR supported the proposed scope of the new gathering line requirements but also commented that its members believe all gathering lines should be required to comply with part 192, regardless of class location. Some environmental and safety groups also expressed support for the extension of regulations to gas gathering lines in Class 1 locations in order to reduce the risks of incidents, greenhouse gas emissions and other air pollution. For example, EDF supported requirements for the design, installation, construction, initial inspection and testing, corrosion control, damage prevention and leakage surveys in order to reduce methane emissions.

The North Dakota Petroleum Council, the Marcellus Shale Coalition, the AGA, the Plastics Pipe Institute (PPI), Spectra Energy Partners, API, GPA Midstream, the Northeast Gas Association, and some individuals submitted comments noting issues and uncertainty with the regulatory impact assessment. For example, GPA Midstream commented that the benefits analysis included information for offshore and Class 2 incidents that are not applicable to the proposed scope of this final rule and that the cost analysis underestimated the time and cost to identify newly regulated gathering lines in a short amount of time and comply with the new requirements, especially MAOP determination and public awareness. Many operators and industry groups expressed disagreement with applying regulations to all Class 1 gas gathering lines with outer diameters of 8.625 inches or greater, arguing that gathering lines on the smaller end of that category do not represent the large-diameter, high-pressure gathering lines referenced in the preamble of the NPRM and public discussions. API commented that if PHMSA does proceed with defining a new category of regulated gathering lines, gathering lines with outer diameter greater than 16 inches have the potential to pose a higher risk and should be the criteria for determining regulated gathering, rather than 8 inches. API further suggested that targeting lines with outer diameters greater than 16 inches would be more in the spirit of the risk-based philosophy of other parts of the code, such as integrity management. This suggestion was

repeated by GPA Midstream, the North Dakota, Petroleum Council, and others.

A number of commenters representing the pipeline industry expressed concerns with the deadlines to identify newly regulated gathering lines and then comply with the proposed regulations. For example, Rice Energy, Dominion East Ohio, API, and GPA Midstream commented that the implementation timeframe for identifying proposed Type A, Area 2 (now Type C) regulated gathering lines was too short. Industry commenters were especially concerned about the deadline to establish an MAOP, especially if the MAOP verification requirements proposed for gas transmission lines in the NPRM also applied to gathering lines. One commenter suggested an economic criterion to allow an exemption for operators of economically marginal, low stress gathering lines.

Some commenters expressed the view that the proposed Type A, Area 2 (now Type C) classification for newly regulated gas gathering lines could be confusing. Specifically, commenters found that designating newly regulated gas gathering lines as Type A, Area 2 (now Type C), and then requiring those pipelines to follow requirements similar to Type B rather than existing Type A requirements was cumbersome and risked conflating distinct regulatory requirements. A few commenters suggested a Type C designation rather than the proposed Type A, Area 2 (now Type C) designation. The GPAC recommended PHMSA address these concerns in the final rule.

3. GPAC Recommendation

GPAC voted 11–1 that the scope of newly regulated gas gathering lines in proposed § 192.8(b) and (c) is technically feasible, reasonable, cost-effective, and practicable if PHMSA considered the following:

- Establishing an initial framework for regulating Class 1 gathering lines that could be built upon in light of future information and experience;
- Setting a minimum set of requirements for gathering lines 8.625 inches in outside diameter and greater (considering, for example: Damage prevention; line markers; public awareness; leak surveys and repairs; design, installation, construction, and initial inspection and testing for new lines; and emergency plans). Give due consideration to the GPAC discussion on the costs and benefits of performing leakage surveys;
- Consider applying a PIR concept and additional requirements to provide safety and environmental protection for larger- diameter gathering lines (*e.g.,* greater than 12.75 inch outside diameter); and
- Ensuring that composite pipe [71] was adequately addressed to minimize the impact on its continued use. Note that this is discussed in section III.D below.

4. PHMSA Response

In response to public comments and the recommendations of the GPAC, PHMSA has changed the proposed ''Type A, Area 2'' designation for newly regulated gas gathering lines to ''Type C'' lines. PHMSA originally proposed use of the term ''Type A, Area 2'' (now Type C) because the newly regulated gas gathering lines have features similar to existing Type A pipelines in the table in § 192.8, except that they are located in Class 1 locations. However, PHMSA agrees that creating the category ''Type C'' may be less confusing. While adopting the new designation of Type C regulated gas gathering lines introduces some repetition in the table in § 192.8, PHMSA believes it will make clearer that the three categories represent different levels of risk that warrant corresponding levels of regulation and will reduce unnecessary confusion among operators and inspectors in the future.

The final rule continues to define Type C regulated gas gathering lines as gas gathering lines in Class 1 locations that are 8.625 inches or greater in diameter and are: (1) Metallic, with an MAOP producing a hoop stress of 20 percent or more of SMYS; (2) metallic, with an MAOP greater than 125 psig if the hoop stress is unknown; or (3) non-metallic, with an MAOP greater than 125 psig. However, PHMSA recognizes that not all gathering lines that meet these criteria pose the same level of risk. Therefore, the final rule provides that the requirements that Type C gathering lines must comply with will vary, based on the scale of risk associated with the particular characteristics of the pipeline. The applicability of each of the requirements that potentially applies to Type C lines is described in section III.D below and the section-by-section analysis. Gathering lines smaller than 8.625 inches in outside diameter or operating below the pressure or stress level criteria described above will remain unregulated under part 192 and are subject only to incident and annual reporting in part 191 (see section III.A below).

As described in the background section (II.A) above, modern gathering systems require larger, higher-pressure lines to meet the new supply and demand pressures than had been common when the existing requirements were put into place. This is not a theoretical problem: Failures on unregulated gas gathering lines have resulted in serious incidents, some with fatal consequences (see the discussion in section II.A above).

PHMSA appreciates the need to exercise caution in exercising its statutory authority to regulate gathering lines that have not been previously covered by parts 191 and 192 without clear, detailed safety data. This is why a new category of gathering lines is being created for reporting purposes only that are only subject to the incident and annual reporting requirements described in section III.A of this document. These are designated as ''Type R'' gathering lines in § 192.8. These lines are not regulated gathering lines under in part 192 but are subject to incident and annual reporting requirements in part 191.

However, there is ample basis upon which to add the targeted requirements in this final rule for Type C gathering lines that mirror the requirements already in place for existing, lower-stress Type B lines. These measures are an appropriate initial step to ensure basic safeguards to the public, property, and the environment while additional data is collected and analyzed. Additionally, withdrawing the proposed regulations in the NPRM for previously unregulated gas gathering lines in its entirety would be inconsistent with public safety and would not be responsive to GAO recommendation GAO–14–667 or the Congressional mandate in the 2020 PIPES Act. Therefore, PHMSA is adding the definition of Type C regulated gas gathering lines as proposed in the NPRM.

However, the new regulatory requirements are tailored to the potential hazards the newly regulated gathering lines may pose. This is described in more detail in section III.D below. PHMSA determined that certain programs, such as damage prevention, are foundational to pipeline safety and public trust and therefore should be required for all Type C gas gathering lines as originally proposed in the NPRM. However, other requirements apply only to Type C lines with an outside diameter greater than 16 inches, and Type C lines with an outside

[71] A composite pipe is made of a combination of either steel or plastic with a reinforcing material designed to maintain its circumferential and longitudinal strength. A common configuration consists of steel or fiber reinforcement layered between a polymer inside liner and outer shell. No composite materials are currently authorized for use in part 192 or part 195, but may be used through a special permit (*see* § 190.341).

diameter larger than 12.75 inches that are located near homes and other structures. The largest-diameter gas gathering lines and those that can directly impact local communities are required to comply with all of the requirements for newly regulated Type C (Type A, Area 2) gathering lines proposed in the NPRM. The proposed deadline to determine endpoints of newly regulated gathering lines remains unchanged in the final rule—6 months after the effective date. Operators must therefore identify the endpoints of newly regulated Type C lines on or before November 16, 2022. While the GPAC recommended a 2-year compliance deadline for identifying the endpoints of Type C gathering lines, such a delay is not necessary given that PHMSA understands that many Type C lines are of more recent vintage and therefore would generally have more robust records to facilitate determination of endpoints than older gathering lines. A prolonged identification period would also delay the important safety (section III.D. *infra*) and reporting (section III.A.4. *supra*) standards in the final rule. The Type C determination in § 192.8(c)(2) requires, at a minimum, knowledge only of the location, diameter, and pressure of the pipeline. Most Type C gathering lines are relatively modern shale gas systems and these basic records should be readily accessible.

PHMSA acknowledges that this deadline may be challenging for some operators of certain older, smaller-diameter, systems. The final rule therefore includes procedures for an operator to request an alternative compliance deadline with a notification in accordance with § 192.18. This is intended to mirror existing § 192.9(e)(2), which gives the PHMSA Administrator discretion to allow a later deadline if justified in a particular case. An operator must submit a written request to PHMSA in accordance with § 192.18 no later than 90 days prior to the standard compliance deadline. The request must include, at a minimum, a description of the facilities that require a delayed compliance date, the justification for an alternative compliance deadline, and the proposed alternative compliance deadline. An operator may proceed with their proposed compliance deadline if they receive a no-objection letter from PHMSA or if PHMSA does not reply within 90 days. If delayed identification impacts an operator's ability to comply with the requirements in § 192.9, they must submit a separate notification to request delayed compliance under that section.

The combination of changes discussed in this section and in section III.D below provides a reasonable and cost-effective initial approach to address the risks associated with previously unregulated gas gathering lines. PHMSA will monitor the safety performance of both newly regulated gas gathering and unregulated gas gathering lines and evaluate the need for further regulatory action in the future.

D. Safety Requirements for Newly Regulated Gas Gathering Lines—§§ 192.9, 192.13, 192.18, 192.452, and 192.619

1. Summary of PHMSA's Proposal

PHMSA proposed in the NPRM to apply part 192 safety requirements to the newly-established Type A, Area 2 lines (referred to as Type C lines in the final rule). These requirements, collectively referred to as Type C requirements in this final rule, are:

- § 192.9(d)(1)—Implement design, installation, construction, initial inspection, and initial testing requirements for new/replaced/relocated/changed lines in accordance with the requirements in part 192 for transmission lines.
- § 192.9(d)(2)—Adopt corrosion control measures for metallic pipe in accordance with part 192, subpart I, requirements for transmission lines.
- § 192.9(d)(3)—Adopt damage prevention measures in accordance with § 192.614.
- § 192.9(d)(4)—Develop public awareness programs in accordance with § 192.616.
- § 192.9(d)(5)—Establish MAOP in accordance with § 192.619.
- § 192.9(d)(6)—Install and maintain line markers in accordance with the requirements for transmission lines in § 192.707.
- § 192.9(d)(7)—Conduct leakage surveys in accordance with § 192.706, using leak- detection equipment and promptly repair hazardous leaks that are discovered, in accordance with § 192.703(c).
- § 192.9(d)(8)—Develop and implement procedures for emergency plans in accordance with § 192.615.

These requirements are the same as those that currently apply to Type B regulated gas gathering lines, except for the new emergency plans requirements. PHMSA also proposed conforming changes to §§ 192.13, 192.452, and 192.619.

2. Summary of Public Comment

Citizen and environmental groups expressed support for the proposed requirements for newly regulated gas gathering lines or suggested additional requirements. Several citizen groups suggested that gas gathering lines that function similarly to transmission lines should be regulated like transmission lines in part 192. Similarly, the Public Service Commission of West Virginia commented that the proposed requirements for Type A, Area 2 (now Type C) lines, which mirror the requirements for low-pressure, low-stress Type B gathering lines, are not adequate or sufficient to ensure the safety of large, high-pressure gas gathering lines and instead recommended that such pipelines follow existing Type A, Area 1 requirements (*i.e.* most gas transmission line requirements) that apply to other regulated gathering lines that operate with higher stress levels and pressures.

GPA Midstream and Kinder Morgan commented that Type A, Area 2 (now Type C) lines should not have to conduct leakage surveys with leak detection equipment, as currently required for Type B gathering lines in § 192.9(d)(7), since leaks and ruptures on higher-stress Type A lines are easier to detect without specialized equipment. API and TPA proposed that the emergency-planning requirements in § 192.9(d)(8) be revised to reference the existing requirements for other types of pipelines in § 192.615. They also recommended exempting operators of Type A, Area 2 (now Type C) regulated gathering lines from the requirement to have written procedures to respond to each of the emergency situations listed in § 192.615(a)(3), presumably for cost concerns. API, GPA Midstream, and Northeast Gas Association commented that the compliance cost estimates used in the RIA for Type A, Area 2 (now Type C) regulated gathering lines were underestimated and contained erroneous assumptions. For example, GPA Midstream raised concerns about the costs of program evaluation requirements under public awareness. Industry commenters were especially concerned about the applicability of the proposed gas transmission requirements in the NPRM such as the MAOP reconfirmation, including the cost to establish MAOP and confirm the material properties of gathering lines that were not previously required to have an MAOP or keep such records. PHMSA notes that these provisions were finalized by the Gas Transmission Final Rule and apply only to gas transmission lines.

A number of commenters articulated concerns about how the proposed regulations would affect the use of non-metallic materials in previously

unregulated gathering systems. Commenters representing gathering line operators and non-metallic pipe manufacturers urged PHMSA to consider the impact of the rule on gathering lines made of composite materials and polyethylene pipe manufactured to standards other than ASTM D2513. A composite pipe is made of a combination of either steel or plastic with a reinforcing material designed to maintain its circumferential and longitudinal strength. A common configuration consists of steel or fiber reinforcement layered between a polymer inside liner and outer shell. No composite materials are currently authorized for use in part 192 or part 195 but may be used through a special permit (see § 190.341).

Commenters were especially concerned with the possibility that existing, unregulated lines made of non-metallic materials would need to be replaced if they subsequently become regulated Type A, Area 2 (Type C) lines. API suggested that PHMSA incorporate by reference two standards, API Standard 15S, ''Spoolable Composite Pipe Systems,'' 1st edition and ASTM F2619/F2619M–13, ''Standard Specification for High-Density Polyethylene (PE) Line Pipe'' into § 192.9 to allow the use of composite materials and an alternative specification for polyethylene pipe that is commonly used in unregulated production and gathering operations. API and the Plastic Pipe Institute commented that the proposed repair criteria in the NPRM did not address non-metallic materials and could effectively eliminate the use of plastics and composites in Type A, Area 2 (now Type C) lines that previously had no such restrictions. GPA Midstream also commented that composite pipe can operate at pressures that would include them within the Type A, Area 2 (now Type C) criteria and should therefore be addressed in the rule.

3. GPAC Recommendations

GPAC voted 12–0 that the proposed minimum safety standards for Type A, Area 2 (Type C) regulated gathering lines were technically feasible, reasonable, cost-effective, and practicable, if the following changes were made:

- Extend the deadline for Type A, Area 2 (Type C) gathering lines that become regulated in the future due to new dwellings to comply with part 192 requirements from one year to two years after the effective date of the final rule;
- Add a notification process similar to the process endorsed by the committee for the gas transmission rule [72] to address the use of composite pipe materials in existing and new Type A, Area 2 (Type C) gathering lines;
- Extend the deadline in § 192.8(b) for determining if pipelines are classified as Type A, Area 2 (Type C) gathering lines from six months to two years after the effective date of the final rule;
- Extend the deadline for newly regulated gas gathering lines to comply with Type A, Area 2 (Type C) requirements to three years after the effective date of the rule, and make conforming changes (§§ 192.9(e)(3) and (4), 192.452, 192.13, and 192.619);
- Ensure that the language for designating newly regulated gas gathering lines is as clear as possible (*e.g.,* Type C vs. Type A, Area 2);
- Allow operators of Type A, Area 2 (Type C) gas gathering lines to establish MAOP based on a five-year high operating pressure; or via an alternative method with notification to PHMSA (§ 192.18 process); and
- Modify § 192.9 (d) to include Type A, Area 2 (Type C) gathering lines.

4. PHMSA Response

PHMSA understands the concerns expressed by the commenters regarding the application of existing pipeline safety requirements to newly regulated gas gathering lines. While the final rule does not significantly change the NPRM's proposed criteria for designating newly regulated Type C gas gathering lines (higher stress gathering lines with an outside diameter of 8.625 inches or greater, see section III.C), it does make changes to the NPRM's proposal regarding how each of the proposed Type C requirements are to be applied. These changes focus on applying more requirements to the highest-risk, largest-diameter gathering lines. The risk-based approach to Type C requirements in this final rule is based upon discussions at the June 25th GPAC meeting, consideration of the public comments received on the NPRM, and an analysis of the costs and benefits of various alternatives (see the RIA, available in the docket for this rule, for a detailed description of alternatives considered). As discussed during the GPAC meeting, PHMSA emphasizes that the Type C requirements are an initial step in addressing safety concerns with larger-diameter gas gathering lines. If PHMSA's analysis of the safety performance of regulated and unregulated gathering lines demonstrates a need to revise the requirements for regulated gathering lines, PHMSA can exercise its authority to do so in a future rulemaking.

The applicability of each of the requirements for Type C regulated gas gathering lines in the final rule is as follows:

Requirements for Type C gathering lines with outside diameters of 8.625 inches and greater:

- Design, installation, construction, and initial inspection and testing for lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 per transmission line requirements in part 192;
- Corrosion Control (part 192, subpart I);
- Damage Prevention Program (§ 192.614);
- Emergency Plans (§ 192.615);
- Public Awareness (§ 192.616);
- Line Markers (§ 192.707); and
- Leakage Surveys (§ 192.706).

Additional requirements for Type C gathering lines with outside diameters greater than 12.75 inches:

- Applicable requirements of part 192 for plastic pipe and components; and
- Establishment of MAOP (§ 192.619).

Exception: Gathering lines with an outer diameter 16 inches or less that are not located within a potential impact circle containing a building intended for human occupancy or other impacted sites must only comply with requirements governing damage prevention (§ 192.614); emergency plans (§ 192.615); and, for Type C lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 (*i.e.* 1 year after the effective date of the rule), certain design, installation, construction, initial inspection, and initial testing requirements applicable to transmission lines under part 192. These provisions are required for all Type C gathering lines regardless of size or location. The applicability of each of these requirements is summarized in the table below:

[72] This recommendation was subsequently codified as § 192.18 by the Gas Transmission Final Rule (84 FR 52180).

Outside diameter	*Not* located near a building intended for human occupancy or other impacted site (§ 192.9(f))	Located near a building intended for human occupancy or other impacted site (§ 192.9(f))
Greater than or equal to 8.625 inches up to and including 12.75 inches.	—Design, Construction, Initial Inspection and Testing (new/replaced/relocated/changed lines). —Damage Prevention ..... —Emergency plans	—Design, Construction, Initial Inspection and Testing (new/replaced/relocated/changed lines). —Corrosion Control. —Damage Prevention. —Emergency Plans. —Line Markers. —Public Awareness. —Leakage Surveys.
Greater than 12.75 inches up to and including 16 inches.	—Design, Construction, Initial Inspection and Testing (new/replaced/relocated/changed lines). —Damage Prevention. —Emergency Plans.	All Type C Requirements.
Greater than 16 inches	All Type C Requirements	All Type C Requirements.

The potential impact circle calculation criterion for certain Type C requirements is based on the method for identifying high-consequence areas in the gas transmission integrity management program regulations in subpart O of part 192. Specifically, the terms ''potential impact circle'' and ''potential impact radius (PIR),'' including the formula for calculating what the length of the potential impact radius,[73] are defined in § 192.903. The ''potential impact circle'' is the area around a pipeline where a pipeline rupture could cause severe consequences, such as casualties and destruction of property. PHMSA notes that the formula requires knowing the MAOP of the pipeline, rather than the actual operating pressure. Additionally, the final rule requires that operators of Type C gathering line use a factor of 0.73 for wet/rich natural gas in the PIR calculation rather than the 0.69 factor for dry natural gas used in the integrity management regulations. This results in a slightly larger potential impact circle reflecting the potentially more intense fire and explosion hazards due to the higher average energy content of unprocessed gas, which may contain higher concentrations of natural gas liquids and other hydrocarbons. A 2005 report prepared for PHMSA by Michael Baker Jr., Inc., titled, ''Potential Impact Radius Formulae for Flammable Gases other than Natural Gas Subject to 49 CFR 192'' [74] calculated that 0.73 was an appropriate PIR factor for pipelines transporting rich natural gas. The calculations are detailed in section 4.8.4 of the report using the same formula described in ASME B31.8S that is referenced in the gas transmission integrity management regulations. API RP 1182 uses the same factor for a similar PIR concept, however that document is not incorporated by reference in this rule. Similarly, § 192.9(f) in this final rule dictates that any Type C gathering line segment located within a potential impact circle containing a building intended for human occupancy or other impacted site must comply with all Type C requirements applicable for the diameter of that line, since a failure on that segment has the potential to cause catastrophic damage to local communities. This approach was discussed at the GPAC and in public comments and PHMSA agrees it is an effective way of prioritizing short-term regulatory action towards gas gathering lines with the highest potential consequences of a failure.

PHMSA recognizes that not all operators may be able to perform the potential impact radius calculation. If the gathering line segment does not have an established MAOP or other records necessary to perform the PIR calculation, the operator may perform the same determination on a class location unit (see § 192.5) basis rather than a potential impact circle basis. A class location unit is 1 mile in length and extends 220 yards on either side of the centerline of a pipeline. PHMSA notes that this uses the same ''sliding mile'' approach used for determining class locations rather than static mile-long increments stacked end-over-end. The class-location unit moves along the pipeline, and if the sliding mile contains a building intended for human occupancy or other impacted site at any point during the mile's movement, then the exception in paragraph (f) does not apply for the entire mile of pipeline contained within the sliding mile.

The class location unit method for applying these exceptions is used in API RP 1182 and provides a simpler, more conservative method for determining the applicability of the § 192.9(f) exception for operators that choose not to perform a PIR analysis or lack records of the parameters necessary to calculate the PIR. PHMSA expects that the class location unit method will result in fewer miles of gathering lines being covered by the § 192.9 exception in almost all circumstances because the additional requirements will apply for a mile on each side of a building intended for human occupancy or other impacted site. Theoretically, the PIR of a pipeline could exceed 220 yards; if this is the case it is possible that some structures could be captured by the PIR analysis but not the class location unit analysis. However, given that this exception is limited for Type C gathering lines 16 inches or less in outside diameter, it is unlikely that a gathering line 16 inches or less in diameter will operate at a pressure that would cause the calculated PIR to exceed the width of the class location unit. The MAOP of a pipeline with an outside diameter of 16 inches must exceed 3000 psig for the PIR of the pipeline to exceed 660 feet. A MAOP of 3000 psig is unusually high. Although PHMSA does not collect data on MAOP on annual reports, incident reports reveal that less than 1 percent of gas transmission incidents from 2010 through the end of 2021 involved a facility with an MAOP higher than 3000 psig; further, there were no incidents volving a pipeline larger than 10.75 inches in outside diameter, and no incidents on regulated onshore gas gathering lines.

In the final rule, operators must achieve compliance with applicable Type C requirements no later than 1

[73] *See* ASME B31.8S for additional information on calculating PIR.

[74] Michael Baker Jr., Inc. ''TTO Number 13: Potential Impact Radius Formulae for Flammable Gases Other than Natural Gas Subject to 49 CFR 192: Final Report'' (June 2005), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-transmission-integrity-management/65311/tto13potentialimpactradiusfinalreportjune2005.pdf.*

year after the effective date of the rule, unless PHMSA has approved an alternative compliance schedule after the operator has submitted a notification in accordance with § 192.18. This is a shorter compliance deadline than the 3-year phase in recommended by the GPAC (*i.e.,* 1-year after the endpoints of Type C have been identified). The safety standards in the final rule target known threats to public safety, and the most significant requirements are targeted at gathering lines with direct potential safety impacts (*i.e.,* has a potential impact circle containing a building intended for human occupancy). Due to these direct threats to the public, it is critical that operators implement minimum safety practices as soon as practicable. The final rule provides operators a total of 1½ years from the date of publication to implement these measures, which should be achievable for most operators.

However, PHMSA recognizes that some operators may encounter challenges in meeting the deadline for one or more of the Type C requirements. The final rule therefore includes procedures for an operator to request an alternative compliance deadline with a notification in accordance with § 192.18. This is intended to mirror existing § 192.9(e)(2), which allows the PHMSA Administrator flexibility to provide a later deadline if justified in a particular case. An operator must submit a written request to PHMSA in accordance with § 192.18 no later than 90 days prior to the standard compliance deadline. The request must include, at a minimum, a description of the facilities that require a delayed compliance date, the proposed alternative deadline, justification for the alternative compliance deadline, and actions the operator will take to ensure the safety of the affected facilities in the interim. The description of the pipeline facility and the operating environment should include relevant information about the integrity of the pipeline and the potential consequences in the case of the release. This includes: The diameter of the pipeline; the operating pressure; known design and construction specifications; results from surveys, patrols, or integrity assessments; and the presence of homes or other human uses near the pipeline. An operator may request an alternative compliance schedule for more than one requirement within § 192.9(e) in a single notice. However, the notice must include a proposed compliance schedule and justification for each requirement. An operator may proceed with their proposed compliance deadline if they receive a no-objection letter from PHMSA or if PHMSA does not reply within 90 days.

Consistent with the deadlines described above, design, construction, initial inspection, and initial testing requirements apply to all Type C lines that are new, replaced, relocated, or otherwise changed after the applicable compliance deadline in § 192.13 (*i.e.,* 1 year after the effective date of the rule). Additionally, in the final rule, operators of unregulated gas gathering lines that become Type C regulated gathering lines, or become subject to additional Type C requirements, due to a change in the pipeline's MAOP or the discovery of a building intended for human occupancy or other impacted site have 1 year from the time the change is discovered to comply with Type C requirements.

PHMSA determined that it was appropriate for all Type C gathering lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 (*i.e.,* 1 year after the effective date of the rule) to comply with the initial design, construction, inspection, and testing requirements applicable to transmission lines in part 192 to ensure that new, higher risk gathering lines are adequately designed and constructed. PHMSA also determined that it was appropriate for all Type C gathering lines to comply with damage prevention and emergency plan requirements in §§ 192.614 and 192.615, based on the incident history of transmission pipelines and fatal gas gathering incidents. For onshore gas transmission lines between 2010 and 2019, excavation damage was the third leading cause of incidents and the most common cause of incidents that resulted in fatal injuries.[75] As described in section II.A, many of the fatal incidents on unregulated gathering lines described in media reports have been caused by excavation damage. These incidents commonly cause serious and fatal injuries regardless of the diameter or location of the pipeline since equipment operators and other workers may be in close proximity to the point of failure. However, effective damage prevention programs and participation in One-Call programs can reduce this risk. Based on gas transmission line incident report data, both the number of excavation damage incidents and the share of incidents caused by excavation damage has trended downwards between 2000 and 2018. While gathering lines are covered under damage prevention and One-Call laws in most States, PHMSA expects that requiring operators to implement a damage prevention program under part 192 may improve enforcement of these requirements and cover lines in States where gathering lines are excepted. Maintaining a written damage prevention procedure and communicating damage prevention information to the public may also result in safety benefits beyond compliance with State One-Call laws from operators and excavators becoming more cognizant of the risks of third-party damage to gathering lines.

The requirements for emergency plans in § 192.615 directly address concerns with operator and community emergency response and planning capability. Emergency response plans and procedures for rural gathering lines were areas of emphasis in GAO's August 2014 report on safety requirements for transporting energy products.[76] In that report, the NTSB, a representative of the National Association of State Fire Marshals and emergency response officials agreed that ''emergency response plans are critical for pipeline safety;'' however, those emergency officials were concerned that responders in rural areas lacked the information about unregulated gathering lines in their communities to prepare for and respond to pipeline emergencies. Requiring all Type C gathering lines to comply with § 192.615 addresses these concerns by bringing emergency planning requirements for such pipelines in line with existing requirements for gas transmission lines.

PHMSA disagrees with the comment that Type C gas gathering lines should be excepted from the requirement to develop and follow procedures for responding to common types of pipeline emergencies listed in § 192.615(a)(3), such as gas leaks in structures, fires, explosions, and natural disasters. This requirement is necessary to help ensure effective emergency preparedness. As described in the background section II of this document and the GAO–14–667 report, emergency response capabilities are especially important for gas gathering systems operating in communities that do not have experience with intensive oil and gas development.

Design, installation, construction, initial inspection, and initial testing

[75] Out of 1,057 incidents reported to PHMSA that occurred during this period, 150 were due to excavation damage. Of the 13 incidents that resulted in fatal injuries, 6 were caused by excavation damage.

[76] GAO, GAO–14–667, ''Oil and Gas Transportation: Department of Transportation is Taking Actions to Address Rail Safety, but Additional Actions are Needed to Improve Pipeline Safety'' (Aug. 2012).

requirements, and corrosion control measures in part 192 are intended to reduce the likelihood of a release caused by material and equipment failure, corrosion, and excavation damage. Design, installation, construction, initial inspection, and initial testing requirements are prospective only. Operators are not expected to replace facilities existing on or prior to the compliance deadline in § 192.13 (*i.e.,* 1 year after the effective date of the rule) in order to comply with these requirements. PHMSA expects there will be safety benefits from applying part 192 design, construction, initial inspection, and initial testing requirements should those existing lines require replacement, relocation or otherwise be changed.

In the NPRM, PHMSA did not intend to prohibit the use of composite pipe materials on previously unregulated Type C gathering lines or require the removal of such materials. However, the existing part 192 requirements were written for steel or conventional plastic pipe. Additionally, the NPRM did not propose to incorporate by reference API RP 15S or F2619/F2619M–13 and PHMSA has not yet conducted the technical review of those documents needed to support their incorporation by reference in this final rule.

To address composite pipe, PHMSA has added a provision in the final rule to allow operators to install or replace composite pipe that is not otherwise authorized by part 192 for use in regulated Type C gas gathering lines upon notification to PHMSA pursuant to §§ 192.9(h) and 192.18. Operators may use composite pipe or materials as proposed in their notification if, after 91 days, they have not received a letter from PHMSA with either an objection to the proposed use of composite pipe, or that states that PHMSA requires additional time to conduct its review. PHMSA may also proactively issue a no-objection letter. Additionally, operators may continue to use composite pipe installed on or before the effective date of the rule; no notification under §§ 192.9(h) and 192.18 would be required in those circumstances. This change affects Type C gathering lines only and does not authorize the use of composite pipe for any other type of pipeline covered under part 192. Under the § 192.18 notification process, PHMSA will evaluate the operator's proposed operation and maintenance procedures, which includes the operator's proposed remediation methods and procedures for identifying defects and determining the safe operating pressures of composite pipe when defects are found. PHMSA will not approve notifications that it determines are inconsistent with pipeline safety. An objection letter issued under § 192.18 will not foreclose an operator's ability to seek a special permit in accordance with § 190.341. Additional information on this process is provided in the section-by-section analysis of this document. PHMSA may use data obtained from observing the design, construction, and operation of composite materials in Type C gathering lines to inform its future decisions on whether and how to accept composite materials for pipelines in other jurisdictional applications.

Public awareness requirements in § 192.616 and line marker requirements in § 192.707 apply to Type C lines that are located near buildings intended for human occupancy, and further address residual risks despite part 192 damage prevention and emergency planning requirements. Public awareness requirements in § 192.616 require additional communication with excavators, first responders, local governments, and the public. Notably, this provision at § 192.616(d) obliges operators to describe the potential hazards of a pipeline release, the physical markers of a release, and how to respond to customers and other members of the community. This requirement is especially important for members of the public to identify dangerous releases on gas pipelines that are not odorized. These communications improve safety by encouraging individuals to take safe actions such as contacting One-Call before performing excavations and recognizing, avoiding, and reporting gas leaks. Section 192.707 requires the placement of line markers at road and railroad crossings, and wherever else the operator deems is necessary. These markers provide a visual reminder of the presence of otherwise invisible pipelines and serve to reduce third-party damage risks. Additionally, during emergencies, line markers communicate hazards and operator contact information to first responders.

After consideration of public comments, the recommendations of the GPAC, and the final RIA that accompanies this final rule, PHMSA has retained the requirement for leakage surveys in § 192.706 for both (1) all Type C gathering lines with an outside diameter greater than 16 inches, as well as (2) Type C gathering lines with an outer diameter greater than 8.625 inches but not exceeding 16 inches in outside diameter that are located in a potential impact circle containing a building intended for human occupancy or other impacted site. In other words, this requirement applies to larger-diameter gas gathering lines and those that could directly impact nearby structures and people during a rupture. Since Class 1 gas gathering lines are not typically odorized and the leakage survey requirement applies to larger diameter Type C gathering lines or those located near people, PHMSA has retained the requirement that operators use leak detection equipment when conducting leakage surveys. Leak detection equipment is already required for leakage surveys on gas transmission lines that are not odorized.

Part 192 does not currently establish technology or performance standards for leak detection equipment, and the NPRM did not propose to establish standards for leak detection equipment. The final rule therefore does not specify what constitutes ''leak detection equipment.'' Any equipment capable of detecting all leaks on the pipeline system would be acceptable.[77] Traditionally, operator personnel perform an instrumented leakage survey by walking along the pipeline right-of-of way with handheld leak detection equipment, such as a flame ionization detection device, laser-based methane detector, or other equipment. Similar equipment can be installed on vehicles or at fixed locations along the right of way. Some technology providers claim to detect smaller leaks from greater distances using a combination of vehicular or aerial sensor platforms, sensitive gas detectors, other sensors, and analytics. There are also various methods for continuous leak monitoring, including pressure and pressure wave monitoring, fixed gas detectors, and fiber optic-based distributed sensing. Performing leakage surveys increases the likelihood that small defects are discovered and remediated before they evolve into more significant failures with potentially severe impacts to people, nearby structures, and the environment. Leakage surveys are also necessary to mitigate the climate change impacts of methane leaks.

Lastly, consistent with the GPAC recommendations, PHMSA adopts the remaining requirements proposed in the NPRM for application to all Type C lines with an outside diameter of greater than 16 inches, and Type C lines with an outside diameter greater than 12.75 inches but not exceeding 16 inches in outer diameter, that are located near buildings intended for human

[77] *See, e.g.,* PHMSA, Interpretation Letter No PI–01–0104, Letter to Richard Motsinger (Apr. 3, 2001), *https://www.phmsa.dot.gov/regulations/title49/interp/PI-01-0104.*

occupancy or other impacted sites. For example, MAOP determinations will also be required for Type C gathering lines with an outside diameter greater than 16 inches, and Type C lines larger than 12.75 inches in outside diameter up to and including 16 inches in outside diameter that are located in a potential impact circle containing a building intended for human occupancy or other impacted sites. The amendments proposed in the NPRM to the tables in § 192.619(a)(3) that would give existing Type C gathering lines the option of establishing an MAOP based on historical operating pressure have been incorporated into the final rule. Therefore, newly regulated Type C lines now will have the option of establishing MAOP using the highest actual operating pressure to which the segment was subjected during the five years (60 months) preceding the effective date of the rule, or five years (60 months) before first becoming subject to the rule, whichever is later.

However, PHMSA supports the GPAC recommendation to allow operators of Type C gas gathering lines to establish MAOP using alternative methods pursuant to the notification process set forth in § 192.18 and the requirements of § 192.619(c)(2). PHMSA is persuaded that allowing alternative methods with PHMSA approval under § 192.18 for establishing the MAOP of a previously unregulated Type C gas gathering line existing on or before the effective date of the rule is appropriate. Such operators were not previously required to make and maintain records of MAOP, pressure tests, or operating pressure and may not have traceable, verifiable, and complete records necessary to calculate an MAOP using the lowest of each of the methods listed in § 192.619. This final rule includes a new § 192.619(c)(2) and conforming changes to § 192.18 to allow an operator of an existing Type C regulated gathering lines based on available records. Under this process, the operator would propose an MAOP based on the information available about the pipeline, such as actual highest operating pressure, operational and maintenance history, pressure test records, and information about the design and material properties of the pipeline. The new paragraph specifies the minimum information required to be submitted to PHMSA in the notification. The ''no objection'' process in § 192.18 requires PHMSA to respond within 90 days. If, after 90 days, PHMSA has not responded to the notification, the operator would be allowed to use the ''other technology'' method to establish MAOP. This approach is not permitted for natural gas pipeline facilities other than Type C regulated gathering lines.

The risk-based application of each of these Type C requirements is based on the operational and functional characteristics of those lines and strikes an appropriate balance between the need to protect people and the environment from the risks associated with large-diameter, high-pressure gathering lines and the need to exercise caution imposing regulatory burdens before more detailed information can be collected. The most substantive requirements apply to all Type C gathering lines with outer diameter of more than 16 inches and Type C gathering lines larger than 12.75 inches up through and including 16 inches that could directly affect homes, businesses, and other building intended for human occupancy. This approach focuses more stringent compliance measures on gas gathering lines that pose the most significant potential hazard to people and the environment. The requirements that remain for Type C gathering lines with an outside diameter of 12.75 inches or less include initial design, construction and testing requirements, leakage surveys emergency planning, damage prevention, and corrosion control. While the GPAC recommended PHMSA consider applying leakage survey requirements to all Type C gathering lines, PHMSA has concluded that more detailed information on the extent and safety performance of such pipelines is needed to justify applying those requirements for Type C lines 16 inches in outside diameter and smaller that do not have a building intended for human occupancy within the PIR. However, as discussed at the GPAC meeting and in this final rule, PHMSA will use the data collected from the new reporting requirements to evaluate continuously PHMSA's oversight of gas gathering lines and determine if additional requirements are appropriate in the future.

There is no potential impact circle or class-location unit-based exception for Type C gathering lines larger than 16 inches in outside diameter. PHMSA considered alternatives raised in the GPAC discussions and public comments, such as having no limit to the potential impact circle exception or limiting it to an outside diameter of 24 inches. After considering these factors and the revised RIA, PHMSA ultimately determined that the 16-inch limit for the PIR exception initially presented to the committee was appropriate. PHMSA notes that API and other industry commenters on the NPRM suggested 16 inches or greater, without a PIR exception, as an alternative definition for Type C. Many of the Type C requirements applicable to larger pipelines relate to initial design, construction, and corrosion control issues, and it is important for such pipelines to be properly constructed, tested, coated, and have cathodic protection applied before new homes and other buildings intended for human occupancy are built nearby in the future—because such measures reduce associated safety risks. Additionally, the volume of a pipeline and the energy released during a rupture increase exponentially as pipe diameter increases. A rupture on a larger-diameter pipeline, all else being equal, is therefore more likely to have consequences other than direct damage to structures. These include externalized economic disruptions to downstream users and environmental consequences such as methane emissions and ecological damage. These external consequences can be significant even if the potential impact radius of a pipeline segment is smaller than the width of a gas transmission class location unit (660 ft.).

The NPRM's other proposed changes, including revisions to § 192.619(a)(4) and 192.619(e), only apply to gas transmission lines. In the Gas Transmission Final Rule, PHMSA clarified which new regulatory requirements from the NPRM apply only to gas transmission lines by including exceptions to those requirements for Type A and Type B gathering lines § 192.9(c). In this final rule, Type C lines are also exempt from these requirements. Several other regulatory changes proposed in the NPRM, specifically the proposed repair criteria, were intended to apply solely to gas transmission lines. PHMSA expects to clarify the applicability of those requirements when the final rule addressing the repair criteria for gas transmission lines is published under RIN 2137–AF39.

In response to comments and additional analysis, PHMSA has also updated the RIA. The revisions and clarifications described above reduce the cost of the requirements in § 192.9. Specifically, the most significant of the proposed requirements will now apply only to large-diameter pipelines and certain smaller-diameter pipelines that are located within a potential impact circle containing a building intended for human occupancy or other impacted sites. Additionally, clarifying that the recordkeeping, material verification, and MAOP reconfirmation requirements proposed in the NPRM were not intended to apply to gathering or distribution lines addresses a large share

of the cost concerns raised in the comments.

IV. Section-by-Section Analysis

§ 191.1 Scope

Part 191 prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipelines. Section 191.1 identifies the scope of applicability of the reporting requirements. PHMSA is revising § 191.1(a) to more clearly state that part 191 applies to offshore and onshore gas gathering not excepted by § 191.1(b). This change is intended to define the existing scope of part 191 to offshore gas gathering lines and the revised applicability to onshore gas gathering lines in plain language. PHMSA is revising § 191.1(b) to remove the exception to part 191 in § 191.1(b)(4) for unregulated, onshore gas gathering lines, including gathering lines that operate at less than 0 psig or are located within the inlets of the Gulf of Mexico. Incident Reports and Annual Reports will now be required for all onshore gas gathering lines, including Type R gathering lines. The expanded reporting requirements for previously unregulated gas gathering lines will provide data for monitoring the safety performance of these pipelines and a sound basis for evaluating if future regulatory changes are needed. However, this final rule excepts Type R gas gathering lines from requirements for OPID validation in § 191.22(b), notifications in § 191.22(c), and safety-related condition reports in § 191.23. Operators must still update their OPID information (*e.g.,* change in primary entity, change in name) before submitting an incident or annual report if a change has occurred.

§ 191.3 Definitions

PHMSA is adding definitions for ''regulated onshore gathering'' and ''reporting-regulated gathering.'' The term ''regulated onshore gathering'' is defined as a Type A, Type B, or Type C gas gathering line as determined in accordance with § 192.8. The term ''reporting-regulated gathering'' is defined as an onshore gathering pipeline other than a regulated onshore gathering pipeline. These pipelines have been designated as ''Type R'' gathering lines in § 192.8 but are not regulated under that part.

§ 191.15 Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities: Incident Report

This revision requires operators of Type R gathering pipelines to submit incident reports using DOT Form PHMSA F 7100.2–2. Regulated gathering lines, including Type C gathering lines, must continue to submit reports using DOT Form PHMSA F 7100.2.

For Type R gathering lines, an incident report is required for any event meeting the definition of an incident that occurs after the effective date of the rule. Operators are not required to categorize and report retroactively events which occurred before the effective date of the rule. The form excludes information related to part 192 requirements that do not apply.

§ 191.17 Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities: Annual Report

This section prescribes requirements for submitting annual reports. This final rule adds a paragraph (a)(2) that specifies the annual reporting requirements for operators of Type R gathering lines. Such operators must complete and submit DOT Form PHMSA F 7100.2–3. The first report is due no later than March 15, 2023 for the 2022 reporting year. The form instructions address how to report data attributes that are unknown.

§ 191.23 Reporting Safety-Related Conditions

This section specifies requirements for submitting safety-related conditions. In this final rule, paragraph (b)(1) is revised to except Type R gathering lines from safety-related condition reporting requirements in §§ 191.23 and 191.25.

§ 191.29 National Pipeline Mapping System

Section 191.29 specifies requirements for participation in the National Pipeline Mapping System (NPMS). Section 60132 of the Federal Pipeline Safety Law requires operators of a pipeline facilities excluding distribution and gathering lines to provide information to be included in the NPMS. In response to comments, the final rule clarifies that the requirements in § 191.29 do not apply to gas gathering lines. Although § 191.29(a) states the requirement applies only to operators of gas transmission lines and liquefied natural gas (LNG) facilities, the final rule makes the exclusion of gas gathering lines, including regulated onshore gas gathering lines, more explicit.

§ 192.3 Definitions

Section 192.3 defines certain terms used in part 192. The final rule adds a definition for ''composite materials.'' The term ''composite materials'' means the materials used to make pipes or components manufactured with a combination of either steel and/or plastic and a reinforcing material to maintain their circumferential or longitudinal strength. This definition is added to describe the process for notifying PHMSA prior to the use of composite materials on new, replaced, relocated, or otherwise changed Type C gathering lines in § 192.9. This definition alone does not authorize the use of composite pipe or materials under this part.

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

Section 192.8 describes how onshore pipelines and segments are determined to be onshore gathering lines and regulated onshore gathering lines. The definition of regulated onshore gathering line has been redesignated as paragraph (c). The final rule adds a new paragraph (b) to specify that gas gathering line must maintain records documenting the methodology used to determine the beginning and endpoints of segments determined to be gas gathering lines as determined in accordance with part 192. This final rule specifies that these records must be established within 1 year of the effective date of the rule, or within 1 year of pipeline installation, whichever is later. These records include the API RP 80 definitions and methods used to define the beginning and endpoints and where those points are located (*e.g.,* mile markers, address, or coordinates). Operators must maintain these records for the life of the pipeline, meaning until the pipeline is removed from the ground or permanently abandoned in place in accordance with § 192.727. An operator may request an alternative compliance deadline with a notification to PHMSA submitted in accordance with § 192.18 if the standard compliance deadline is impracticable. This notification must include a description of the affected facilities and operating environment, the justification for an alternative compliance deadline, and the operator's proposed alternative deadline. This notification must be submitted to PHMSA no later than 90 days prior to the standard compliance deadline in § 192.8(b)(1). The operator

may proceed with their proposed alternative deadline if they receive a no objection letter from PHMSA or if PHMSA has not replied within 90 days of submitting the notification.

The final rule also revises § 192.8(a)(5) to address the use of the incidental gathering concept described in API RP 80. For new, replaced, relocated, or otherwise changed gas gathering lines installed after the effective date of this final rule, the ''incidental gathering'' concept, as described in section 2.2.1.2.6 of API RP 80, may not be used if the ''incidental'' endpoint in paragraph 2.2(a)(1)(E) of API RP 80 is 10 miles or more from the furthermost downstream point where a gathering line end as determined in accordance with paragraphs 2.2 (a)(1)(A) through (a)(1)(D) of API RP 80 and § 192.8 (*e.g.* processing facilities, compressor stations, points of comingling). A new, replaced, relocated, or otherwise changed pipeline that is designated as an ''incidental gathering'' pipeline in API RP 80 but is 10 miles or more in length will be considered a transmission pipeline subject to all applicable portions of parts 191 and 192. Incidental gathering lines existing on or before the effective date of the rule may continue to operate as a gathering line, regardless of length.

One major aspect of this final rule is to identify a new category of regulated onshore gas gathering lines, designated as Type C lines in § 192.8. As discussed previously, a Type C regulated onshore gathering line is defined as any onshore gathering line that is 8.625 inches or larger in outside diameter, is located in a Class 1 location, and meets one of the following criteria, as applicable.

- Metallic pipe and the MAOP produces a hoop stress of 20 percent or more of SMYS;
- Metallic pipe and, if the stress level is unknown, the MAOP is more than 125 psig (862 kPa); or
- Non-metallic and the MAOP is more than 125 psig (862 kPa).

The minimum safety standards applicable to Type C gathering lines are specified in the revisions to § 192.9. The final rule adds the new Type C category to the table in § 192.8(b)(2). The purpose of adding this new category of regulated gas gathering lines is to ensure that operators of larger-diameter, higher-pressure gas gathering lines in Class 1 locations follow a basic set of requirements targeting known threats to public safety and pipeline integrity such as excavation damage, corrosion, and construction defects.

§ 192.9 What requirements apply to gathering lines?

This final rule codifies the minimum safety standards for Type C regulated gas gathering lines. The requirements for Type C gathering lines in this final rule are broken down as follows:

Type C requirements for pipelines with outside diameter of 8.625 inches and greater:

- Design, installation, construction, and initial inspection and testing per transmission line requirements in part 192 for lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13;
- Corrosion control (part 192, subpart I);
- Damage prevention program (§ 192.614);
- Emergency plans (§ 192.615);
- Public awareness (§ 192.616);
- Line markers (§ 192.707); and
- Leakage surveys (§ 192.706).

Additional Type C requirements for pipelines with an outside diameter of 12.75 inches and greater:

- Applicable requirements of part 192 for plastic pipe and components; and
- Establish MAOP (§ 192.619).

The final rule adds § 192.9(f), which creates an exception from certain part 192 requirements if a Type C gathering line has a diameter of 16 inches or less and is not located near local communities as determined by one of the following methods:

Method 1. Potential Impact Circle. The segment is not located within a potential impact circle as defined in § 192.903 containing a building intended for human occupancy or other impacted site. This is the same method used to determine HCAs in the gas transmission integrity management regulations. Note that similar to the method for identifying HCAs, any point on a pipeline located *within* any potential impact circle containing a building intended for human occupancy or other impacted site may not apply the exception even if a potential impact circle drawn from that point does not contain such a location itself (Refer to Figure E.I.A. in appendix E to part 192).

The formula for calculating a potential impact radius is defined in § 192.903. PHMSA notes that this formula requires knowledge of the MAOP and nominal diameter of the pipeline. If the segment does not have an MAOP established in accordance with § 192.619, or if the diameter is unknown, the operator must use method 2 or not apply the exception and comply with the Type C requirements that are applicable based on the diameter of the pipeline. Additionally, operators must use a factor of 0.73 rather than the dry gas factor of 0.69 used in the integrity management regulations. The increased factor accounts for the potentially higher combustion energy of unprocessed natural gas, which may contain varying amounts of other combustible hydrocarbons.

Method 2: Class Location Unit. This analysis is similar to Method 1. However instead of calculating a potential impact circle, the class location unit as defined in § 192.5(a)(1) is used. This is the ''sliding mile'' or ''continuous-mile'' analysis used for class location determination. A class location unit is 1 mile in length and extends 220 yards on either side of the centerline of a pipeline. PHMSA notes that this uses the same ''sliding mile'' approach used for determining class location rather than static mile-long increments stacked end-over-end. The class-location unit moves along the pipeline, and if the sliding mile contains a building intended for human occupancy or other impacted site at any point during the mile's movement, then the exception in paragraph (f) does not apply for the entire mile of pipeline contained within the sliding mile. This method does not require knowledge of the pipeline's MAOP.

For the purposes of applying this exception, ''building intended for human occupancy'' or ''other impacted site'' is defined in § 192.9(f)(4) to mean any of the following:

- One or more buildings that may be occupied by humans, including homes, office buildings factories, outside recreation areas, and plant facilities.
- A small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive). This has the same meaning and interpretation as the Class 3 criterion in § 192.5(b)(3)(ii); or
- Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes. This has the same meaning and interpretation of section (1)(ii) of the ''moderate consequence area'' definition in § 192.3.

The table below summarizes the applicability of the Type C requirements based on the size and location of a given segment.

Outside diameter	*Not* located near a building intended for human occupancy or other impacted site (§ 192.9(f))	Located near a building intended for human occupancy or other impacted site (§ 192.9(f))
Greater than or equal to 8.625 inches up to and including 12.75 inches.	—Design, Construction, Initial Testing (new/replaced/relocated/changed lines). —Damage Prevention. —Emergency plans.	—Design, Construction, Initial Testing (new/replaced/relocated/changed lines). —Corrosion Control. —Damage Prevention. —Emergency Plans. —Line Markers. —Public Awareness. —Leakage Surveys.
Greater than 12.75 inches up to and including 16 inches.	—Design, Construction, Initial Testing (new/replaced/relocated/changed lines). —Damage Prevention. —Emergency Plans.	All Type C Requirements.
Greater than 16 inches	All Type C Requirements	All Type C Requirements.

Section 60104(b) of the Pipeline Safety Acts exempts new design, installation, construction, initial inspection, and initial testing standards from applying to gathering lines that existed before the effective date of this final rule. In other words, if a previously unregulated gas gathering line becomes regulated by operation of this final rule (and is not itself replaced, relocated, or otherwise changed after the compliance date in § 192.13), the operator is not required to bring retroactively that pipeline facility into compliance with the new design, installation, construction, initial inspection, and initial testing requirements.

The rule also adds an exception in § 192.9(f)(3) to these requirements for segments shorter than 40 feet [78] that are installed, relocated, or changed on Type C gathering lines that were installed before the effective date of the rule. Regulations in part 192 that do not pertain to design, installation, construction, initial installation, or initial testing may apply to the segment regardless of the date of installation.

In § 192.9(g)(4), existing gathering lines that become classified as Type C regulated gathering lines due to the publication of this final rule have a 1-year compliance deadline to meet the applicable requirements in this section. An operator may request an alternative compliance deadline with a notification to PHMSA submitted in accordance with § 192.18 if the standard compliance deadline is impracticable. This notification must include a description of the affected facilities and operating environment and, for each requirement that requires an alternative compliance deadline: The justification for an alternative compliance deadline, and the operator's proposed alternative deadline. The notification must also include a description of actions the operator will take to ensure the safety of the affected facilities in the interim. This notification must be submitted no later than 90 days prior to the standard compliance deadline. The operator may proceed with their proposed alternative deadline if they receive a no objection letter from PHMSA or if PHMSA has not replied within 90 days of submitting the notification.

In § 192.9(g)(5), operators of gathering lines that become classified as Type C regulated gathering lines in the future due to an increase in MAOP, a change in dwelling density, or a change in class location have a 1-year compliance deadline to meet the requirements of this section. Similarly, an operator of a Type C gathering line that becomes subject to additional Type C requirements in the future, for example when a change in dwelling density or increased MAOP causes the exceptions in paragraph (f) to no longer apply, has a 1-year compliance deadline to meet those additional requirements. Conforming changes were made to paragraphs (g)(2) and (3) to clarify that the existing implementation deadlines now apply only to Type A and Type B regulated gathering lines.

The final rule also adds a new paragraph (h) to clarify that operators may install or replace pipe or components made of composite materials that are not otherwise authorized in part 192 on Type C gathering lines upon submittal of a notification to PHMSA pursuant to § 192.18, unless PHMSA issues an objection letter to the operator's notification. Under the § 192.18 notification process, PHMSA will evaluate the operator's proposed operation and maintenance procedures, which includes the operator's proposed remediation methods and procedures for identifying defects and determining the safe operating pressures of composite pipe when defects are found. PHMSA will not approve notifications that are not consistent with pipeline safety. A rejection under § 192.18 will not foreclose an operator's ability to seek a special permit in accordance with § 190.341.

Operators may continue to operate gathering lines containing composite pipe or materials existing on or before the effective date of the rule without notification to PHMSA. However, operators of Type C pipelines must comply with all other applicable Type C requirements once the final rule becomes effective. Additionally, per new § 192.9(e)(1)(i), notification is not required for replacements, relocations, or changes of composite pipe segments 40 feet or less in length on pipelines that were installed before the effective date of the rule. Replacements using composite materials on Type C gathering lines, including composite materials installed per a notification, require notification to PHMSA regardless of length. Replacing a segment of composite pipe with steel or plastic pipe and components authorized under part 192 does not require notification. The notification requirement does apply to repairs involving replacements, relocations, or significant changes to the pipe. If an operator discovers a condition that requires immediate replacement, operators should describe all urgent conditions in their notification to PHMSA, request an emergency special permit under § 190.341, or conduct the repair using materials authorized under part 192, such as steel.

§ 192.13 What general requirements apply to pipelines regulated under this part?

This is a conforming change that repeats the compliance deadlines for Type C lines in § 192.8 and clarifies that the previously existing compliance deadlines for regulated gas gathering lines in that section continue to apply

[78] A single length of pipe is typically 40 feet in length.

to Type A and Type B regulated gathering lines.

§ 192.18 How To Notify PHMSA

This is a conforming change in the final rule to allow the use of the notification procedures in this section to comply with §§ 192.8(b) and (g)(4), 192.9(h), and 192.619(c)(2).

§ 192.150 Passage of Internal Inspection Devices

Currently, this section provides that Type A regulated gathering lines are exempt from the requirement that new gas transmission lines be able to accommodate the passage of instrumented internal inspection devices. This amendment clarifies that lower-risk Type B and Type C lines are also exempt.

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

This section of the final rule documents conforming changes to address the applicability of part 192, subpart I, to unregulated gathering lines that become Type C onshore regulated gathering lines. Specifically, it covers previously unregulated gathering lines that become regulated by operation of this final rule. Additionally, it covers previously unregulated gathering lines that become subject to Type C corrosion control requirements in the future due to a change in MAOP or the presence of a building intended for human occupancy or other impacted site. Such pipelines are treated as if they were installed before August 1, 1971, for the purposes of subpart I. The final rule also clarifies in paragraph (d) that gathering lines that are subject to subpart I at the time of construction must meet the corrosion control requirements applicable to pipelines installed after July 31, 1971.

§ 192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

This section of the final rule includes conforming changes on the applicability of § 192.619 for determining the MAOP for newly regulated gathering lines, *i.e.,* Type C lines. Additionally, a new paragraph (c)(2) has been added to allow operators of newly regulated Type C gas gathering lines to establish an MAOP using ''other technology'', upon notification to PHMSA in accordance with § 192.18. This process would only be available to segments where the MAOP was established under § 192.619(c) and the operator does not have the requisite operational pressure records because the pipeline was previously unregulated and not required to retain such records. The justification of the proposed MAOP must be reviewed and accepted by a qualified technical subject matter expert. PHMSA expects a qualified subject matter expert to be an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. The operator must be able to document that the individual is appropriately knowledgeable and experienced in the subject being assessed.

V. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 80 standards and specifications developed and published by standard development organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices. Sometimes multiple editions are published in a given year.

The National Technology Transfer and Advancement Act of 1995 (NTTAA, Pub. L. 104–113) directs Federal agencies to use standards developed by voluntary consensus standards bodies in lieu of government-written standards whenever possible. Voluntary consensus standards bodies develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, OMB issued Circular A–119 to implement section 12(d) of the NTTAA relative to the utilization of consensus technical standards by Federal agencies.[79] This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in the NTTAA.

Accordingly, PHMSA has the responsibility for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to the Federal Pipeline Safety Regulations. Revisions to materials incorporated by reference in the Federal Pipeline Safety Regulations are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

Pursuant to 49 U.S.C. 60102(p), PHMSA may not issue amendments to the Federal Pipeline Safety Regulations that incorporate by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge. Further, the Office of the Federal Register issued a rulemaking on November 7, 2014, revising 1 CFR 51.5(b) to require that agencies detail in the preamble of a final rule how the materials being incorporated by reference are reasonably available to interested parties, and how interested parties can obtain those materials.[80]

The only standard incorporated by reference in the final rule is API RP 80. Free, online, read-only access to API RP 80 is available on the API website (*http://publications.api.org/AccessToDocuments.aspx;* navigate to the ''Exploration and Production'' category). Members of the public interested in obtaining API RP 80 can contact API using the contact information in this final rule's revisions to the regulatory text at § 192.7. In addition, PHMSA will provide individual members of the public temporary access to this or any other standard that is incorporated by reference in the Federal Pipeline Safety Regulations. Requests for access can be sent to the following email address: *phmsaphpstandards@dot.gov.*

VI. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of Federal Pipeline Safety Law. Section 60101(b) authorizes the Secretary of Transportation to prescribe standards defining the term ''gathering line'' that account for the functional and operational characteristics of a pipeline. That section also authorizes the Secretary to prescribe standards defining the term ''regulated gathering line,'' which must consider factors such as location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas. In addition, 49 U.S.C. 60102 authorizes the Secretary to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. Further, 49 U.S.C. 60117(b)(2) authorizes the Secretary to require owners and operators of gathering lines to submit information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines. The

[79] 81 FR 4673 (Jan. 27, 2016).

[80] Incorporation by Reference, 79 FR 66278.

Secretary delegated his authority to the PHMSA Administrator under 49 CFR 1.97.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866 (''Regulatory Planning and Review'') [81] requires that agencies ''should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.'' Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, Executive Order 12866 requires that ''agencies should select those [regulatory] approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.'' Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts.

Executive Order 12866 and DOT Order 2100.6A require that PHMSA submit ''significant regulatory actions'' to the Office of Management and Budget (OMB) for review. This final rule has been determined to be significant under section 3(f) of Executive Order 12866 and was reviewed by OMB. It is also considered significant under DOT Order 2100.6. The Office of Information and Regulatory Affairs (OIRA) has not designated this rule as a ''major rule'' as defined by the Congressional Review Act (5 U.S.C. 801 *et seq.*).

Executive Order 12866 and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which reinforces requirements for notice and comment in the Administrative Procedure Act (APA, 5 U.S.C. 551 *et seq.*). In accord with the requirement, PHMSA sought public comment on the proposals in the NPRM (including preliminary cost and cost savings analyses pertaining to those proposals), as well as any information that could assist in evaluating the benefits and costs of this rulemaking. Those comments are addressed, and additional discussion about the economic impacts of the final rule are provided, within the final regulatory impact analysis (RIA) posted in the docket.

PHMSA expects benefits of the final rule to consist of improved safety and avoided environmental harms (including greenhouse gas emissions) from reduction of risk of failures of onshore natural gas gathering lines due to improved leak detections and subsequent repairs. The expected benefits will depend on the degree to which compliance actions result in additional safety measures, relative to the baseline, and the effectiveness of these measures in preventing or mitigating future pipeline failures. PHMSA estimates annualized costs of $13.7 million per year using a 7 percent discount rate. The costs for compliance with annual reporting and, for Type C gathering lines, compliance with part 192 are expected to be higher in the initial compliance period, as operators will incur one-time costs to achieve compliance in the years leading up to the compliance deadline. Thereafter recurring costs are expected to be lower. For more information, please see the RIA posted in the rulemaking docket.

C. Environmental Justice

DOT Order 5610.2C and Executive Orders 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[82] 13985 (''Advancing Racial Equity and Support for Underserved Communities Through the Federal Government''),[83] 13990 (''Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis''),[84] and 14008 (''Tackling the Climate Crisis at Home and Abroad'') [85] require DOT agencies to achieve environmental justice as part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects, including interrelated social and economic effects, of their programs, policies, and activities on minority populations, low-income populations, and other disadvantaged communities.

PHMSA has evaluated this final rule under DOT Order 5610.2C and the Executive orders listed above and has determined it would not cause disproportionately high and adverse human health and environmental effects on minority populations, low-income populations, or other underserved and disadvantaged communities. The rulemaking is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to adversely impact any particular population, region, or community. And insofar as PHMSA expects the rulemaking would reduce the safety and environmental risks associated with onshore natural gas gathering lines, many of which are located in the vicinity of environmental justice communities,[86] PHMSA does not expect the regulatory amendments introduced by this final rule would entail disproportionately high adverse risks for minority populations, low-income populations, or other underserved and other disadvantaged communities in the vicinity of those pipelines. Lastly, as explained in final environmental assessment (EA), PHMSA expects that the regulatory amendments in this final rule will yield greenhouse gas emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority, low-income, underserved, and other disadvantaged populations and communities.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA, 5 U.S.C. 601 *et seq.*) requires Federal regulatory agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the APA unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. This final rule was developed in accordance with Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'') [87] to promote compliance with the RFA and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA does not have access to firm-level data on gathering line operators that are not currently regulated under part 191 or 192. However, based on data on regulated gathering line operators produced by Dun and Bradstreet, approximately 40 percent of currently regulated gathering line operators are identified as small entities, and those entities operate approximately 24 percent of onshore regulated gas gathering line mileage. Therefore, a

[81] 58 FR 51375 (Oct. 4, 1993).

[82] 59 FR 7629 (Feb. 16, 1994).

[83] 86 FR 7009 (Jan. 20, 2021).

[84] 86 FR 7037 (Jan. 20, 2021).

[85] 86 FR 7619 (Feb. 1, 2021).

[86] *See* Ryan Emmanuel, et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5:6 GeoHealth (June 2021), *https://agupubs.onlinelibrary.wiley.com/toc/24711403/2021/5/6* (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

[87] 67 FR 53461 (Aug. 16, 2002).

significant share of affected entities can be classified as small entities. However, PHMSA expects the magnitude of the economic impact on those entities to be limited, as the annualized costs of the final rule represent only approximately 0.1 percent of annual industry revenues for the entire crude oil transportation industry (NAICS code 486110), illustrating the minor financial impact on firms operating within this space. PHMSA has prepared a FRFA, available in the docket for the rulemaking, in which PHMSA certifies that the rule will not have a significant impact on a substantial number of small entities.

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

PHMSA analyzed this final rule in accordance with the principles and criteria in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'') [88] and DOT Order 5301.1 (''Department of Transportation Programs, Polices, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Executive Order 13175 requires agencies to assure meaningful and timely input from Tribal government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities or the relationship and distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the rulemaking and determined that it would not significantly or uniquely affect Tribal communities or Indian Tribal governments. The rulemaking's regulatory amendments are facially neutral and would have broad, national scope; PHMSA, therefore, does not expect this rulemaking to significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or mandate Tribal action. And insofar as PHMSA expects the rulemaking will improve natural gas gathering line safety and reduce environmental risks, PHMSA does not expect it would entail disproportionately high adverse risks for Tribal communities. PHMSA also received no comments alleging ''substantial direct compliance costs'' or ''substantial direct effects'' on Tribal communities and Governments. For these reasons, PHMSA has determined the funding and consultation requirements of Executive Order 13175 and DOT Order 5301.1 do not apply.

F. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. PHMSA expects this final rule to impact the information collections described below.

PHMSA will submit an information collection revision request to OMB for approval based on the requirements in this final rule. The information collections are contained in the pipeline safety regulations, 49 CFR parts 190 through 199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burdens for the following information collections are estimated to be revised as follows:

1. *Title:* Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 01/31/2023.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. This mandatory information collection request would require owners and/or operators of gas pipeline systems to make and maintain records in accordance with the requirements prescribed in 49 CFR part 192 and to provide information to the Secretary of Transportation at the Secretary's request. Certain records are maintained for a specific length of time while others are required to be maintained for the life of the pipeline. PHMSA uses these records to verify compliance with regulated safety standards and to inform the agency on possible safety risks.

Based on the provisions in the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, PHMSA estimates that 370 new Type C gas gathering pipeline operators ~ (91,000 Type C miles w/o prior regulation) will be subject to these requirements. PHMSA estimates that it will take these 370 operators 6 hours to create and maintain records associated with 49 CFR 192.9 requirements. Therefore, PHMSA expects to add 370 responses and 2,220 hours to this information collection as a result of the provisions in this final rule.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,861,842.

Total Annual Burden Hours: 1,677,030.

Frequency of Collection: On occasion.

2. *Title:* Annual and Incident Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 10/31/2024.

Abstract: This mandatory information collection covers the collection of annual and immediate notice of incident report data from Gas pipeline operators. As a result of the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, all gas gathering operators will become subject to incident and annual reporting requirements. PHMSA is revising this information collection to account for the new addition to the reporting community. PHMSA will require 500 currently unregulated gas gathering line operators (370 Type C operators and 130 Type R operators) to complete and submit annual reports each year. Type C operators will submit annual report data on DOT Form PHMS F7 100.2–1. The estimated burden for submitting this form is 47 hours per report. Type R operators will submit annual report data on the new DOT Form PHMSA F7 100.2–3. The estimated burden for submitting this form is 21 hours per report. These changes will result in an overall annual burden increase of 20,120 hours (17,390 hours annually for Type C operators and 2,730 hours annually for Type R operators) for this information collection.

Gas Gathering operators will also be required to make immediate telephonic notification of incidents, should they occur. PHMSA expects that these previously unregulated operators will make approximately 85 telephonic notifications of incidents per year. PHMSA estimates that it takes 30 minutes to complete a telephonic notification. As such, the estimated burden for gas gathering operators to make immediate notification of incidents is approximately 43 hours.

As a result of the provisions mentioned above, the burden for this information collection will increase by 585 new responses and 10,543 burden hours.

Affected Public: Natural Gas Pipeline Operators.

[88] 65 FR 67249 (Nov. 6, 2000).

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 2,832.

Total Annual Burden Hours: 91,964.

Frequency of Collection: Annually and on occasion.

3. *Title:* Incident Reports for Natural Gas Pipeline Operators.

OMB Control Number: 2137–0635.

Current Expiration Date: 10/31/2024.

Abstract: Operators of natural gas pipelines and LNG facilities are required to report incidents, on occasion, to PHMSA per the requirements in 49 CFR part 191. This mandatory information collection covers the collection of incident report data from natural gas pipeline operators. The reports contained within this information collection support the Department of Transportation's strategic goal of safety. This information is an essential part of PHMSA's overall effort to minimize natural gas transmission, gathering, and distribution pipeline failures. Due to the provisions contained within the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, operators will be required to submit reports of incidents that occur on previously unregulated gas gathering systems.

Based on PHMSA's estimate of the mileage of Type C and Type R gas gathering pipelines and the incident rate on Type A and Type B gas gathering pipelines, PHMSA expects to receive approximately 85 incident reports (18 Type C incident reports and 67 Type R incident reports) each year from gas gathering operators. As a result, the burden for this information collection will increase by 85 responses. The burden per incident report is estimated at 12 hours per report. This results in an estimated burden increase of 1,020 hours (216 hours for Type C and 804 hours for Type R) per year.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 344.

Total Annual Burden Hours: 4,128.

Frequency of Collection: On occasion.

4. *Title:* National Registry of Pipeline and LNG Operators.

OMB Control Number: 2137–0627.

Current Expiration Date: 01/31/2023.

Abstract: The National Registry of Pipeline and LNG Operators serves as the storehouse for the reporting requirements for an operator regulated or subject to reporting requirements under 49 CFR part 192, 193, or 195. This mandatory information collection would require jurisdictional pipeline operators to submit the required data to register with the National Registry of Pipeline and LNG Operators and notify PHMSA when they experience significant asset changes, including new construction, that affect PHMSA's ability to accurately monitor and assess pipeline safety performance. Certain types of changes to, or within, an operator's facilities or pipeline network represent potential safety-altering activities for which PHMSA may need to inspect, investigate, or otherwise oversee to ensure that any public safety concerns are adequately and proactively addressed. The forms for assigning and maintaining Operator Identification (OPID) information are the Operator Assignment Request Form (PHMSA F 1000.1) and Operator Registry Notification Form (PHMSA F 1000.2). The purpose of this information collection is to maintain an accurate assessment of the Nation's pipeline infrastructure and to be kept abreast of conditions that could potentially compromise the safety and economic viability of the U.S. pipeline system.

Due to the provisions contained within the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, gas gathering pipeline operators must now request OPIDs due to the repeal of the reporting exception for gathering pipelines other than regulated gathering lines as determined in § 192.8. PHMSA plans to revise the OPID Registry form and instructions to account for this addition to the reporting community. PHMSA believes that many operators of previously unregulated gathering lines are already submitting annual report data for regulated gas gathering lines and may already have an OPID. As such, PHMSA expects to receive approximately 13 new OPID requests. PHMSA also requires these newly regulated operators to submit notifications to PHMSA in certain instances. PHMSA similarly expects to receive approximately 13 new notifications from gas gathering pipeline operators. These additions will result in an increase to the burden of this information collection by 26 responses and 26 burden hours.

Affected Public: Operators of Natural Gas, Hazardous Liquid, and Liquefied Natural Gas pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 744.

Total Annual Burden Hours: 744.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, Telephone (202) 366–1246.

G. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (UMRA, 2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate of $100 million or more (in 1996 dollars) in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate. PHMSA prepared a final RIA and determined that this final rule does not impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more (in 1996 dollars) in any one year. A copy of the RIA is available for review in the docket of this rulemaking.

H. National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA, 42 U.S.C. 4321 *et seq.*) requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA has completed its NEPA analysis. Based on the environmental assessment, PHMSA determined that an environmental impact statement is not required for this rulemaking because it will not have a significant impact on the human environment. The final EA and Finding of No Significant Impact have been placed into the docket addressing the comments received.

I. Executive Order 13132: Federalism

PHMSA analyzed this final rule in accordance with Executive Order 13132 (''Federalism'').[89] Executive Order 13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have a substantial direct effect on State and local governments, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. The final rule exercises PHMSA's existing authority to require operators of gas gathering line to submit safety data (49 U.S.C. 60117(b)(2)) and to define and establish safety standards for regulated gas gathering lines (49 U.S.C. 60101(b)). PHMSA determined the final rule's changes to the requirements for onshore gas gathering lines were necessary based on the results of PHMSA's review of existing gas gathering requirements performed pursuant to section 21 of the 2011 Pipeline Safety Act.

Section 60104(c) of Federal Pipeline Safety Law prohibits certain State safety regulation of interstate pipelines. Under the pipeline safety laws, States that have submitted a current certification under section 60105(a) can augment Federal pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate.

In this instance, the preemptive effect of the final rule is limited to the minimum level necessary to achieve the objectives of the Federal Pipeline Safety Law under which the final rule is promulgated. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

J. Executive Order 13211: Significant Energy Actions

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'')[90] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Executive Order 13211 defines a ''significant energy action'' as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation that (1)(i) is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy (including a shortfall in supply, price increases, and increased use of foreign supplies); or (2) is designated by the Administrator of the OIRA as a significant energy action.

This final rule is a significant action under Executive Order 12866; however, it is expected to have an annual effect on the economy of less than $100 million. Further, this final rule is not likely to have a significant adverse effect on supply, distribution, or energy use, as further discussed in the RIA. Further, OIRA has not designated this final rule as a significant energy action.

K. Privacy Act Statement

In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its rulemaking process. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *www.dot.gov/privacy.*

L. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN number contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

M. Executive Order 13609 and International Trade Analysis

Executive Order 13609 (''Promoting International Regulatory Cooperation'')[91] requires agencies to consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA participates in the establishment of international standards to protect the safety of the American public. PHMSA has assessed the effects of the rulemaking and determined that it will not cause unnecessary obstacles to foreign trade.

List of Subjects

49 CFR Part 191

MAOP exceedance, Pipeline reporting requirements.

49 CFR Part 192

Incorporation by reference, Integrity assessments, MAOP reconfirmation, Material verification, Pipeline safety, Predicted failure pressure, Reporting and recordkeeping requirements, Risk assessment, Safety devices.

In consideration of the foregoing, PHMSA amends 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. The heading for part 191 is revised to read as set forth above.

■ 3. In § 191.1, paragraphs (a) and (b)(2) and (3) are revised, paragraph (b)(4) is removed, and paragraph (c) is added to read as follows:

[89] 64 FR 43255 (Aug. 10, 1999).

[90] 66 FR 28355 (May 22, 2001).

[91] 77 FR 26413 (May 4, 2012).

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in the United States or Puerto Rico, including underground natural gas storage facilities and pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). This part applies to offshore gathering lines (except as provided in paragraph (b) of this section) and to onshore gathering lines, including Type R gathering lines as determined in § 192.8 of this chapter.

(b) * * *

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9; or

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

(c) Sections 191.22(b) and (c) and 191.23 do not apply to the onshore gathering of gas—

(1) Through a pipeline that operates at less than 0 psig (0 kPa);

(2) Through a pipeline that is not a regulated onshore gathering pipeline; or

(3) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612 of this chapter.

■ 4. In § 191.3, add definitions for ''Regulated onshore gathering'' and ''Reporting-regulated gathering'' in alphabetical order to read as follows:

§ 191.3 Definitions.

* * * * *

Regulated onshore gathering means a Type A, Type B, or Type C gas gathering pipeline system as determined in § 192.8 of this chapter.

Reporting-regulated gathering means a Type R gathering line as determined in § 192.8 of this chapter. A Type R gathering line is subject only to this part.

* * * * *

■ 5. In § 191.15, paragraph (a) is revised to read as follows:

§ 191.15 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

(a) *Pipeline systems*—(1) *Transmission or regulated onshore gathering.* Each operator of a transmission pipeline system or a regulated onshore gathering pipeline system must submit Department of Transportation (DOT) Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5.

(2) *Reporting-regulated gathering.* Each operator of a reporting-regulated gathering pipeline system must submit DOT Form PHMSA F 7100.2–2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 that occurs after May 16, 2022.

* * * * *

■ 6. In § 191.17, paragraph (a) is revised to read as follows:

§ 191.17 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.

(a) *Pipeline systems*—(1) *Transmission or regulated onshore gathering.* Each operator of a transmission or a regulated onshore gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(2) *Type R gathering.* Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2–3. This report must be submitted each year, not later than March 15, for the preceding calendar year.

* * * * *

■ 7. In § 191.23, revise paragraph (b)(1) to read as follows:

§ 191.23 Reporting safety-related conditions.

* * * * *

(b) * * *

(1) Exists on a master meter system, a reporting-regulated gathering pipeline, or a customer-owned service line;

* * * * *

■ 8. In § 191.29, paragraph (c) is added to read as follows:

§ 191.29 National Pipeline Mapping System.

* * * * *

(c) This section does not apply to gathering pipelines.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 9. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

■ 10. In § 192.3, add a definition for ''Composite materials'' in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Composite materials means materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

* * * * *

■ 11. Amend § 192.8 as follows:
■ a. Revise the section heading;
■ b. Add paragraph (a)(5);
■ c. Redesignate paragraph (b) as a paragraph (c);
■ d. Add new paragraph (b); and
■ e. Revise newly redesignated paragraph (c).

The revisions and addition read as follows:

§ 192.8 How are onshore gathering pipelines and regulated onshore gathering pipelines determined?

(a) * * *

(5) For new, replaced, relocated, or otherwise changed gas gathering pipelines installed after May 16, 2022, the endpoint of gathering under sections 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 (incorporated by reference, *see* § 192.7)—also known as ''incidental gathering''—may not be used if the pipeline terminates 10 or more miles downstream from the furthermost downstream endpoint as defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 (incorporated by reference, *see* § 192.7) and this section. If an ''incidental gathering'' pipeline is 10 miles or more in length, the entire portion of the pipeline that is designated as an incidental gathering line under 2.2(a)(1)(E) and 2.2.1.2.6 of

API RP 80 shall be classified as a transmission pipeline subject to all applicable regulations in this chapter for transmission pipelines.

(b) Each operator must determine and maintain for the life of the pipeline records documenting the methodology by which it calculated the beginning and end points of each onshore gathering pipeline it operates, as described in the second column of table 1 to paragraph (c)(2) of this section, by:

(1) November 16, 2022, or before the pipeline is placed into operation, whichever is later; or

(2) An alternative deadline approved by the Pipeline and Hazardous Materials Safety Administration (PHMSA). The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include the following information:

(i) Description of the affected facilities and operating environment;

(ii) Justification for an alternative compliance deadline; and

(iii) Proposed alternative deadline.

(c) For purposes of part 191 of this chapter and § 192.9, the term ''regulated onshore gathering pipeline'' means:

(1) Each Type A, Type B, or Type C onshore gathering pipeline (or segment of onshore gathering pipeline) with a feature described in the second column of table 1 to paragraph (c)(2) of this section that lies in an area described in the third column; and

(2) As applicable, additional lengths of pipeline described in the fourth column to provide a safety buffer:

TABLE 1 TO PARAGRAPH (c)(2)

Type	Feature	Area	Additional safety buffer
A	—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. —If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is more than 125 psig (862 kPa).	Class 2, 3, or 4 location (*see* § 192.5)	None.
B	—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is 125 psig (862 kPa) or less.	*Area 1.* Class 3, or 4 location *Area 2.* An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location; (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	If the gathering pipeline is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2(b) or 2(c) qualifies a pipeline as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.
C	Outside diameter greater than or equal to 8.625 inches and any of the following: —Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS; —If the stress level is unknown, segment is metallic and the MAOP is more than 125 psig (862 kPa); or —Non-metallic and the MAOP is more than 125 psig (862 kPa).	Class 1 location	None.
R	—All other onshore gathering lines	Class 1 and Class 2 locations	None.

(3) A Type R gathering line is subject to reporting requirements under part 191 of this chapter but is not a regulated onshore gathering line under this part.

■ 12. Amend § 192.9 as follows:

■ a. Revise the section heading;

■ b. Redesignate paragraph (e) as paragraph (g);

■ c. Add a new paragraph (e) and paragraph (f);

■ d. Revise newly redesignated paragraphs (g)(2) and (3);

■ e. Add paragraphs (g)(4) and (5); and

■ f. Add paragraph (h).

The revisions and additions read as follows:

§ 192.9 What requirements apply to gathering pipelines?

* * * * *

(e) *Type C lines.* The requirements for Type C gathering lines are as follows.

(1) An operator of a Type C onshore gathering line with an outside diameter greater than or equal to 8.625 inches must comply with the following requirements:

(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B though G and J of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.205, 192.227(c), 192.285(e), and 192.506 is not required;

(ii) If the pipeline is metallic, control corrosion according to requirements of

subpart I of this part applicable to transmission lines except for § 192.493;

(iii) Carry out a damage prevention program under § 192.614;

(iv) Develop and implement procedures for emergency plans in accordance with § 192.615;

(v) Develop and implement a written public awareness program in accordance with § 192.616;

(vi) Install and maintain line markers according to the requirements for transmission lines in § 192.707; and

(vii) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706 using leak-detection equipment, and promptly repair hazardous leaks in accordance with § 192.703(c).

(2) An operator of a Type C onshore gathering line with an outside diameter greater than 12.75 inches must comply with the requirements in paragraph (e)(1) of this section and the following:

(i) If the pipeline contains plastic pipe, the operator must comply with all applicable requirements of this part for plastic pipe or components. This does not include pipe and components made of composite materials that incorporate plastic in the design; and

(ii) Establish the MAOP of the pipeline under § 192.619(a) or (c) and maintain records used to establish the MAOP for the life of the pipeline.

(f) *Exceptions.* (1) Compliance with paragraphs (e)(1)(ii), (v), (vi), and (vii) and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met:

(i) *Method 1.* The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in § 192.903, except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with paragraph (e)(2)(ii) of this section.

(ii) *Method 2.* The segment is not located within a class location unit (*see* § 192.5) containing a building intended for human occupancy or other impacted site.

(2) Paragraph (e)(1)(i) of this section is not applicable to pipeline segments 40 feet or shorter in length that are replaced, relocated, or changed on a pipeline existing on or before May 16, 2022.

(3) For purposes of this section, the term ''building intended for human occupancy or other impacted site'' means any of the following:

(i) Any building that may be occupied by humans, including homes, office buildings factories, outside recreation areas, plant facilities, etc.;

(ii) A small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive); or

(iii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

(g) * * *

(2) If a Type A or Type B regulated onshore gathering pipeline existing on April 14, 2006, was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the pipeline listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
(i) Control corrosion according to requirements for transmission lines in subpart I of this part	April 15, 2009.
(ii) Carry out a damage prevention program under § 192.614	October 15, 2007.
(iii) Establish MAOP under § 192.619	October 15, 2007.
(iv) Install and maintain line markers under § 192.707	April 15, 2008.
(v) Establish a public education program under § 192.616	April 15, 2008.
(vi) Other provisions of this part as required by paragraph (c) of this section for Type A lines	April 15, 2009.

(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering pipeline to become a Type A or Type B regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the pipeline becomes a regulated onshore gathering pipeline to comply with this section.

(4) If a Type C gathering pipeline existing on or before May 16, 2022, was not previously subject to this part, an operator must comply with the applicable requirements of this section, except for paragraph (h) of this section, on or before:

(i) May 16, 2023; or

(ii) An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include a description of the affected facilities and operating environment, the proposed alternative deadline for each affected requirement, the justification for each alternative compliance deadline, and actions the operator will take to ensure the safety of affected facilities.

(5) If, after May 16, 2022, a change in class location, an increase in dwelling density, or an increase in MAOP causes a pipeline to become a Type C gathering pipeline, or causes a Type C gathering pipeline to become subject to additional Type C requirements (*see* paragraph (f) of this section), the operator has 1 year after the pipeline becomes subject to the additional requirements to comply with this section.

(h) *Composite materials.* Pipe and components made with composite materials not otherwise authorized for use under this part may be used on Type C gathering pipelines if the following requirements are met:

(1) Steel and plastic pipe and components must meet the installation, construction, initial inspection, and initial testing requirements in subparts B though G and J of this part applicable to transmission lines.

(2) Operators must notify PHMSA in accordance with § 192.18 at least 90 days prior to installing new or replacement pipe or components made of composite materials otherwise not authorized for use under this part in a Type C gathering pipeline. The notifications required by this section must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including:

(i) The beginning and end points (stationing by footage and mileage with latitude and longitude coordinates) of the pipeline segment containing composite pipeline material and the counties and States in which it is located;

(ii) A general description of the right-of-way including high consequence areas, as defined in § 192.905;

(iii) Relevant pipeline design and construction information including the year of installation, the specific composite material, diameter, wall thickness, and any manufacturing and construction specifications for the pipeline;

(iv) Relevant operating information, including MAOP, leak and failure history, and the most recent pressure test (identification of the actual pipe tested, minimum and maximum test pressure, duration of test, any leaks and any test logs and charts) or assessment results;

(v) An explanation of the circumstances that the operator believes make the use of composite pipeline material appropriate and how the design, construction, operations, and maintenance will mitigate safety and environmental risks;

(vi) An explanation of procedures and tests that will be conducted periodically over the life of the composite pipeline material to document that its strength is being maintained;

(vii) Operations and maintenance procedures that will be applied to the alternative materials. These include procedures that will be used to evaluate and remediate anomalies and how the operator will determine safe operating pressures for composite pipe when defects are found;

(viii) An explanation of how the use of composite pipeline material would be in the public interest; and

(ix) A certification signed by a vice president (or equivalent or higher officer) of the operator's company that operation of the applicant's pipeline using composite pipeline material would be consistent with pipeline safety.

(3) Repairs or replacements using materials authorized under this part do not require notification under this section.

■ 13. In § 192.13, paragraphs (a) and (b) are revised to read as follows:

§ 192.13 What general requirements apply to pipelines regulated under this part?

(a) No person may operate a segment of pipeline listed in the first column of paragraph (a)(3) of this section that is readied for service after the date in the second column, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part according to the requirements in § 192.14.

(3) The compliance deadlines are as follows:

Pipeline	Date
(i) Offshore gathering pipeline.	July 31, 1977.
(ii) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006.	March 15, 2007.
(iii) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022.	May 16, 2023.
(iv) All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column of this paragraph (b) that is replaced, relocated, or otherwise changed after the date in the second column of this paragraph (b), unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
(1) Offshore gathering pipeline.	July 31, 1977.
(2) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006.	March 15, 2007.
(3) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022.	May 16, 2023.
(4) All other pipelines	November 12, 1970.

* * * * *

■ 14. In § 192.18, paragraph (c) is revised to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if the notification is made pursuant to § 192.8(b)(2), § 192.9(g)(4)(ii) and (h), § 192.461(g), § 192.506(b), § 192.607(e)(4) and (5), § 192.619(c)(2), § 192.624(c)(2)(iii) and (c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv) and (e)(2)(i)(E), § 192.921(a)(7), § 192.927(b), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*i.e.,* ''other technology'') that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

■ 15. Amend § 192.150 as follows:

■ a. In paragraph (b)(7)(ii), remove the word ''and'';

■ b. Redesignate paragraph (b)(8) as paragraph (b)(9); and

■ c. Add a new paragraph (b)(8).

The addition reads as follows:

§ 192.150 Passage of internal inspection devices.

* * * * *

(b) * * *

(8) Gathering lines; and

* * * * *

■ 16. In § 192.452, revise the section heading and paragraph (b) introductory text and add paragraphs (c) and (d) to read as follows:

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering pipelines?

* * * * *

(b) *Type A and B onshore gathering lines.* For any Type A or Type B regulated onshore gathering line under § 192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under § 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

* * * * *

(c) *Type C onshore regulated gathering lines.* For any Type C onshore regulated gathering pipeline under § 192.9 existing on May 16, 2022, that was not previously subject to this part, and for any Type C onshore gas gathering pipeline that becomes subject to this subpart after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

(d) *Regulated onshore gathering lines generally.* Any gathering line that is subject to this subpart per § 192.9 at the time of construction must meet the requirements of this subpart applicable to pipelines installed after July 31, 1971.

■ 17. In § 192.619, revise paragraph (a)(3) and paragraph (c) to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) * * *

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
(i) Onshore regulated gathering pipeline (Type A or Type B under § 192.9(d)) that first became subject to this part (other than § 192.612) after April 13, 2006.	March 15, 2006, or date pipeline becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
(ii) Onshore regulated gathering pipeline (Type C under § 192.9(d)) that first became subject to this part (other than § 192.612) on or after May 16, 2022.	May 16, 2023, *or date pipeline becomes subject to this part, whichever is later.*	5 years preceding applicable date in second column.
(iii) Onshore transmission pipeline that was a gathering pipeline not subject to this part before March 15, 2006.	March 15, 2006, or date pipeline becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
(iv) Offshore gathering pipelines	July 1, 1976	July 1, 1971.
(v) All other pipelines	July 1, 1970	July 1, 1965.

* * * * *

(c) The requirements on pressure restrictions in this section do not apply in the following instances:

(1) An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611.

(2) For any Type C gas gathering pipeline under § 192.9 existing on or before May 16, 2022, that was not previously subject to this part and the operator cannot determine the actual operating pressure of the pipeline for the 5 years preceding May 16, 2023, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA. The operator must notify PHMSA in accordance with § 192.18. The notification must include the following information:

(i) The proposed MAOP of the pipeline;

(ii) Description of pipeline segment for which alternate methods are used to establish MAOP, including diameter, wall thickness, pipe grade, seam type, location, endpoints, other pertinent material properties, and age;

(iii) Pipeline operating data, including operating history and maintenance history;

(iv) Description of methods being used to establish MAOP;

(v) Technical justification for use of the methods chosen to establish MAOP; and

(vi) Evidence of review and acceptance of the justification by a qualified technical subject matter expert.

* * * * *

Issued in Washington, DC on November 2, 2021, under authority delegated in 49 CFR 1.97.

Tristan H. Brown,

Acting Administrator.

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FEDERAL REGISTER

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Part IV

The President

Proclamation 10305—Veterans Day, 2021

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Presidential Documents

Title 3—

The President

Proclamation 10305 of November 9, 2021

Veterans Day, 2021

By the President of the United States of America

A Proclamation

For generations, millions of Americans have answered the call to serve—taking the sacred oath to defend and preserve our Nation's ideals of liberty and democracy. These patriots represent the best of us. On Veterans Day, we honor their service, dedication, and valor and are forever grateful for their sacrifice.

Our Nation has only one truly sacred obligation: to properly prepare and equip our service members when we send them into harm's way and to care for them and their families when they return home. For our 19 million veterans, that means ensuring that they have access to the support and resources for a future of security, opportunity, and dignity. This is even more important as we continue to recover from the global COVID–19 pandemic.

Our obligation to support our Nation's veterans and their families is personal for me and the entire Biden family, and I remain committed to ensuring that every veteran receives the care and support they have earned. The recently passed bipartisan Infrastructure Investment and Jobs Act will create millions of good jobs for veterans and grow opportunities for veteran-owned businesses. My Build Back Better framework also prioritizes improvements to VA health care, ensuring that every veteran—including our often-underserved female and LGBTQ+ veterans—receives competent, world-class health care through the Department of Veterans Affairs. Last month, the White House Gender Policy Council released the first-ever United States Strategy for Gender Equity and Equality, which included the unique needs and contributions of women service members and veterans. And the Department of Veterans Affairs is also working to get every eligible veteran the information and opportunity they need to register and vote, protecting their voice in the democracy they fought to preserve.

Ensuring veterans have timely access to services and benefits is at the center of my Administration's commitment to fulfilling our sacred obligation. This includes addressing the adverse health effects of service-related exposures. In August, the Department of Veterans Affairs announced it will begin processing disability claims for respiratory conditions connected to exposure during military service in Southwest Asia and other areas. My Administration also added three conditions to the list of those presumptively associated with exposure to Agent Orange, ending the long wait for disability benefits for many Vietnam era veterans. In the coming months, we are committed to taking additional action to address potential adverse health effects associated with military environmental exposures.

So many of our veterans carry the scars from their service—both visible and invisible—and it is our Nation's responsibility to help them heal. Too many veterans and service members have considered suicide or taken their own lives, and addressing this tragedy is a national responsibility. That is why I have made military and veteran suicide prevention a top priority, and earlier this month, I released a new comprehensive, cross-sector public health strategy to reduce military and veteran suicide. Implementing this approach will unite us around a common mission and accelerate meaningful

improvements in suicide prevention programs, helping us live up to our sacred obligation to those who have served in our Nation's Armed Forces.

Fulfilling our Nation's promise to our veterans and military families, caregivers, and survivors is not only a moral imperative—it is crucial to our national security and to maintaining the finest military the world has ever known. We are a Nation that keeps our promises. That is why my Administration is dedicated to a whole-of-government approach in responding to the needs of our veterans and their families, caregivers, and survivors.

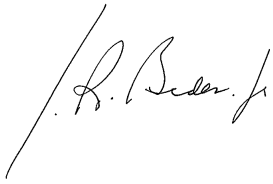
Through the First Lady's work with Joining Forces—the White House initiative to support veteran and military families, caregivers, and survivors—my Administration is addressing employment and entrepreneurship, military and veteran child education, and health and well-being for veteran families. Earlier this year, the First Lady met with military and veteran families to learn how we can better support and prioritize their needs, and in September, Joining Forces and the National Security Council released a report outlining the first round of Administration-wide commitments and proposals that support veteran and military families, caregivers, and survivors. These efforts will honor our sacred obligation to support our veteran families and ensure they receive the resources they need to thrive.

On Veterans Day, we honor our Nation's veterans, who have given so much to protect our freedoms and the freedom of others around the globe. They represent the highest ideals of our country. While we can never fully repay the debt we owe these heroes, we will honor their service and provide them the care and support they deserve. We also salute and show gratitude for all who ensure our Armed Forces remain strong, united, and unmatched.

In respect and recognition of the contributions our veterans and their families, caregivers, and survivors have made to the cause of peace and freedom around the world, the Congress has provided (5 U.S.C. 6103(a)) that November 11 of each year shall be set aside as a legal public holiday to honor our Nation's veterans.

NOW, THEREFORE, I, JOSEPH R. BIDEN JR., President of the United States of America, do hereby proclaim November 11, 2021, as Veterans Day. I encourage all Americans to recognize the valor, courage, and sacrifice of our veterans through appropriate ceremonies and private prayers. I call upon Federal, State, and local officials to display the flag of the United States of America and to participate in patriotic activities in their communities. And I call on all Americans, including civic and fraternal organizations, places of worship, schools, and communities, to support this day with commemorative expressions and programs.

IN WITNESS WHEREOF, I have hereunto set my hand this ninth day of November, in the year of our Lord two thousand twenty-one, and of the Independence of the United States of America the two hundred and forty-sixth.



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H.R. 4172/P.L. 117–57
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